Fort Frances Power Corporation



2014 Cost of Service Application

EB-2013-0130

Submitted December 20, 2013

Licence Number: ED-2003-0028

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15, as amended;

AND IN THE MATTER OF an Application by Fort Frances Power Corporation to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2014.

TITLE OF PROCEEDING:	An Application by Fort Frances Power Corporation for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2014.
APPLICANTS NAME:	Fort Frances Power Corporation
APPLICANTS ADDRESS:	320 Portage Avenue, Fort Frances, Ontario P9A 3P9 Attention: Joerg Ruppenstein, President and CEO Phone: 807-274-9291 Fax: 807-274-9375 Email: ffpc@fort-frances.com Doug McCaig, Chairman Fort Frances Power Corporation Lori Cain, Finance & Regulatory Officer Phone: 807-274-9291

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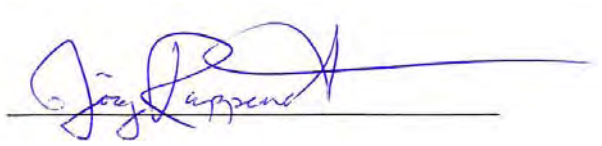
CERTIFICATION OF EVIDENCE:

As Chief Executive Officer of Fort Frances Power Corporation, I certify that, to the best of my knowledge, the evidence filed in this Application is accurate and that it is consistent with Chapter Two of the Ontario Energy Board's Filing Requirements for Transmission and Distribution Applications issued on July 17, 2013 and Chapter Five of the Ontario Energy Board's Filing Requirements for Transmission and Distribution Applications issued on March 28, 2013.



Joerg S. Ruppenstein,

President and Chief Executive Officer

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Executive Summary

Fort Frances Power Corporation is a corporation incorporated pursuant to the Ontario Business Corporations Act, with its head office in the Town of Fort Frances, Ontario. The Applicant carries on the business of distributing electricity within the municipal boundaries of the Town of Fort Frances. Fort Frances Power Corporation is governed by a six member Board of Directors whose mandate is overseeing the management of the corporation's business and affairs, including planning, risk identification and risk management, succession planning, and foremost, the stewardship of the 1905 Agreement between the Town of Fort Frances and the owner of hydroelectric generating station assets along the Rainy River in Fort Frances, Ontario.

Fort Frances Power Corporation's Board of Directors are selected to provide guidance and leadership and each possess a depth of experience and knowledge pertaining to:

- Distribution of electrical services and operations;
- Public, municipal and government relations;
- Business management including finance, accounting and risk management;
- Educational and occupational health and safety;
- Stewardship of the Historical 1905 Agreement Power Agreement.

The current Board of Directors have served the Fort Frances Power Corporation for a combined total of over one hundred and fifty years and their knowledge and commitment to our corporation and community is highly valued.

Fort Frances Power Corporation's priorities are defined in its Vision, Mission and Values Statements as per the following:

Vision Statement:

The Fort Frances Power Corporation strives to be a model distributor of electricity and supplier of supporting energy services, with excellence in customer focus, operational efficiency and community partnership.

Mission Statement:

To deliver electricity and provide supporting energy services safely, reliably and cost-effectively, in support of the well being of our community, for whom we exist.

Our Values

We Value Safety:

We believe that all work related injuries can be prevented, and we are committed to the safety of our employees and the general public. We are committed to providing our employees with all of the proper resources that allow them to work safely, as well as to ensure that public safety is maintained.

We Value Our Community and the 1905 Historic Power Agreement:

We believe that the well being of the 1905 Historic Power Agreement, held between the owner of the local generating station assets and the residents and small businesses of the Town of Fort Frances, is vital to the future success of our community. We are committed on behalf of the residents and small businesses of the Town of Fort Frances, to administer the agreement and to ensure that the rights and obligations of the agreement are upheld, thereby ensuring its longevity. We also believe we are stewards of our environment and, as such, we will conduct our business in an environmentally responsible manner. We believe that our success hinges largely on the success of our community.

We Value Our Employees:

We believe that our employees are the cornerstone of our organization. We are committed to providing a safe, healthy and fulfilling work environment for our employees, with fair

remuneration, sound management and opportunities for learning and professional development.

We Value Customer Focus:

We are committed to offering superior customer services in a manner that responds to customer preferences and needs. We are committed to providing our customers with a safe and reliable supply of electricity at the lowest rates possible that do not undermine our viability.

We Value Operational Efficiency:

We believe in the philosophy of "Continuous Improvement", and we will strive to continuously improve the efficiency of our operation and processes. We will continually improve by harvesting the innovation of our employees and by integrating technology into our business.

Unique Characteristic:

"(O)n the execution and delivery of this Agreement, and in further consideration of the covenants and requirements hereinafter contained and of the special agreement to supply power or electrical energy to the Town of Fort Frances..,"

(Excerpt from the 1905 Agreement between Ontario and Minnesota Power Company (Limited), 1905 (Can.), c. 139."



View of the Town of Fort Frances prior to dam construction.

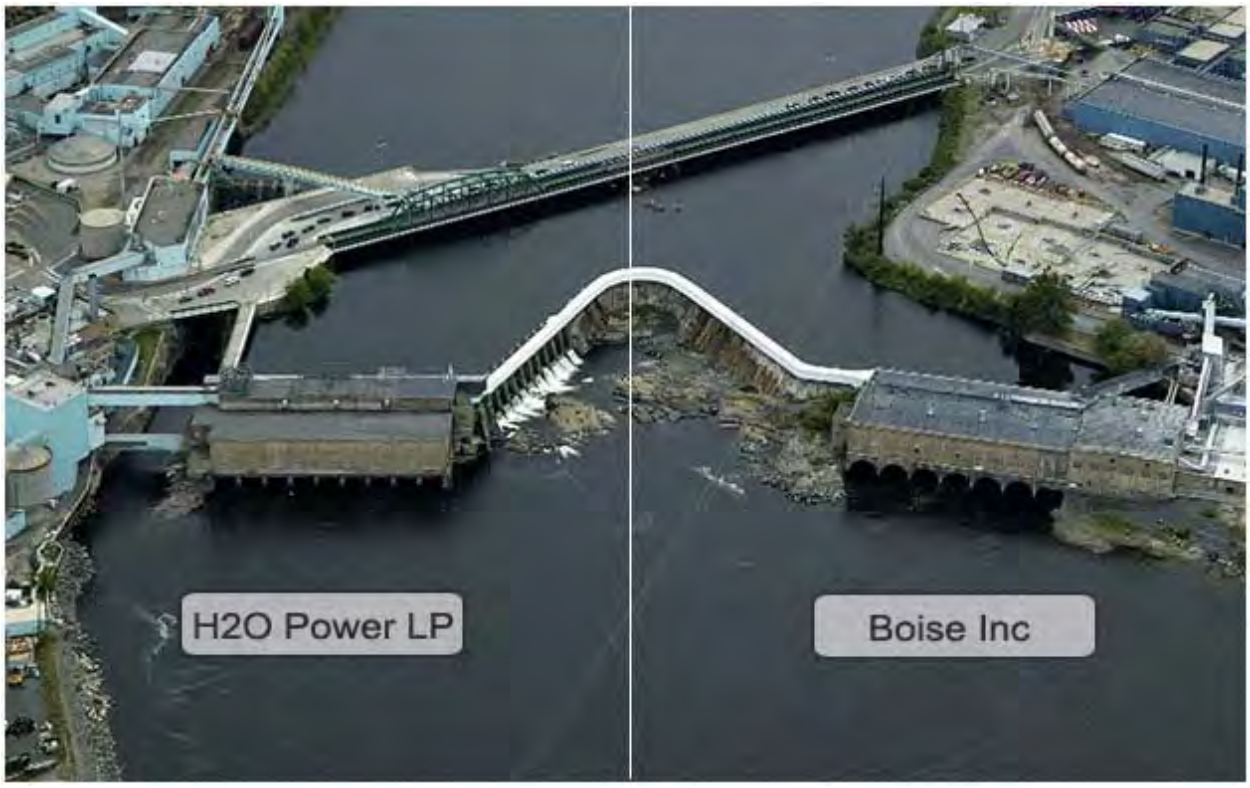
FFPC is unique as its customers, precisely the residents and small businesses of the Town of Fort Frances, are beneficiaries of a historic 1905 Agreement entered into between the Town and the local pulp and paper mill. The 1905 Agreement obligates the mill owner, or more precisely today, the owner of the generation assets on the Rainy River (currently H2O Power LP

("H2O")), to provide to the Town of Fort Frances, in perpetuity, 4,000 horsepower (2.984 Megawatts) at $14 per horsepower per annum (0.21416 cents per kilowatt hour) "for municipal purposes and for public utilities" [*Fort Frances v Boise Cascade Canada Ltd*., [1983] 1 SCR 171 at 184].



Dam Construction, 1908 (Courtesy of Fort Frances Museum and Cultural Centre)

The 1905 Agreement is filed as a physical bilateral contract with the IESO and represents a financial obligation of H2O. Essentially, for 2.984 Megawatts, which represents approximately 25% of the power purchases of FFPC, H2O pays to the IESO the additional costs of power above 0.21416 cents per kilowatt hour, and the IESO credits FFPC for that amount. FFPC in turn credits its customers who, in effect, pay a blended commodity rate reflecting the benefit of the 1905 Agreement. The amount of the benefit currently exceeds $2.2 million annually.



Costs associated with maintaining the benefits of the 1905 Agreement are not insignificant. The accounting and billing for the benefits of the 1905 Agreement is labour-intensive. Further, given the value of the 1905 Agreement to the residents of the Town of Fort Frances, and the corresponding cost to the owner of the generation assets on the Rainy River, the 1905 Agreement is under constant attack from the owner of the generation assets. Finally, the existence of the 1905 Agreement and the manner in which it reduces the price for power paid by the residents of the Town of Fort Frances, relative to other ratepayers in the Province, often requires that FFPC be given unique and specific treatment by government policy, regulation and legislation so as to preserve its benefits.

The specific cost elements associated with maintaining and enforcing the 1905 Agreement are best dealt within the context of this cost of service rate rebasing application. FFPC has unique costs incurred to:

1. Ensuring regulatory and policy changes uphold the benefit of the 1905 Agreement;
2. Enforcing the 1905 Agreement as against the various owners, from time to time, of the generation assets tied to the 1905 Agreement; and
3. Working with the IESO and the owner of the generation assets and internally to ensure that residents obtain a blended rate which reflects the financial benefit of the 1905 Agreement to which they are entitled.

FFPC's leadership focus is the safeguarding of the 1905 agreement and to ensure that the benefits entitled to the citizens and small businesses of the Town of Fort Frances are properly distributed. The 'not-for-profit' status under which FFPC operates, is in direct response to the safeguarding of the agreement and it underpins our corporate structure. FFPC's capital structure of zero debt and investment equity, position the corporation well to operate under a rate minimization strategy.

The 1905 agreement is paramount to the future of the Town of Fort Frances, whose economic decline is similar to that of many other small northern pulp and paper communities. The leadership of FFPC uphold the firm belief that despite the economic issues within the Town of Fort Frances, the ratepayers of the Fort Frances Power Corporation deserve fair and just electricity rates that support an efficient, modern distribution company that provides excellent customer service and high system reliability and safety.

Under the Renewed Regulatory Framework for Electricity (RRFE), FFPC realizes that the stewardship of the historical agreement is of foremost importance to our customers, yet at the same time, the agreement places unique cost burdens on FFPC, unlike other distributors. FFPC believes its individual utility circumstance must be fully recognized when cost performance is compared to that of other LDC's. As such, operating, maintenance and administrative (OM&A) costs must be adjusted to reflect the unique operating circumstances, such that subsequent

performance scores and ranking reflects “apples-to-apples” comparisons. FFPC would be pleased to work with the Board, as well as with the Pacific Economics Group, to refine FFPC’s performance scores, including the assignment of FFPC’s Stretch Factor and Efficiency Cohort grouping.

In summation, FFPC believes that its current performance scores derived from historic RRR reported OM&A cost data are flawed, as they include costs associated with the upkeep of the 1905 Historical Power Agreement, as well as costs associated with the upkeep and operation of a High Voltage Transformer Station, which prior to 2012 was improperly classified as a Distribution Station. FFPC’s OM&A costs at face value essentially support three distinct business functions, which in essence have increased FFPC’s scope. As such, synergies from this arrangements are best measured at the Total Bill level which encompass FFPC’s unique circumstances and operating strategy.

Overall Business Strategy

Fort Frances Power Corporation (FFPC) is a not-for-profit local distribution company whose sole shareholder is the Corporation of the Town of Fort Frances. FFPC operates under a rate minimization philosophy that balances necessary distribution system maintenance and re-investment, to provide our customers with safe and reliable service at the lowest possible rates. FFPC currently has no debt and operates at a zero percent rate-of-return, in the best interest of its consumers.

FFPC's current rates are set under the Third Generation Incentive Rate Mechanism effective May 1, 2013 until April 30, 2014. FFPC last conducted a complete rebasing of its distribution rates in 2006 under Board file number EB-2005-0366. As a non-profit driven utility, FFPC was able to forego adjusting its distribution rates as regularly scheduled for the 2010 rate year, as financial obligations were still adequately met. Similarly, FFPC formally requested to further defer its rate rebasing for the 2011, 2012 and 2013 rate years.

Distribution revenues collected over the course of the 2012 did not adequately meet FFPC's financial obligations and a subsequent material operating deficit was recorded at yearend. As such, current distribution rates no longer adequately support FFPC's financial viability, due largely to the long passage of time since FFPC's last rebasing, as well as due to increased business demands placed on distributors. Therefore, FFPC is pursuing to rebase its rates for the 2014 rate year, to realign its revenue stream with the projected business needs over the 2014 to 2018 planning period. FFPC plans to operate on the adjusted distribution rates until such time that operating deficits are again realized, at which time FFPC will pursue conducting a subsequent Cost of Service Application. As FFPC operates as a not-for-profit corporation, any excess revenue collected will be used solely for the purpose of accumulating appropriate operating and capital reserves, to mitigate future rate increases.

Balanced Scorecard Approach

FFPC developed this rate application with a focus on achieving the performance outcomes established for electricity distributors under the Renewed Regulatory Framework for Electricity, in regards to Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.

The balanced scorecard partially aligns to the four performance outcomes established by the Ontario Energy Board (the "OEB" or the "Board") in its report on the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "RRFE Report")* and its draft Regulatory Performance Scorecard. Under Section 5.3 of FFPC's DS Plan, FFPC has included a comprehensive analysis of its performance with respect to Board Staff's recommended July 2013 scorecard, as well as with respect to FFPC's own internal key performance measures. The following table illustrates Board Staff's July 2013 recommended scorecard, which was provided to distributors during their 2014 COS Orientation Session.

Table 1.1: Board Staff's July 2013 Recommended Scorecard

Performance Outcomes	Performance Categories	Measures (new in red)	
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	Connection of New LV Services (DSC s7.2, RRR s2.1.4.1.1)	
		Appointments: Scheduled (DSC s7.3, RRR s2.1.4.1.2)	
		Appointments: Met (DSC s7.4, RRR s2.1.4.1.3)	
		Telephone Accessibility (DSC s7.6, RRR s2.1.4.1.5)	
	Customer Satisfaction	1st Contact Resolution	
		Billing Accuracy	
		Results of Distributor Customer Satisfaction Survey	
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.	Safety	Public Safety measure	
	System Reliability	System Average Interruption Duration Index (Loss of Supply) (RRR s2.1.4.2.2)	
		System Average Interruption Frequency Index (Loss of Supply) (RRR s2.1.4.2.4)	
		Customer-Specific Reliability measure	
	Asset Management	System Plan Execution measure	
	Overall cost performance	Total Cost Benchmarking	Adjustment to Costs for High Voltage Service
			Adjustment to Costs for Low Voltage Service
			Efficiency Assessment (Cohort Ranking I through V)
			Econometric Benchmarking (Cost performance significantly superior, average, or significantly inferior) Unit cost/peer group benchmarking (Quintile Ranking 1 through 5)
		OM&A Cost	per Customer
			per kWh Delivered
			per Circuit Km of Line
		Net Plant Cost	per Customer
			per kWh Delivered
			per Circuit Km of Line
Public Policy Responsiveness Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Government Directive on Conservation & Demand Management	Net Annual Peak Demand Savings (MW)	
		Net Cumulative Energy Savings (GWh)	
	Connection of Renewable Generation	% of CIA Completed for Renewable Generation Facilities >10 kW within the applicable timeline prescribed by Ontario Regulation 326/09 made under the Electricity Act, 1998	
		MicroFit Connection measure	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	
		Profitability: Regulatory Return on Equity (RRR 2.1.5.6)	

Customer Focus:

FFPC is dedicated to providing services in a manner that responds to customer preferences. During the summer of 2013, FFPC conducted an extensive customer satisfaction survey, which was instrumental in gauging satisfaction, identifying improvement opportunities and assessing future customer needs and wants. The feedback gathered has helped to shape our capital expenditures, as well as to devote considerable operational resources towards customer preferences, over the 2014 to 2018 planning period. FFPC is committed to aligning our service offerings with the needs of our customer base. Customer clearly identified that they:

1. Are overall very satisfied with the reliability of electricity supplied and with the services provided by FFPC.
2. Feel the most important electricity-related issue facing them is the overall cost of electricity.
3. Would like FFPC to have the ability of contacting them directly, regarding important events such as power interruptions.
4. Would like FFPC to transition to true calendar based monthly billing.
5. Would like a choice of receiving paper or electronic bills.
6. Would like access to monthly billing information.
7. Are very interested in learning more about how they can conserve electricity.
8. Would like FFPC to educate them on industry topics of interest

In response to the needs and requests identified, FFPC will be transitioning to true monthly billing, offering a choice of electronic or paper billing, as well as granting access to consumption and billing data in 2014. FFPC also plans to invest in a mass customer contact system, as well as in an outage management system. These investments will enable FFPC to improve its ability to manage outages, as well as improve FFPC's ability to communicate directly with customers

regarding important events such as outages. With the help of this technology, customer communication will be conducted in an efficient and effective manner.

A new "Technical Customer Services Representative" position is also planned to be included in FFPC's organizational structure, to focus on continued customer and stakeholder engagement activities, as well as to support the annual execution of newly developed asset management and capital planning processes. FFPC also plans to utilize the position to conduct customer education campaigns in local schools, at tradeshows, town hall meetings, as well as through standard media outlets. As a result of FFPC's customer engagement activities, $58,000 has been dedicated towards capital expenditures to address customer needs, which represents 1.6% of all planned capital expenditures over the 2014 to 2018 planning period. In addition to this, FFPC will be devoting significant staff resources towards the implementation of the above mentioned projects and initiatives.

FFPC was not able to officially launch its CDM efforts until the fall of 2011, due to the delay in the availability essentially all conservation program offerings. As such, FFPC achieved only a small portion of its mandated targets that year. Since the delayed launch, FFPC has experienced good uptake on many program offerings. FFPC has managed to surpass provincial results with respect to the peak reduction category and has greatly closed the gap with respect to volumetric reduction. FFPC's 2012 OPA Final CDM report states that FFPC has achieved 49.4% of its 3.64 GWh demand reduction target, and 21% of its 0.61 MW peak reduction target. FFPC anticipates improved results for the 2013 program year. The most notable 2013 CDM achievement is the community-wide conversion of conventional street lights to LED street lights. Approximately 80% of all fixtures have been replaced with LED style fixtures at the time of preparing this rate application. FFPC expects to meet its mandated CDM targets by the end of 2014. As a point of interest, the following picture illustrates the difference in lighting quality of Front Street being lit with newly installed LED fixtures, compared to traditional lighting along

the side of the street, along the scenic waterfront, which is the international boundary between Canada and USA. Notice the bright white street compared to the yellow scenic walkway.



Front Street LED Street Lighting Retrofit

Operational Effectiveness:

FFPC has a long history of utilizing technology and employee innovation to improve on its operational efficiency and effectiveness. The newly developed asset management and capital planning processes, which have been built on the foundation of a first class GIS system, are instrumental in enabling FFPC to realize sustainable long term saving through improved asset lifecycle management, long term planning capabilities and data driven decision making. Over the 2014 to 2018 planning horizon, FFPC estimates that it will realize $455,757 is cost savings through its improved asset oversight, enabling good planning. The savings are expected to be achieved without negatively impacting system reliability or quality related objectives. Of the

$3,522,205 in total planned capital expenditures, $2,775,966 or 78.8 %, are related to managing the lifecycle of existing assets. This underscores the importance and value of the newly developed GIS based asset management and capital planning processes. FFPC is also planning to invest an additional $72,500, towards achieving more effective financial oversight of its operation, through the deployment of a Financial Information System. The additional business operational efficiency investments represent 2.1% of the total planned capital expenditures. FFPC believes that its strategy will deliver value for money, and as such is in the best interest of all of FFPC's customers.

Public Policy Responsiveness:

FFPC is committed to delivering on its mandated service obligations. This plan addresses the following mandated service obligations: the Elimination of Long Term Load Transfers; to support the Connection of Renewable Generation facilities; to facilitate the implementation of a Smart Grid; and to achieve the mandated CDM Targets through the delivery of CDM Programs.

FFPC has dedicated $371,739 of capital expenditures towards the mandated elimination of Long Term Load Transfer arrangements, through the expansion of its distribution feeders. The expansions will resolve the long standing issue and will actually improve FFPC's ability to accommodate large scale Renewable Generation facilities, unlock access to approximately 25% of FFPC's undeveloped distribution service territory, promote the overall economic well being of the community by encouraging growth, as well as enable the benefits of the 1905 Historic Power Agreement to be distributed to the LTLT customers.

Over the last few years, FFPC conducted a system wide analysis to assess the capability of connecting renewable generation onto its distribution feeders, as well as directly to its greater than 50 kV transformer station. Practical constraints were identified that greatly limit the

overall generation capacity that FFPC's distribution system can accommodate. FFPC has developed a seven year plan towards the implementation of Renewable Enabling Improvements, that will increase the potential renewable generation capacity from 1.3 MW to 10.8 MW. All renewable enabling improvements are towards control and protection upgrades at FFPC's greater than 50 kV transformer station "Fort Frances MTS". The station upgrades will also allow for individual feeder performance monitoring to be conducted, from which operating constraints are derived. Constraints are currently set to error on the side of caution as no feeder monitoring is in place. The OPA has confirmed that FFPC's plan is aligned with regional needs developments. FFPC has planned $229,673 in renewable enabling improvements, of which $167,000 (4.7% of total capital expenditures) is planned over the 2014 to 2018 planning period. FFPC has previously incurred $62,673 throughout 2012 and 2013 in renewable enabling improvement expenditures, for which it is also seeking recovery.

FFPC currently does not have any planned investments specific to only achieving Smart Grid objectives; however, other planned investments such as the Renewable Generation Enabling Improvements achieve many of Smart Grid objectives. The proposed transformer station improvements will support Smart Grid objectives under the Power System Flexibility, Customer Control and Adaptive Infrastructure categories. The improvements will also allow for the sharing of information with regional stakeholders.

Financial Performance:

FFPC operates under a rate minimization philosophy with the objective of balancing investment needs, with providing customers with a safe and reliable supply of electricity at the lowest possible rates. FFPC has taken a "just-in-time" asset replacement approach, under which assets will be replaced on a proactive manner as they approach their high probability of failure zone in their lifecycle, as established by FFPC's asset management and capital planning processes. FFPC's strategy is to pace investments according to the rate at which its asset base is

deteriorating, so as to maintain long term perpetual viability. This ensures that the asset base as a whole is not driven to failure (end-of-life), at which time enormous reinvestment would be required. This application has been built on this premise, and as such, the planned investments contained within it are essential to maintain FFPC's long term viability.

FFPC's asset management and capital planning processes are instrumental in ensuring that savings from operational effectiveness are sustainable. FFPC has a good track record of wise spending, and has kept its cost base to a bare minimum in the best interest of ratepayers. Over the period 2006 to 2012 (2005 is base year), the average annual percentage OM&A increase of the electrical distribution industry in Ontario that was required to meet changing business demands was 29.7% (based on OEB Yearbooks). Over this period, FFPC's average annual percentage OM&A increase was 21.9%. If FFPC would have kept pace with OM&A expenditures relative to the demands of industry, FFPC's customer would have incurred $581,303 in additional expense. The savings are largely attributed to FFPC's approach of adjusting its business needs on a reactive basis, upon the numerous industry changes that occurred between 2005 and 2012 reaching their "steady state". FFPC credits its staff and service providers for enduring significantly intensified short term workloads, which were necessary to implement the multitude of sector changes.

The current level of effort exerted by FFPC's staff is not sustainable, and as such, FFPC is realigning its revenue requirement to fund additional resources (the addition of a Technical Customer Service Representative to staff, as well as more necessary services from third party service providers including Human Resources, Legal and IT expertise). To help offset funding additional resources, FFPC is projecting to realize $455,757 in sustainable cost savings over the 2014 to 2018 planning period, without negatively impacting the reliability or efficiency of its distribution system. The savings are attributed to the implementation of the newly developed asset management and capital planning processes. The processes have given FFPC improved oversight of its entire asset base managed, at the individual asset level, thereby enabling

precise data driven decision making and long range planning. Improved decision making will result in optimizing investment needs to support the right investments at the right time.

Application Background

Fort Frances Power Corporation (FFPC) filed a 2006 EDR Cost of Service Application, EB-2005-0366 with the Board on September 30, 2005. Since then, FFPC has filed annual Incentive Regulation Mechanism ('IRM") applications and a stand-alone Smart Meter Prudence Application. The impact of the each application is summarized in the table below.

Directive from 2006 Cost of Service Application (EB-2005-0366):

The Board prescribed a revenue requirement to be recovered through distribution rates and charges of $1,436,628, including a credit amount of $76,162 for the recovery of Regulatory Assets. The Board decision indicated a review and disposal of Account 1508, 2005 OEB dues would be considered at a later time. The Board also prescribed that a separate sub-class for USL be created, which was completed in 2006.

Table 1.2: Impact of IRM Applications

Date of Board Approval	Board File Number	Application Type	Approved Revenue and Revenue Increase
April 12, 2006	EB-2005-0366	EDR Cost Application	$1,436,628
April 12, 2007	EB-2007-0529	IRM	.9 % price cap adjustment
March 14, 2008	EB-2007-0885	IRM	1.1% price cap adjustment
March 10, 2009	EB-2008-0228	IRM	1.3 % price cap adjustment
April 20, 2010	EB-2009-0264	IRM	.3 % price cap adjustment
April 14, 2011	EB-2010-0128	IRM	.3 % price cap adjustment
April 19, 2012	EB-2011-0146	IRM	.88% price cap adjustment
November 12, 2012	EB-2012-0327	Smart Meter Prudence Review	$350,000 Incremental revenue
April 4, 2013	EB-2012-0083	IRM	.48% price cap adjustment

With the RRFE Report, the Board is applying a performance-based approach to regulation. FFPC is working to adopt this format and will continue to respond to customer preferences, enhance distributor productivity and promote innovation. FFPC's 2014 Cost of Service Application supports the four outcomes established by the Board:

- **Customer Focus:**
  - Services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness:**
  - Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- **Public Policy Responsiveness**:
  - Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board) and;
- **Financial Performance**:
  - Financial viability is maintained; and savings from operational effectiveness are sustainable.

Specifically, Fort Frances Power Corporation believes that this application is necessary to re-align distribution rates in order to recover its revenue deficiency of $413,881 in support of the following key drivers:

- FFPC is departing from its "Maintenance" mode of operation and is entering a major capital "Rebuild" mode of operation over the 2014 to 2018 planning horizon, as outlined

in the Distribution System Plan (DS Plan) in Exhibit 2. FFPC is planning invest a total of $2,775,966 in capital expenditures towards managing the lifecycle of its asset base over the 2014 to 2018 planning horizon, to keep pace with asset deterioration. FFPC's asset base as a whole, has surpassed its optimum target of 50% remaining useful service life, with an overall remaining useful life of 41.4%, with respect to the adopted useful life of asset classes as per FFPC's asset management process. With respect to the Typical Useful Life (TUL) values established in the Kinectrics Report", FFPC's overall remaining useful life of its asset base would be reduced to 33.4% The newly developed asset management and capital planning processes have given FFPC enhanced oversight and understanding of its asset base, at the individual asset level. The results obtained from FFPC's first formal asset lifecycle analysis has prompted FFPC to transition to intensified capital reinvestments, as the current rate of capital reinvestment is not keeping pace with rate of asset deterioration. FFPC will experience somewhat of a "tidal wave" affect over the next 20 years, as a disproportionately large number of assets will surpass the end of their useful service life, due to FFPC's entire distribution system being rebuilt over a ten year window from the mid-1970s to mid-1980s. FFPC requires this increased revenue to fund sustaining the lifecycle of its asset base, such that it is not undermined.

- FFPC also requires additional revenue to support the operating costs that have increased in the eight year span since the 2006 EDR application, while year-over-year revenue increases (price cap adjustments) have averaged a modest 0.75%. While revenue increases were modest, FFPC embraced the multitude of industry changes that occurred over the 2006 to 2014 time frame, which have placed significantly increased burdens on distributors. While workloads increased significantly, FFPC was able to retain its existing staffing level up until now. Some of the more significant industry changes include accommodating renewable generation and conservation activities under the Green Energy and Green Economy Act, transition to Time-of-Use Billing, Rate Rebasing via the Cost of Service process, adapting work procedures and policies to meet

the requirements of Ontario Regulation 22/04 "Electrical Distribution Safety", implementing the new OEB Customer Service Rules, implementation of the LEAP program, preparation for the transition to IFRS accounting standards, implementation of HST, implementation of the Ontario Clean Energy Benefit, implementation of the Special Purpose Charge, implementation of Ontario One Call, as well as the development of Green Energy, Smart Grid, Conservation and Asset Management plans. FFPC is planning on adding a Technical Customer Service Representative to its staff in 2014, who will be actively involved with all consumer engagement activities, such as conducting surveys and delivering consumer education campaigns. Other core job responsibilities include supporting the annual administration of FFPC's asset management process and assistance in all planning activities. Simply put, FFPC requires increasing its operating revenue to remain a viable business entity to be able to continue to meet industry demands. FFPC has a good track record of delivering value for money for its consumers. The additional revenue will be used to fund the addition of a Technical Customer Service Representative, as well as to ensure that FFPC has all of the necessary resources and skill sets to continue to deliver electricity and provide supporting energy services safely, reliably and cost-effectively, in support of the well being of our community, for whom we exist.

Key Elements of the Application

Revenue Requirement

FFPC is requesting the approval of rates effective May 1, 2014 to recover a revenue requirement of $1,989,765 which includes a revenue deficiency of $459,007 as set out in Exhibit 6, Tab 1, Schedule 1; the schedule of proposed rates is set out in Exhibit 8, Schedule 6;

The revenue requirement, compared to the 2006 approved service revenue requirement as shown in Table 1.3 below, represents an increase of $422,744 compared to the 2006 approved service revenue requirement.

Table 1.3: Fort Frances Power Corporation Base Revenue Proposal

Description	2006 Board Approved	2014 Test Year Proposed	Increase	Increase %
Reporting Basis	Old CGAAP	New CGAAP		
OM & A Expenses	$1,001,346	$1,657,650	$656,304	66%
Depreciation	$319,136	$197,074	-$122,062	-38%
Interest	$139,394	$135,041	-$4,353	-3%
Return on Equity - Target	$0	$0	$0	0%
PILs	$30,983	$0	-$30,983	-100%
Reg Asset Adjustment	$76,162			
Service Revenue Requirement	**$1,567,021**	**$1,989,765**	**$422,744**	**27%**
Revenue Offsets	$130,393	$103,033		0%
Base Revenue Requirement	**$1,436,628**	**$1,886,732**	**$450,104**	**31%**

FFPC's primary customer focus, based on the 2013 customer survey, is to deliver long term sustainable rate minimization or in other words to minimize consumer cost. FFPC is a not-for-profit LDC that operates under a rate minimization philosophy and continually strives to operate in the most cost efficient manner, in the best interest of consumers. FFPC is very conscious; however, that the sole focus on rate or cost reductions can undermine system reliability, safety and modernization, if the distribution system and assets are allowed to

deteriorate due to inadequate levels of reinvestment. FFPC plans to utilize its newly developed asset management and capital planning processes to enable rigorous data driven decision making and effective long range planning. This will ensure that investment decisions will allow FFPC to operate in the most efficient, cost effective manner, delivering customer value for money, without undermining service reliability or quality, as well as providing long term rate stability.

System Reliability

FFPC has a good track record of providing its customers with a reliable supply of electricity. In recent history, FFPC's overall distribution system performance (including Loss of Supply), outperformed industry, as per OEB yearbook data. With respect to industry standard performance measures SAIDI and SAIFI, FFPC was able to outperform industry six out of the last seven years. Although FFPC is pleased with its distribution system reliability, FFPC is continually seeking ways to improve performance and as such has recently implemented several successful strategies to minimize customer outages.

Historically, FFPC's most frequent cause of customer outages (and subsequent trouble calls) were related to animal contacts on overhead transformers, causing current limiting devices to be activated (fuses) to clear the faults. In 2007, FFPC completed retrofitting all of its overhead transformers with animal guards which has greatly reduced animal contacts. FFPC's overall distribution system reliability is also greatly affected by the reliability of FFPC's transmission supply. In the past, transmission network switching in the Fort Frances area resulted in FFPC momentarily losing the transmission supply to its transformer station, resulting in a power outage across its entire customer base. FFPC has worked with Hydro One Networks to change the supply configuration to its transformer station. In the fall of 2013, HONI reconfigured FFPC's supply, such that it now is a dedicated feed that is not impacted by regional transmission

system switching. These improvements will result in significant distribution system reliability improvements to the benefit of FFPC's customers in the future.

Since 2008, FFPC conducts annual outage root cause analyses. FFPC's top three contributing causes, to overall customer outage hours over the period 2008 to 2012 are: Loss of Supply (78.3%), Adverse Weather (10.3%) and Equipment Failures (7.2%).

Transformer and switch failures are the highest contributors to equipment failures which result in unplanned outages. FFPC's asset management process has identified that approximately 18% of the entire transformer population will reach the end of their suggested forty (40) year useful service life by 2018. The aging transformer fleet aligns with the results of the outage cause analysis, which identified transformer failures as being the most frequent equipment failure resulting in customer interruptions. As such, transformer replacements have a significant impact on FFPC's 2014 - 2018 DS Plan, as FFPC has allocated $1,007,541 towards end-of-life replacements, which represents 28.6% of all planned capital investments.

Table 1.4 FFPC's Reliability Statistics

Service Reliability Indicators
2008 - 2012

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
SAIDI	3.770	6.633	0.597	0.090	0.302	0.987	0.384	0.597	0.090	0.302
SAIFI	1.770	2.401	0.310	0.210	0.296	0.791	0.401	0.310	0.210	0.296

	5 Year Historical Average	
SAIDI	2.278	0.472
SAIFI	0.997	0.402

Billing Accuracy and Bill Presentment

FFPC's customers have requested a desire to access billing data online and to transition to true monthly billing. The transition will improve customer budgeting and historic consumption comparisons. FFPC has transitioned all metered customers to Smart Meter technology and will implement a web presentment tool in 2014 which will be available to all rate classes including GU over 50 kW customers. FFPC has always billed our customers monthly, but will now bill on the actual true calendar month consumption. As many of the Town of Fort Frances citizens are retired and are on monthly pension plans, the standardization of one bill at approximately the same time every month will improve customer budgeting and payment convenience.

Since its last cost of service application, FFPC has also responded to directives from the Minister of Energy to connect renewable generation, implement Time-of-Use billing and Ontario Clean Energy Benefit, changes to the HST on customer charges, introduce customer service measures for low-income customers and provide emergency financial assistance to low-income customers. FFPC has also complied with the requirements under the *Ontario One-Call Act* put into legislation in 2012 to mandate utility and infrastructure locates across Ontario. These costs are included in ongoing system operation and maintenance costs.

Budget Directives and Assumptions

FFPC made a concentrated effort to refine and improve its budgeting process. Advancements in record keeping and cost reporting and review have improved FFPC's business plan. This process has also been significantly enhanced by FFPC's newly developed Asset Management and Capital Planning processes, which have enabled capital, maintenance and operating budgets to be based on the results of rigorous data driven processes. It is important to note that future budgets are based on current cost, and as such have not been adjusted to reflect the impact of inflation.

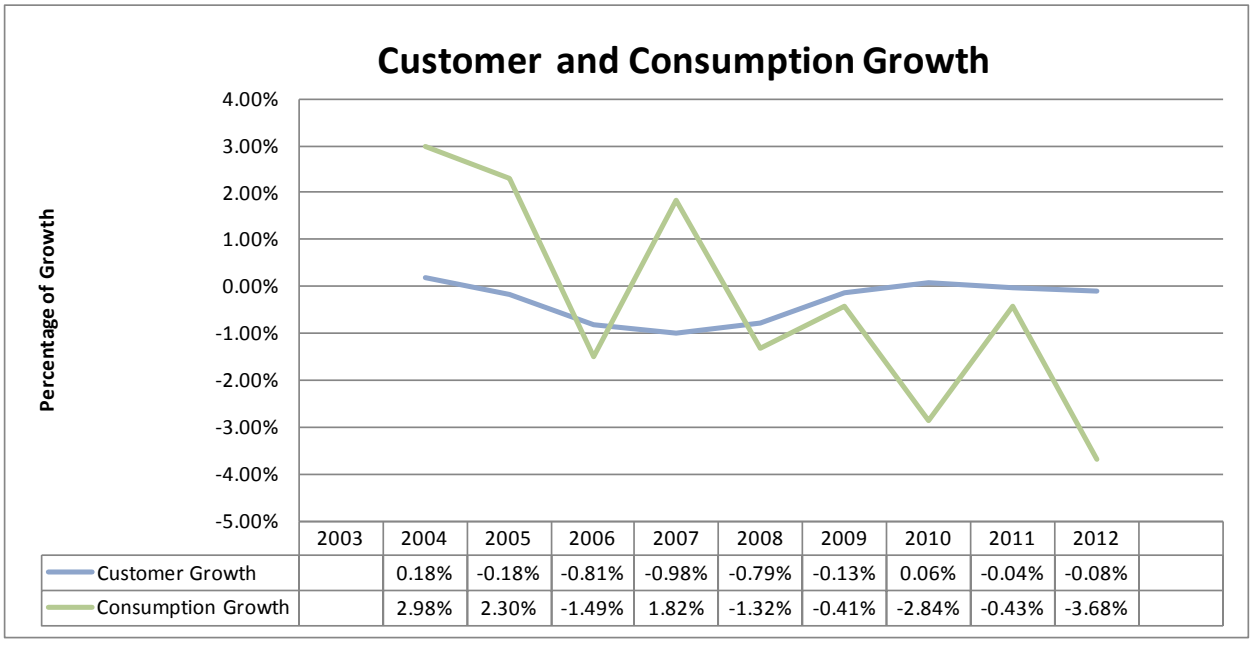
In the 2014 Test year, FFPC has included projected increases to wages and salaries due to incremental progression for unionized employees and to adjust for pending negotiated inflationary increases.

Load Forecast Summary and Economic Overview

The Town of Fort Frances and its municipal boundaries define the distribution service territory of FFPC. The Town of Fort Frances' major employer is Resolute Forest Products, who manufactures paper products and formerly provided Kraft Pulp to neighbouring paper mills. Resolute Forest Product has curtailed its operations to below one-third of its original capacity due to unfavourable market conditions and as such, the future of its operations is unknown. The plant currently only employs approximately 25% of the original staff complement at the peak of its operation.

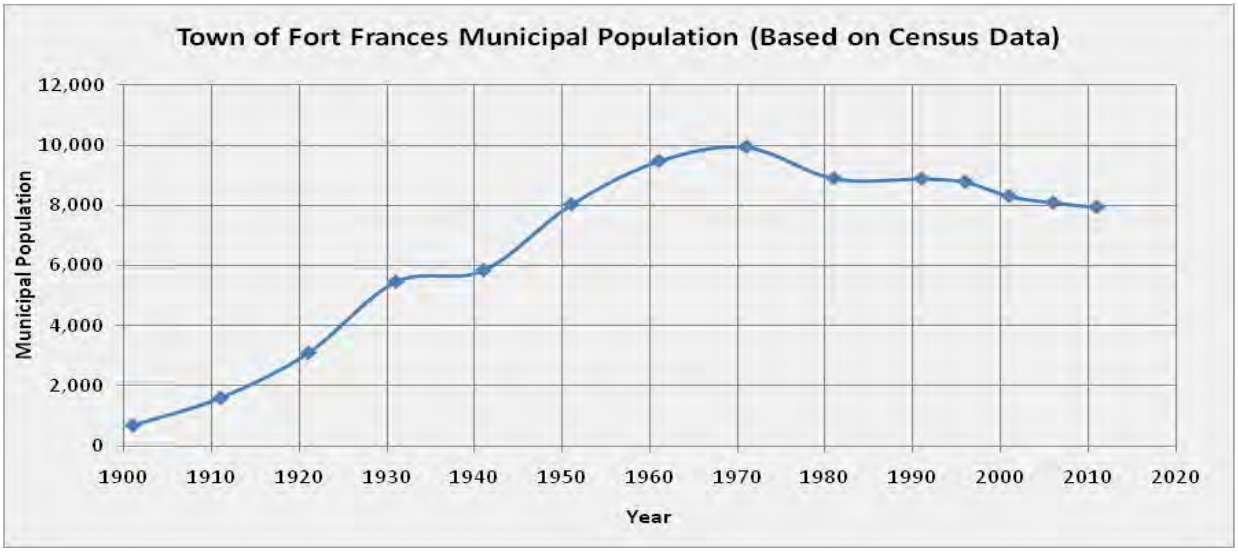
As employment opportunities are lost, the Town of Fort Frances faced reductions in its population by approximately twenty percent over the last forty years, similar to many other small pulp and paper industry based communities across Canada. FFPC's customer base has declined slightly as shown in the table below:

Table 1.5: Customer and Consumption Growth



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	
Customer Growth		0.18%	-0.18%	-0.81%	-0.98%	-0.79%	-0.13%	0.06%	-0.04%	-0.08%	
Consumption Growth		2.98%	2.30%	-1.49%	1.82%	-1.32%	-0.41%	-2.84%	-0.43%	-3.68%	

Table 1.6: Town of Fort Frances Municipal Population based on Census Data:



Load Forecast and Summary

FFPC's forecasted energy consumption for the 2014 Test Year is 3,930,999 kWh lower than its 2006 Board Approved kWh as provided in Table 1.6, Load and Customer Growth – 2014 Test Year vs. 2006 Board Approved. FFPC's forecasted customer base has declined -148, which is equivalent to a decrease of 3% over 2006 Board Approved customer count. This illustrates a gradual decline in FFPC's customer base over the last eight years.

Table 1.7: Load and Customer Growth – 2014 Test Year vs. 2006 Board Approved.

Description	2006 Board Approved	2014 Test Year Proposed	Increase / (Decrease)	Increase / (Decrease) %
Billed kWh	82,092,018	78,161,019	(3,930,999)	-5%
Number of Customers	4,917	4,769	(148)	-3%

FFPC used a multivariate regression model to forecast the weather normalized load forecast for the 2014 Test Year. The "total system weather normalized purchased energy forecast" is developed based on a multivariate regression model that includes historical load, weather, days in the month and customer data.

Rate Base and Capital Planning

Summary of Majors Driver of the DS Plan

FFPC utilized its newly developed Asset Management and Capital Planning Processes to develop its 2014 to 2018 Capital Investment Plan. Since 2005, FFPC has dedicated tremendous resources towards the development of a Geographical Information System (GIS). The system has been invaluable for building the foundation of the data driven DS Plan. The system was heavily relied upon for the lifecycle analysis of essentially all assets owned, including General Plant assets.

Lifecycle sustaining capital reinvestments account for $2,775,966 or 78.8% of the total $3,522,205 capital investment need identified for the 2014 to 2018 planning period. FFPC conducted detailed asset category specific lifecycle needs analyses to determine expenditure requirements. The detailed analysis summaries are included as part of the DS Plan throughout Section 5.3. It is very important to note that FFPC's entire distribution system, including its greater than 50 kV transformer station, was rebuilt from the mid 1970s to mid 1980s, and as such FFPC operated in a "maintenance mode" for several decades, with relatively low requirements for capital reinvestments. Many assets owned are now aging and will be approaching the end of their useful service life over the course of the 2014 to 2018 planning period. The oncoming "tidal wave" of aging assets has prompted FFPC to transition from its maintenance mode to a capital rebuild mode, to keep pace with the disproportionately high volume of assets posing high risk of failure.

FFPC's asset management process has established a total asset replacement cost of $24,379,821 for all existing assets managed, based on FFPC's current cost structure (relative to 2013 pricing). Based on FFPC's adopted useful life values for each asset category, the average

annual reinvestment needed to keep pace with asset deterioration is $618,169. The overall % remaining useful life (relative to FFPC's adopted UL and replacement cost) of all assets owned is 41.4%. FFPC's long term objective is to maintain a 50% "Remaining UL" profile where possible, to smooth long term spending requirements in the interest of long term rate stability. As such, FFPC's optimal annual capital reinvestment rate is $618,169, which is necessary to sustain the lifecycles of all assets managed, thereby keeping pace with asset deterioration.

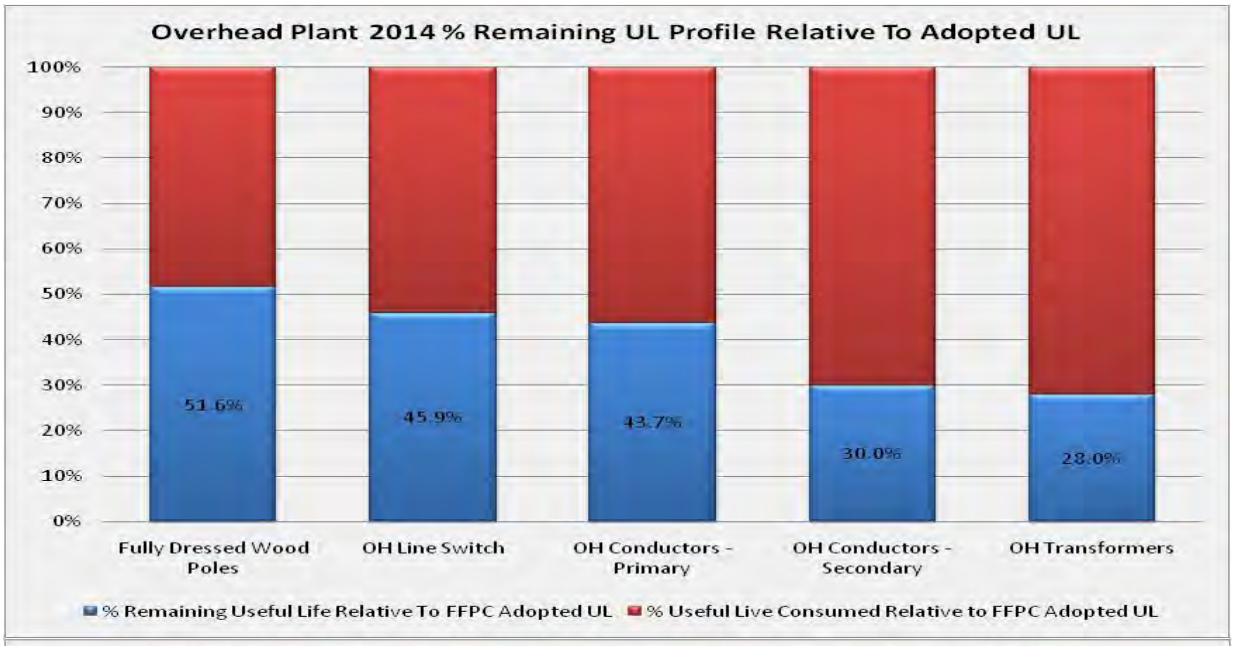
FFPC recognizes; however, that its' Greater than 50 kV Transformer Stations is made up of a small number of high priced assets that require sporadic long term investments. FFPC has therefore adjusted its optimal annual reinvestment rate, to only include costs related to necessary Transformer Station reinvestments over the planning period, as identified through the asset management process (lifecycle analyses). As such, FFPC's optimal annual reinvestment rate is $568,857 and FFPC has targeted an average annual reinvestment rate of $555,193. The actual average reinvestment rate is approximately 2.5% lower than the optimal; as FFPC is targeting overall cost reductions of 2.5% attributed to improved planning and asset oversight. The following table summarizes FFPC's assets, Useful Life Assessments, Investment Boundaries and Capital Budget Allocations for all lifecycle sustaining reinvestments:

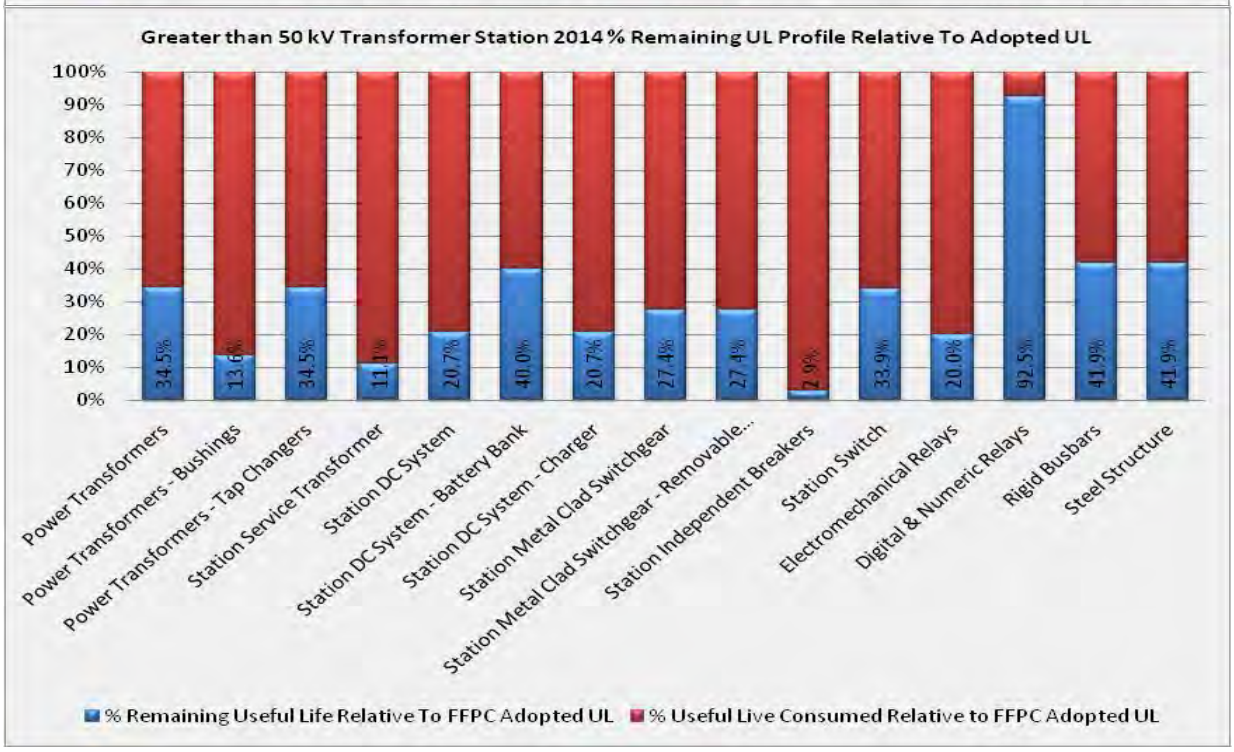
Table 1.8: FFPC Asset Summary, Useful Life Assessment, Investment Boundaries and Capital Budget Allocations

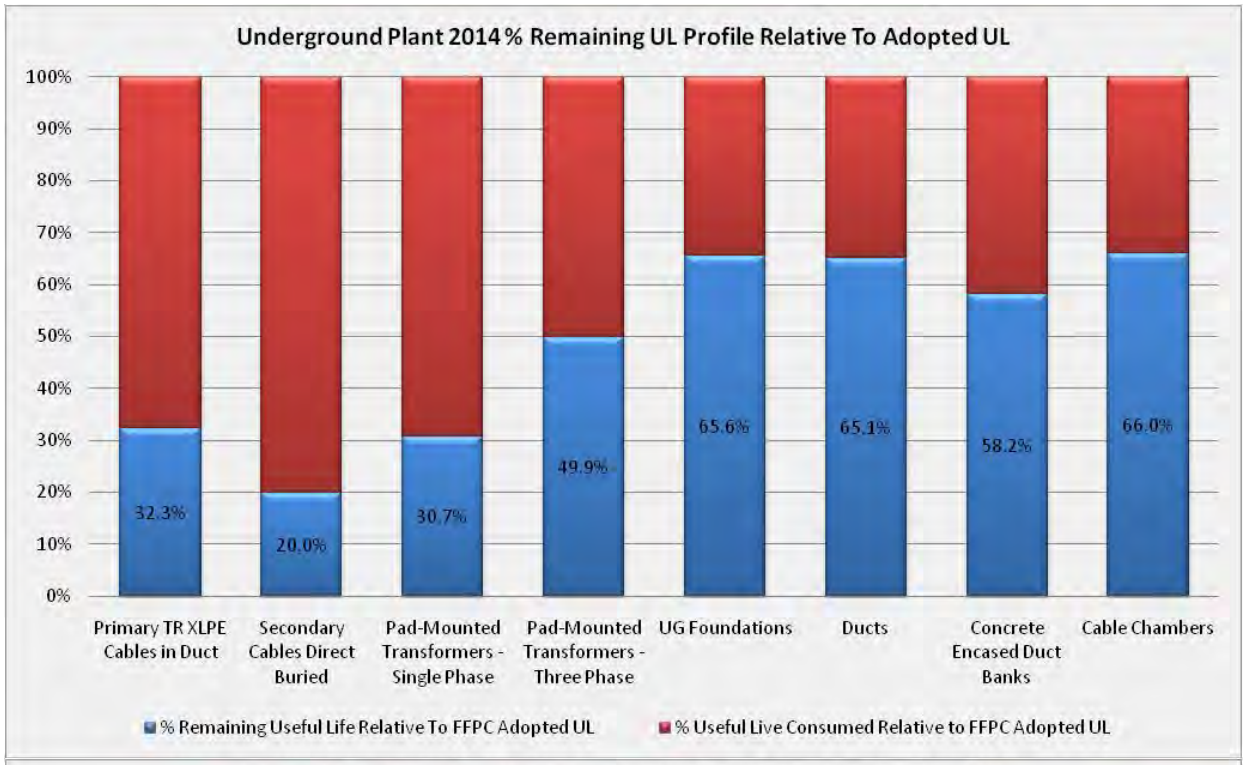
		Asset Details			FFPC Assets			Kinectrics Useful Life			Useful Life Assessment					Reinvestment Needs Assessment					Capital Budget Allocation		
Parent*	#	Category| Component | Type			Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to Kinectrics TUL	% Remaining Useful Life Relative to Kinectrics TUL	Remaining Useful Life Relative to FFPC Adopted UL	% Remaining Useful Life Relative To FFPC Adopted UL	Total Replacement Cost of Asset Group	Average Annual Reinvestment Need Based on Kinectrics Min UL	Average Annual Reinvestment Need Based on Kinectrics TUL	Average Annual Reinvestment Need Based on Kinectrics Max UL	Average Annual Reinvestment Need Based on FFPC Adopted UL	Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2044 to 2018)	% of Total DS Plan Capital Expenditures
OH	1	Fully Dressed Wood Poles	Overall		1776	Each	21.79	35	45	75	45	23.21	51.58%	23.21	51.6%	$ 5,850,761	$ 167,165	$ 130,017	$ 78,010	**$ 130,017**	$ 679,638	$ 135,928	19.3%
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	2	Fully Dressed Concrete Poles	Overall		N/A			50	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	3	Fully Dressed Steel Poles	Overall		N/A			60	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	4	OH Line Switch (Expressed as sets of 3 Phase Switches)			35	Each	24.34	30	45	55	45	20.66	45.90%	20.66	45.9%	$ 254,409	$ 8,480	$ 5,654	$ 4,626	**$ 5,654**	$ 32,500	$ 6,500	0.9%
	5	OH Line Switch Motor			N/A			15	25	25													
	6	OH Line Switch RTU			N/A			15	20	20													
	7	OH Integral Switches			N/A			35	45	60													
	8	OH Conductors	Primary Conductor		224.2	km	33.77	50	60	75	60	26.23	43.72%	26.23	43.7%	$ 676,409	$ 13,528	$ 11,273	$ 9,019	**$ 11,273**	$ -	$ -	0.0%
			Secondary Conductor		114.8	km	28.00	25	35	40	40	7.00	20.00%	12.00	30.0%	$ 1,033,603	$ 41,344	$ 29,532	$ 25,840	**$ 25,840**	$ 50,000	$ 10,000	1.4%
	9	OH Transformers			629	Each	28.79	30	40	60	40	11.21	28.02%	11.21	28.0%	$ 2,751,265	$ 91,709	$ 68,782	$ 45,854	**$ 68,782**	$ 491,617	$ 98,323	14.0%
	10	OH Shunt Capacitor Banks			N/A			25	30	40													
	11	Reclosers			N/A			25	40	55													
TS & MS	12	Power Transformers	Overall		2	Each	38.00	30	45	60	58	7.00	15.56%	20.00	34.5%	$ 1,930,575	$ 64,352	$ 42,902	$ 32,176	**$ 33,286**	$ -	$ -	0.0%
			Bushing		12	Each	38.00	10	20	30	44	0.00	0.00%	6.00	13.6%	$ 68,351	$ 6,835	$ 3,418	$ 2,278	**$ 1,553**	$ -	$ -	0.0%
			Tap Changer		2	Each	38.00	20	30	60	58	0.00	0.00%	20.00	34.5%	$ 1,127,792	$ 56,390	$ 37,593	$ 18,797	**$ 19,445**	$ -	$ -	0.0%
	13	Station Service Transformer			1	Each	40.00	30	45	55	45	5.00	11.11%	5.00	11.1%	$ 8,544	$ 285	$ 190	$ 155	**$ 190**	$ -	$ -	0.0%
	14	Station Grounding Transformer			N/A	Each		30	40	40													
	15	Station DC System	Overall		2	Each	23.00	10	20	30	29	0.00	0.00%	6.00	20.7%	$ 85,439	$ 8,544	$ 4,272	$ 2,848	**$ 2,946**	$ -	$ -	0.0%
			Battery Bank		2	Each	9.00	10	15	15	15	6.00	40.00%	6.00	40.0%	$ 51,263	$ 5,126	$ 3,418	$ 3,418	**$ 3,418**	$ 10,000	$ 2,000	0.3%
			Charger		2	Each	23.00	20	20	30	29	0.00	0.00%	6.00	20.7%	$ 34,176	$ 1,709	$ 1,709	$ 1,139	**$ 1,178**	$ 22,000	$ 4,400	0.6%
	16	Station Metal Clad Switchgear	Overall		11	Each	45.00	30	40	60	62	0.00	0.00%	17.00	27.4%	$ 845,844	$ 28,195	$ 21,146	$ 14,097	**$ 13,643**	$ -	$ -	0.0%
			Removable Breaker		11	Each	45.00	25	40	60	62	0.00	0.00%	17.00	27.4%	$ 205,053	$ 8,202	$ 5,126	$ 3,418	**$ 3,307**	$ -	$ -	0.0%
	17	Station Independent Breakers			1	Each	67.00	35	45	65	69	0.00	0.00%	2.00	2.9%	$ 138,411	$ 3,955	$ 3,076	$ 2,129	**$ 2,006**	$ 150,000	$ 30,000	4.3%
	18	Station Switch			5	Each	41.00	30	50	60	62	9.00	18.00%	21.00	33.9%	$ 68,351	$ 2,278	$ 1,367	$ 1,139	**$ 1,102**	$ -	$ -	0.0%
	19	Electromechanical Relays			34	Each	36.00	25	35	50	45	0.00	0.00%	9.00	20.0%	$ 131,576	$ 5,263	$ 3,759	$ 2,632	**$ 2,924**	$ -	$ -	0.0%
	20	Solid State Relays			N/A	Each		10	30	45													
	21	Digital & Numeric Relays			8	Each	1.50	15	20	20	20	18.50	92.50%	18.50	92.5%	$ 56,390	$ 3,759	$ 2,819	$ 2,819	**$ 2,819**	$ -	$ -	0.0%
	22	Rigid Busbars			3	Each	36.00	30	55	60	62	19.00	34.55%	26.00	41.9%	$ 42,719	$ 1,424	$ 777	$ 712	**$ 689**	$ -	$ -	0.0%
	23	Steel Structure			1	Each	36.00	35	50	90	62	14.00	28.00%	26.00	41.9%	$ 136,702	$ 3,906	$ 2,734	$ 1,519	**$ 2,205**	$ 25,000	$ 5,000	0.7%
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			N/A			60	65	75													
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			N/A			20	25	25													
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			N/A			20	25	30													
	27	Primary Non-TR XLPE Cables in Duct			N/A			20	25	30													
	28	Primary TR XLPE Cables Direct Buried			N/A			25	30	35													

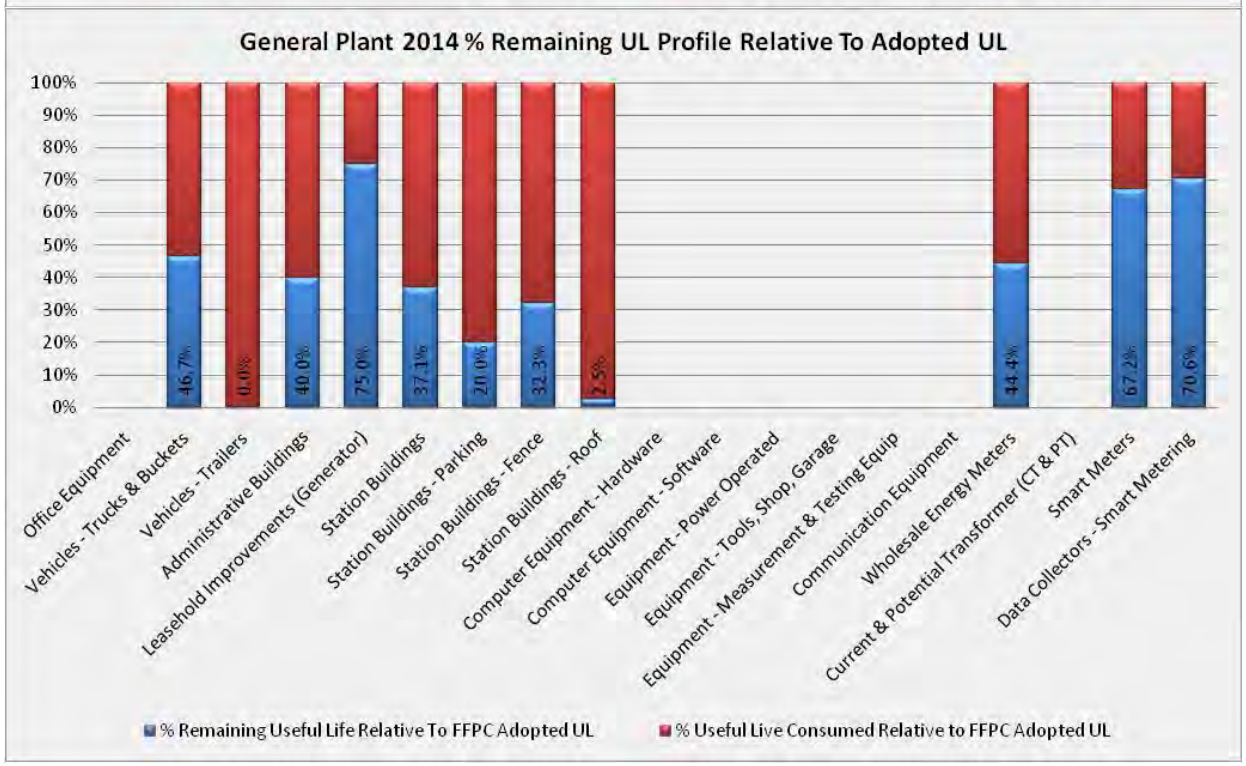
	29	Primary TR XLPE Cables in Duct		30.7	km	27.07	35	40	55	40	12.93	32.32%	12.93	32.3%	$ 931,695	$ 26,620	$ 23,292	$ 16,940	**$ 23,292**	$ 180,537	$ 36,107	5.1%
	30	Secondary PILC Cables		N/A			70	75	80													
	31	Secondary Cables Direct Buried		3.8	km	28.00	25	35	40	35	7.00	20.00%	7.00	20.0%	$ 68,366	$ 2,735	$ 1,953	$ 1,709	**$ 1,953**	$ 10,000	$ 2,000	0.3%
	32	Secondary Cables in Duct		N/A			35	40	60													
	33	Network Transformers	Overall	N/A			20	35	50													
			Protector	N/A			20	35	40													
	34	Pad-Mounted Transformers	Single Phase	215	Each	27.70	25	40	45	40	12.30	30.74%	12.30	30.7%	$ 2,218,967	$ 88,759	$ 55,474	$ 49,310	**$ 55,474**	$ 368,761	$ 73,752	10.5%
			Three Phase	38	Each	20.05	25	40	45	40	19.95	49.87%	19.95	49.9%	$ 808,033	$ 32,321	$ 20,201	$ 17,956	**$ 20,201**	$ 147,163	$ 29,433	4.2%
	35	Submersible/Vault Transformers		N/A			25	35	45													
	36	UG Foundation		170	Each	27.52	35	55	70	80	27.48	49.97%	52.48	65.6%	$ 814,956	$ 23,284	$ 14,817	$ 11,642	**$ 10,187**	$ -	$ -	0.0%
	37	UG Vaults	Overall	N/A			40	60	80													
			Roof	N/A			20	30	45													
	38	UG Vault Switches		N/A			20	35	50													
	39	Pad-Mounted Switchgear		N/A			20	30	45													
	40	Ducts		23.5	km	27.95	30	50	85	80	22.05	44.10%	52.05	65.1%	$ 322,801	$ 10,760	$ 6,456	$ 3,798	**$ 4,035**	$ -	$ -	0.0%
	41	Concrete Encased Duct Banks		1.9	km	33.46	35	55	80	80	21.54	39.16%	46.54	58.2%	$ 712,998	$ 20,371	$ 12,964	$ 8,912	**$ 8,912**	$ -	$ -	0.0%
	42	Cable Chambers		5	Each	20.40	50	60	80	60	39.60	66.00%	39.60	66.0%	$ 35,000	$ 700	$ 583	$ 438	**$ 583**	$ -	$ -	0.0%
S	43	Remote SCADA		N/A			15	20	30													
General Plant	1	Office Equipment		Unknown	Each	Unknown	*5*	*10.0*	*15*	15	Unknown	Unknown	Unknown	Unknown	$ 60,000	$ 12,000	$ 6,000	$ 4,000	**$ 4,000**	$ 15,000	$ 3,000	0.4%
	2	Vehicles	Trucks & Buckets	7	Each	8.00	*5*	*10.0*	*15*	15	2.00	20.00%	7.00	46.7%	$ 801,000	$ 160,200	$ 80,100	$ 53,400	**$ 53,400**	$ 328,000	$ 65,600	9.3%
			Trailers	2	Each	26.00	*5*	*12.5*	*20*	20	0.00	0.00%	0.00	0.0%	$ 75,000	$ 15,000	$ 6,000	$ 3,750	**$ 3,750**	$ 75,000	$ 15,000	2.1%
			Vans	N/A			*5*	*7.5*	*10*													
	3	Administrative Buildings		1	Each	45.00	*50*	*62.5*	*75*	75	17.50	28.00%	30.00	40.0%	$ 550,000	$ 11,000	$ 8,800	$ 7,333	**$ 7,333**	$ 65,000	$ 13,000	1.8%
	4	Leasehold Improvements (Generator)		1	Each	5.00	*20*	*20.0*	*20*	20	15.00	75.00%	15.00	75.0%	$ 86,122	$ 4,306	$ 4,306	$ 4,306	**$ 4,306**	$ -	$ -	0.0%
	5	Station Buildings	Station Buildings	2	Each	39.0	*50*	*62.5*	*75*	62	23.50	37.60%	23.00	37.1%	$ 368,375	$ 7,368	$ 5,894	$ 4,912	**$ 5,942**	$ 31,000	$ 6,200	0.9%
			Parking	1	Each	24.00	*25*	*27.5*	*30*	30	3.50	12.73%	6.00	20.0%	$ 5,000	$ 200	$ 182	$ 167	**$ 167**	$ -	$ -	0.0%
			Fence	1	Each	42.00	*25*	*42.5*	*60*	62	0.50	1.18%	20.00	32.3%	$ 22,500	$ 900	$ 529	$ 375	**$ 363**	$ -	$ -	0.0%
			Roof	2	Each	39.00	*30*	*30.0*	*30*	40	0.00	0.00%	1.00	2.5%	$ 30,000	$ 1,000	$ 1,000	$ 1,000	**$ 750**	$ -	$ -	0.0%
	6	Computer Equipment	Hardware	Unknown	Each	Unknown	*3*	*4.0*	*5*	5	Unknown	Unknown	Unknown	Unknown	$ 32,000	$ 10,667	$ 8,000	$ 6,400	**$ 6,400**	$ 35,500	$ 7,100	1.0%
			Software	Unknown	Each	Unknown	*2*	*3.5*	*5*	5	Unknown	Unknown	Unknown	Unknown	$ 76,000	$ 38,000	$ 21,714	$ 15,200	**$ 15,200**	$ -	$ -	0.0%
	7	Equipment	Power Operated	Unknown	Each	Unknown	*5*	*7.5*	*10*	7	Unknown	Unknown	Unknown	Unknown	$ 7,000	$ 1,400	$ 933	$ 700	**$ 1,000**	$ 30,500	$ 6,100	0.9%
			Stores	N/A			*5*	*7.5*	*10*													
			Tools, Shop, Garage Equip.	Unknown	Each	Unknown	*5*	*7.5*	*10*	10	Unknown	Unknown	Unknown	Unknown	$ 10,000	$ 2,000	$ 1,333	$ 1,000	**$ 1,000**			
			Measurement & Testing Equip	Unknown	Each	Unknown	*5*	*7.5*	*10*	8	Unknown	Unknown	Unknown	Unknown	$ 65,000	$ 13,000	$ 8,667	$ 6,500	**$ 8,125**			
	8	Communication	Towers	N/A			*60*	*65.0*	*70*													
			Wireless	Unknown	Each	Unknown	*2*	*6.0*	*10*	10	Unknown	Unknown	Unknown	Unknown	$ 9,600	$ 4,800	$ 1,600	$ 960	**$ 960**	$ -	$ -	0.0%
	9	Residential Energy Meters		N/A			*25*	*30.0*	*35*													
	10	Industrial/Commercial Energy Meters		N/A			*25*	*30.0*	*35*													
	11	Wholesale Energy Meters		2	Each	5.00	*15*	*22.5*	*30*	9	17.50	77.78%	4.00	44.4%	$ 18,000	$ 1,200	$ 800	$ 600	**$ 2,000**	$ -	$ -	0.0%
	12	Current & Potential Transformer (CT & PT)		479	Each	Unknown	*35*	*42.5*	*50*	40	Unknown	Unknown	Unknown	Unknown	$ 85,262	$ 2,436	$ 2,006	$ 1,705	**$ 2,132**	$ 12,500	$ 2,500	0.4%
	13	Smart Meters		3966	Each	4.92	*5*	*10.0*	*15*	15	5.08	50.76%	10.08	67.2%	$ 650,543	$ 130,109	$ 65,054	$ 43,370	**$ 43,370**	$ 16,250	$ 3,250	0.5%
	14	Repeaters - Smart Metering		N/A			*10*	*12.5*	*15*													
	15	Data Collectors - Smart Metering		7	Each	5.00	*15*	*17.5*	*20*	17	12.50	71.43%	12.00	70.6%	$ 17,972	$ 1,198	$ 1,027	$ 899	**$ 1,057**	$ -	$ -	0.0%
Totals															$ 24,379,820.51	$ 1,144,782	$ 739,250	$ 519,907	**$ 618,169**	**$ 2,775,966**	**$ 555,193**	**78.8%**

The following graphs illustrate the percentage of remaining and consumed useful life of FFPC's asset base, by asset category (Please note that the age profiles for Equipment categories are not known at this time, and as such they have been left blank. FFPC plans to obtain the missing age profile data over the course of the planning horizon):



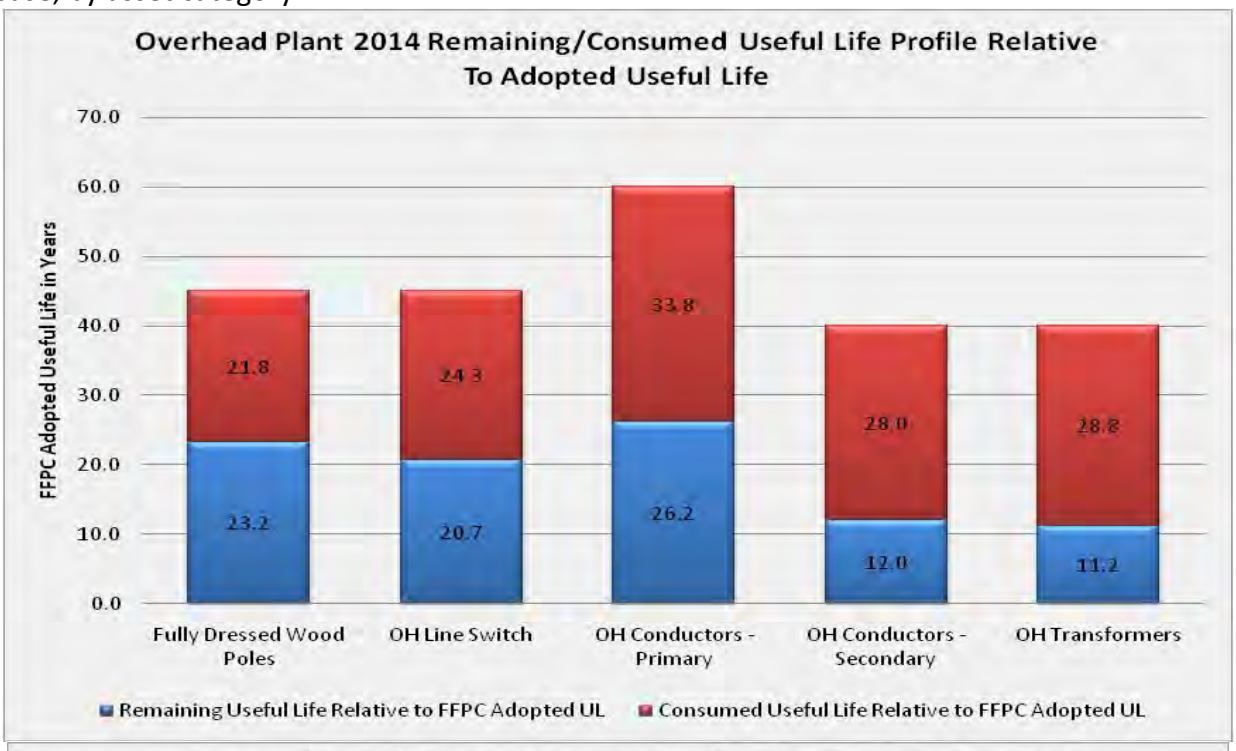


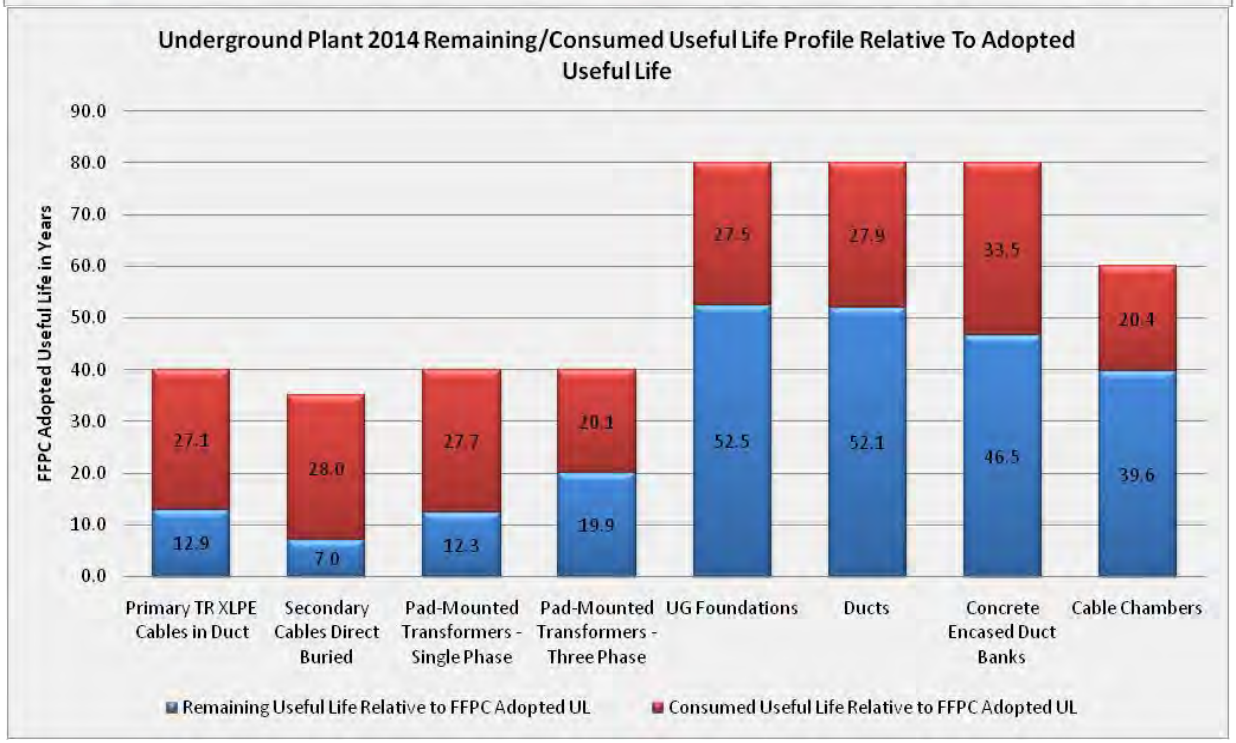


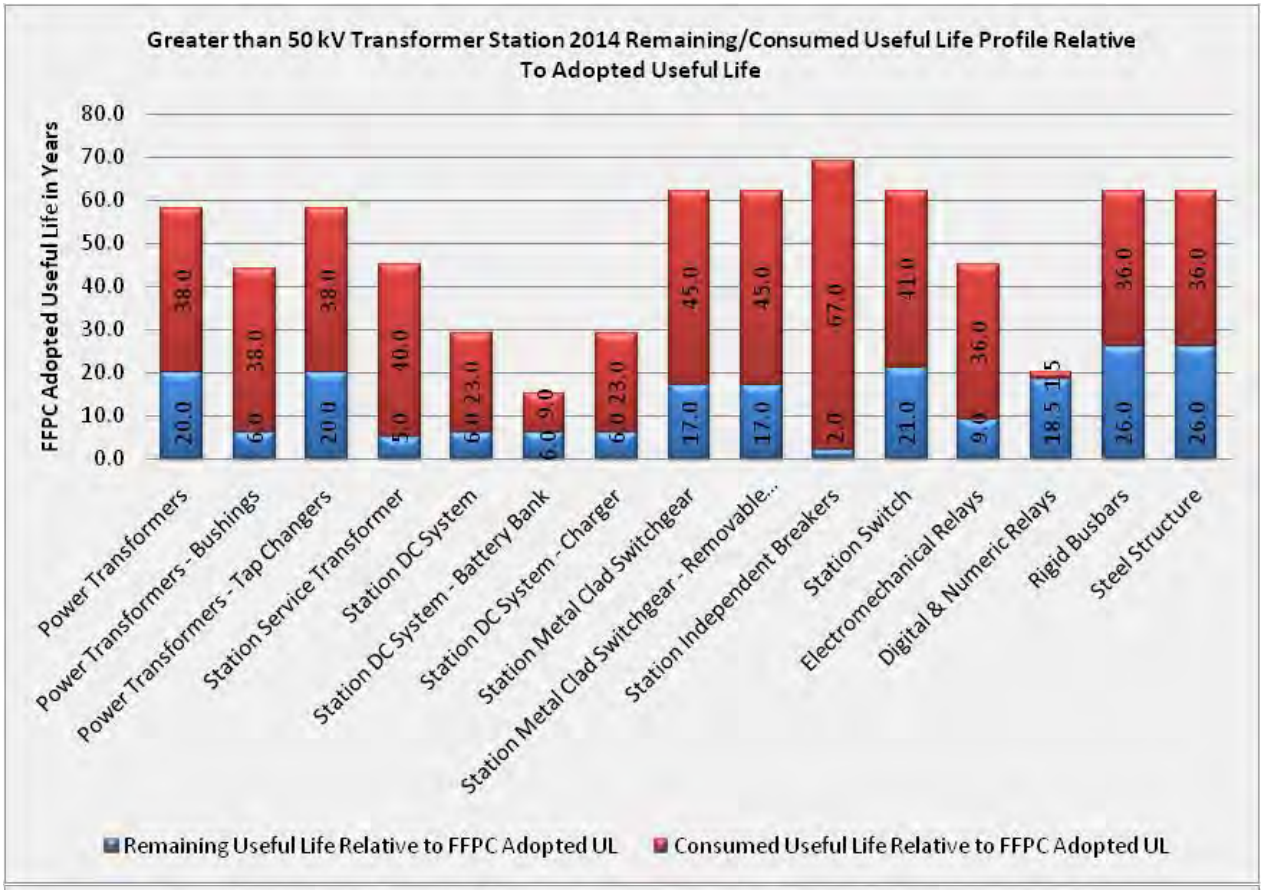


Note: Age profiles are not yet available for the Equipment related categories.

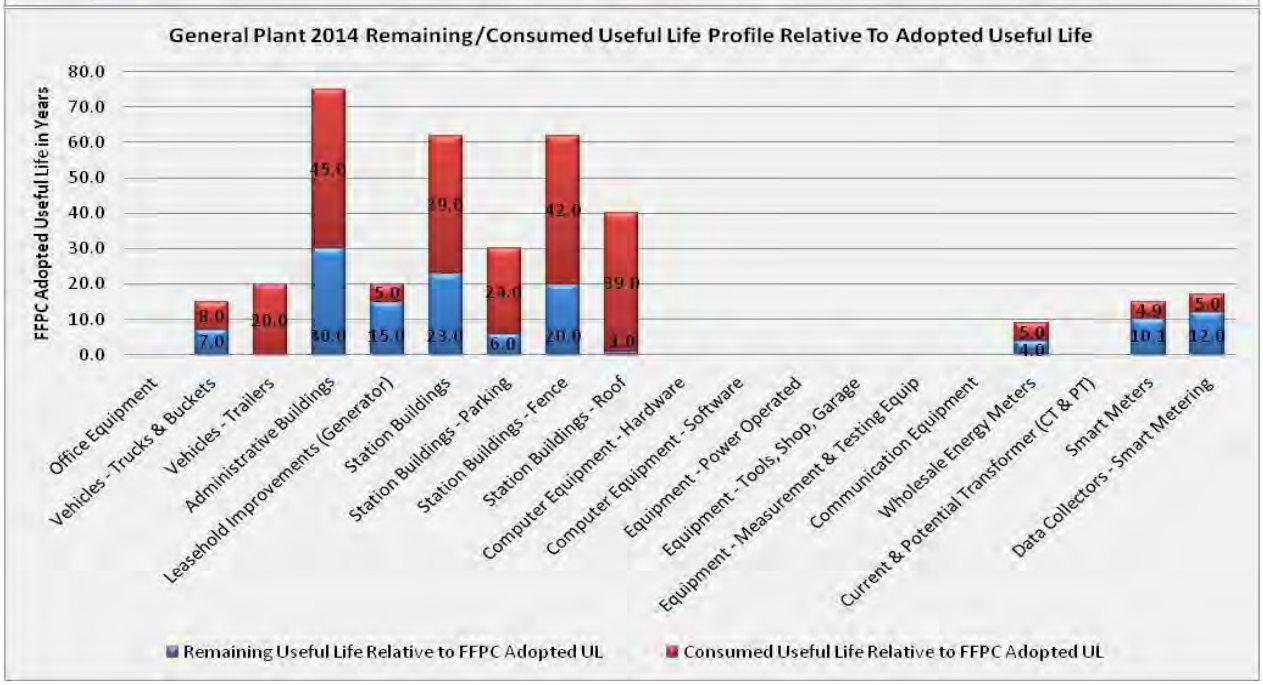
The following graphs illustrate the remaining and consumed years of useful life of FFPC's asset base, by asset category:







1



2

3 Note: Age profiles are not yet available for the Equipment related categories.

As previously mentioned, lifecycle sustaining capital reinvestments account for $2,775,966 (78.8%) of the total $3,522,205 capital investment needs identified, for the 2014 to 2018 planning period. The remaining portion of capital investment needs is required to address meeting other business objectives, addressing mandatory or legal obligations, as well as accommodating stakeholder needs (customer engagement activities). FFPC has allocated the following capital: $149,500 to address meeting business objectives, $538,739 to address meeting mandated service obligations, as well as $58,000 in response to customer preference. For filing purposes, FFPC has grouped and summarized its investment projects according to Section 5.1.1 of the Chapter 5 filing guide. As such, the following table summarizes the planned capital investments by category and investment driver, as well as the subsequent table illustrates the relative importance of each investment driver based on its percentage of the total planned investments:

Table 1.9: FFPC 2014 to 2018 Planned Capital Expenditures by Investment Category

FFPC 2014 to 2018 Planned Capital Expenditures by Investment Category							
Investment Category	**Investment Driver**	**2014**	**2015**	**2016**	**2017**	**2018**	**2014 - 2018 Total**
		Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Total Planned Expenditures
System Access	Mandated Service Obligations	$ 421,739	$ 40,000	$ 20,000	$ 45,000	$ 12,000	$ 538,739
	3rd Party Infrastructure Development	$ -	$ -	$ -	$ -	$ -	$ -
	Customer Service Requests	$ -	$ -	$ -	$ -	$ -	$ -
System Renewal	EOL - Failure	$ 20,568	$ 8,608	$ 8,608	$ 8,608	$ 8,608	$ 54,999
	EOL - Failure Risk	$ 231,009	$ 408,255	$ 471,723	$ 520,363	$ 350,116	$ 1,981,466
	EOL - Functional Obsolescence	$ -	$ -	$ -	$ -	$ -	$ -
	EOL - High Performance Risk	$ 2,000	$ 2,000	$ 24,000	$ 2,000	$ 2,000	$ 32,000
	EOL - Substandard Performance	$ -	$ -	$ -	$ -	$ -	$ -
System Service	Customer Preference	$ -	$ 15,000	$ -	$ 43,000	$ -	$ 58,000
	Obj - Imp Performance/Functionality	$ -	$ -	$ -	$ -	$ -	$ -
	Obj - Power Quality	$ -	$ -	$ -	$ -	$ -	$ -
	Obj - Reliability	$ 14,500	$ 87,000	$ 40,000	$ 15,000	$ 15,000	$ 171,500
	Obj - Safety	$ 34,500	$ -	$ -	$ -	$ -	$ 34,500
	Obj - System Efficiency	$ 4,000	$ -	$ -	$ -	$ -	$ 4,000
General Plant	Non-System Physical Plant	$ 78,000	$ 50,500	$ 50,000	$ 23,000	$ 51,500	$ 253,000
	Business Operation Efficiency	$ 2,500	$ 40,000	$ 30,000	$ -	$ -	$ 72,500
	Other Performance/Functionality	$ 2,500	$ -	$ -	$ -	$ -	$ 2,500
	System Cap / Maintenance Support	$ 9,000	$ 25,000	$ 16,000	$ 10,000	$ 259,000	$ 319,000
Total Annual Capital Budget		$ 820,316	$ 676,363	$ 660,331	$ 666,971	$ 698,224	$ 3,522,205

Table 1.10: FFPC 2014 to 2018 Planned Capital Expenditures by % Investment Driver

FFPC 2014 to 2018 Planned Capital Expenditures by % Investment Driver							
Investment Category	Investment Driver	**2014**	**2015**	**2016**	**2017**	**2018**	**2014 - 2018 Total**
		% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Total Planned Expenditures
System Access	Mandated Service Obligations	51.4%	5.9%	3.0%	6.7%	1.7%	15.3%
	3rd Party Infrastructure Development	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Customer Service Requests	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
System Renewal	EOL - Failure	2.5%	1.3%	1.3%	1.3%	1.2%	1.6%
	EOL - Failure Risk	28.2%	60.4%	71.4%	78.0%	50.1%	56.3%
	EOL - Functional Obsolescence	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	EOL - High Performance Risk	0.2%	0.3%	3.6%	0.3%	0.3%	0.9%
	EOL - Substandard Performance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
System Service	Customer Preference	0.0%	2.2%	0.0%	6.4%	0.0%	1.6%
	Obj - Imp Performance/Functionality	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Obj - Power Quality	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Obj - Reliability	1.8%	12.9%	6.1%	2.2%	2.1%	4.9%
	Obj - Safety	4.2%	0.0%	0.0%	0.0%	0.0%	1.0%
	Obj - System Efficiency	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%
General Plant	Non-System Physical Plant	9.5%	7.5%	7.6%	3.4%	7.4%	7.2%
	Business Operation Efficiency	0.3%	5.9%	4.5%	0.0%	0.0%	2.1%
	Other Performance/Functionality	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%
	System Cap / Maintenance Support	1.1%	3.7%	2.4%	1.5%	37.1%	9.1%
	Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

The following tables illustrate FFPC's total planned capital expenditures by Investment Category:

Table 1.11: FFPC 2014 to 2018 Planned Capital Expenditures by Investment Category

Investment Category	2014	2015	2016	2017	2018	2014 - 2018 Total
	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)
System Access	421.7	40.0	20.0	45.0	12.0	538.7
System Renewal	253.6	418.9	504.3	531.0	360.7	2068.5
System Service	48.5	142.0	60.0	58.0	15.0	323.5
General Plant	96.5	75.5	76.0	33.0	310.5	591.5
Total	820.3	676.4	660.3	667.0	698.2	3522.2
System O&M	24.3	13.0	7.1	7.8	2.5	54.7

Table 1.12: FFPC 2014 to 2018 Planned Capital Expenditures by % Investment Category

Investment Category	2014	2015	2016	2017	2018	2014 - 2018 Total
	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Total Planned Expenditures
% System Access	51.4%	5.9%	3.0%	6.7%	1.7%	15.3%
% System Renewal	30.9%	61.9%	76.4%	79.6%	51.7%	58.7%
% System Service	5.9%	21.0%	9.1%	8.7%	2.1%	9.2%
% General Plant	11.8%	11.2%	11.5%	4.9%	44.5%	16.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Of the total $3,522,205 in total planned capital expenditures over the 2014 to 2018 planning period, 58.7% are towards System Renewal, 16.3% are towards General Plant, 15.3% are towards System Access and 9.2% are towards System Service.

The "Kinectrics Asset Depreciation Study for the Ontario Energy Board" was of great assistance in the development of this DS Plan, as well as in the development of FFPC's Asset Management Process. FFPC

would like to give credit to the authors of the report for the valuable body of work, as well as to the OEB for having the foresight to undertake the project. The following table illustrates FFPC's 2014 to 2018 planned capital investments by asset class, as per the Kinectrics Report.

Table 1.13: FFPC 2014 - 2018 Capital Expenditure Summary By Kinectrics Asset Class

FFPC 2014 - 2018 Capital Expenditure Summary By Kinectrics Asset Class						
Kinectrics Asset Class	2014	2015	2016	2017	2018	2014 - 2018 Total
	Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Total Planned Expenditures
1 - Fully Dressed Wood Poles	$ 434,609	$ 134,928	$ 134,928	$ 134,928	$ 134,928	$ 974,319
4 - OH Line Switch	$ 32,500	$ -	$ -	$ -	$ -	$ 32,500
8 - OH Conductors	$ 11,180	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 59,180
9 - OH Transformers	$ 98,086	$ 104,894	$ 68,081	$ 129,709	$ 129,428	$ 530,197
Overhead Totals	**$ 576,375**	**$ 251,821**	**$ 215,009**	**$ 276,636**	**$ 276,355**	**$ 1,596,197**
12 - Power Transformers	$ -	$ -	$ -	$ -	$ -	$ -
13 - Station Service Transformer	$ -	$ -	$ -	$ -	$ -	$ -
15 - Station DC System	$ 2,000	$ 2,000	$ 24,000	$ 2,000	$ 2,000	$ 32,000
16 - Station Metal Clad Switchgear	$ -	$ -	$ -	$ -	$ -	$ -
17 - Station Independent Breakers	$ -	$ -	$ 150,000	$ -	$ -	$ 150,000
18 - Station Switch	$ -	$ -	$ -	$ -	$ -	$ -
19 - Electromechanical Relays	$ -	$ -	$ -	$ -	$ -	$ -
21 - Digital & Numeric Relays	$ 50,000	$ -	$ 20,000	$ -	$ -	$ 70,000
22 - Rigid Busbars	$ -	$ -	$ -	$ -	$ -	$ -
23 - Steel Structure	$ -	$ -	$ 25,000	$ -	$ -	$ 25,000
TS & MS Totals	**$ 52,000**	**$ 2,000**	**$ 219,000**	**$ 2,000**	**$ 2,000**	**$ 277,000**
29 - Primary TR XLPE Cables in Duct	$ 18,549	$ 36,609	$ 6,573	$ 79,915	$ 41,189	$ 182,835
30 - Secondary PILC Cables	$ -	$ -	$ -	$ -	$ -	$ -
31 - Secondary Cables Direct Buried	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 10,000
33 - Network Transformers	$ -	$ -	$ -	$ -	$ -	$ -
34 - Pad-Mounted Transformers	$ 36,142	$ 135,682	$ 115,999	$ 179,670	$ 48,430	$ 515,923

36 - UG Foundation	$ -	$ -	$ -	$ -	$ -	$ -
40 - Ducts	$ 27,000	$ -	$ -	$ -	$ -	$ 27,000
41 - Concrete Encased Duct Banks	$ -	$ -	$ -	$ -	$ -	$ -
42 - Cable Chambers	$ -	$ -	$ -	$ -	$ -	$ -
UG Totals	**$ 83,691**	**$ 174,292**	**$ 124,572**	**$ 261,585**	**$ 91,619**	**$ 735,758**
43 - Remote SCADA	$ -	$ 20,000	$ -	$ 45,000	$ 12,000	$ 77,000
G1 - Office Equipment	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 15,000
G2 - Vehicles	$ 50,000	$ 38,000	$ 40,000	$ -	$ 275,000	$ 403,000
G3 - Administrative Buildings	$ 11,000	$ 21,500	$ 15,000	$ 8,000	$ 9,500	$ 65,000
G4 - Leasehold Improvements (Generator)	$ -	$ -	$ -	$ -	$ -	$ -
G5 - Station Buildings	$ 5,000	$ 74,000	$ 5,000	$ 5,000	$ 4,000	$ 93,000
G6 - Computer Equipment	$ 19,500	$ 46,000	$ 21,000	$ 55,000	$ 1,000	$ 142,500
G7 - Equipment	$ 14,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 34,000
G8 - Communication	$ -	$ 35,000	$ 7,000	$ -	$ 13,000	$ 55,000
G11 - Wholesale Energy Meters	$ -	$ -	$ -	$ -	$ -	$ -
G12 - Current & Potential Transformer (CT & PT)	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 12,500
G13 - Smart Meters	$ 3,250	$ 3,250	$ 3,250	$ 3,250	$ 3,250	$ 16,250
G15 - Data Collectors - Smart Metering	$ -	$ -	$ -	$ -	$ -	$ -
General Plant Totals	**$ 108,250**	**$ 248,250**	**$ 101,750**	**$ 126,750**	**$ 328,250**	**$ 913,250**
Grand Total	***$ 820,316***	***$ 676,363***	***$ 660,331***	***$ 666,971***	***$ 698,224***	***$ 3,522,205***

With respect to the Kinectrics Report asset groupings, the following asset classes are ranked in order of importance with respect to the amount of capital investment allocated towards each of them:

Table 1.14 FFPC 2014 - 2018 Capital Expenditure Summary By Asset Class

FFPC 2014 - 2018 Capital Expenditure Summary By Asset Class		
Kinectrics Asset Class	**2014 - 2018 Total**	
	Total Planned Expenditures	% of Total Planned Expenditures
1 - Fully Dressed Wood Poles	$ 974,319	27.7%
9 - OH Transformers	$ 530,197	15.1%
34 - Pad-Mounted Transformers	$ 515,923	14.6%
G2 - Vehicles	$ 403,000	11.4%
29 - Primary TR XLPE Cables in Duct	$ 182,835	5.2%
17 - Station Independent Breakers	$ 150,000	4.3%
G6 - Computer Equipment	$ 142,500	4.0%
G5 - Station Buildings	$ 93,000	2.6%
43 - Remote SCADA	$ 77,000	2.2%
21 - Digital & Numeric Relays	$ 70,000	2.0%
G3 - Administrative Buildings	$ 65,000	1.8%
8 - OH Conductors	$ 59,180	1.7%
G8 - Communication	$ 55,000	1.6%
G7 - Equipment	$ 34,000	1.0%
4 - OH Line Switch	$ 32,500	0.9%
15 - Station DC System	$ 32,000	0.9%
40 - Ducts	$ 27,000	0.8%
23 - Steel Structure	$ 25,000	0.7%
G13 - Smart Meters	$ 16,250	0.5%
G1 - Office Equipment	$ 15,000	0.4%
G12 - Current & Potential Transformer (CT & PT)	$ 12,500	0.4%
31 - Secondary Cables Direct Buried	$ 10,000	0.3%
Grand Total	***$ 3,522,205***	100.0%

Almost 60% of all investments planned, are allocated towards the replacement or refurbishment of Fully Dressed Wood Poles, Overhead and Pad-Mounted Transformers. With respect to the Kinectrics Report asset groupings, FFPC's total planned expenditures are: 45.3%

or $1,596,197 towards Overhead Plant; 25.9% or $913,250 towards General Plant; $20.9% or $735,758 towards Underground Plant; and 7.9% or $277,000 towards Transformer Stations.

Rate Base Requested for the Test Year

FFPC's rate base is calculated on the average of net fixed assets on 2013 and 2014 plus a 13% working capital allowance of forecasted operating, maintenance, administration and cost of power expenses. FFPC is permitted to earn a rate of return in accordance with rules set by the OEB; however, FFPC has adopted a 0% return on equity so not to violate the terms and conditions a 1905 Historic Power Agreement, as presently defined by a Supreme Court of Canada ruling in 1983.

FFPC is allowed; however, to receive a return on debt, and as such relies on the Board established cost of debt parameters, which have resulted in FFPC adopting a 2.84% Regulated Rate of Return for the 2014 Test Year.

The following table compares the 2006 Board approved and projected 2014 Test Year rate bases.

Table 1.15: Rate Base Calculation & Comparison 2006 OEB Approved vs 2014 Test Year

Rate Base Calculation & Comparison 2006 OEB Approved vs 2014 Test Year		
Calculation Parameters	2006 OEB Approved	2014 Test Year
	CGAAP	CGAAP (new amortization schedule)
Fixed Assets Opening Balance	$ 3,567,772	$ 3,398,023
Fixed Assets Closing Balance	$ 3,427,920	$ 3,939,741
Average Fixed Asset Balance	$ 3,497,846	$ 3,668,882
Working Capital Allowance	$ 962,748	$ 1,124,571
Rate Base	$ 4,460,594	$ 4,793,453

FFPC's last Board approved rate base was from the 2006 EDR, at which time the Board approved a rate base at $4,460,594. FFPC's 2014 Test Year rate base is projected to be 4,793,453, which is a total increase of $332,859. FFPC's rate base increase is mainly

attributable to introducing smart meters into the rate base in 2012, prior to which FFPC's rate base was reduced by $362,837 (as at year end of 2011). FFPC's rate base reductions are largely due to FFPC operating in a "maintenance" mode for the last three decades, as its entire distribution system was rebuilt from the mid-1970s to the mid-1980s, therefore not demanding significant capital reinvestment. Over the 2014 to 2018 planning horizon; however, FFPC must transition to once again operated in a capital rebuild mode, as a disproportionately large number of assets are approaching the end of their useful service lives.

Capital Expenditures requested for the Test Year

FFPC is requesting $820,316 in capital expenditures for the 2014 Test Year, as per the outcomes of FFPC's asset management and capital planning processes. Of the $820,316 in planned capital expenditures, $391,076 have been allocated towards sustaining the lifecycle of existing assets owned, which are estimated to be deteriorating at a rate of $618,169 per year based on FFPC's asset management process. Lifecycle sustaining investments have been kept to a minimum in 2014, in light of the large investments required to satisfy regulatory obligations. FFPC has allocated a total of $421,739 towards mandated service obligations, of which $371,739 are towards the elimination of Long Term Load Transfer arrangements, and $50,000 are towards Renewable Enabling Improvements at FFPC's greater than 50 kV transformer station. Lastly $7,500 of capital investments have been allocated towards accomplishing business objectives. The following activities summarize FFPC's planned 2014 capital budget.

Table 1.16: 2013 Test Year Capital Project Activity Summary

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	USoA Account
2014	General Plant	14-14-007	Misc Building Improvements	$2,000	1808
2014	General Plant	14-14-007	Building Heater Replacements	$3,000	1808
2014	General Plant	14-14-007	Cable Reel Stands	$2,000	1908
2014	General Plant	14-14-007	Replace Shelving	$2,000	1908
2014	General Plant	14-14-007	Meter Room Flooring	$2,500	1908
2014	General Plant	14-14-007	Office A/C	$1,000	1908
2014	General Plant	14-14-007	Admin Area Renovation	$3,500	1908
2014	General Plant	14-14-007	Misc. Main Office furniture replacements	$2,000	1915
2014	General Plant	14-14-007	Misc. Operations Centre furniture replacements	$1,000	1915
2014	General Plant	14-14-007	Operations Centre Copier	$4,000	1920
2014	General Plant	14-14-007	Computer Hardware	$5,000	1920
2014	General Plant	14-14-007	AMI MAS Server Replacement	$4,000	1920
2014	General Plant	14-14-007	AutoCad License	$2,000	1611
2014	General Plant	14-14-007	MS Office Productivity Package	$2,000	1611
2014	General Plant	14-14-007	Small Tools	$5,000	1940
2014	General Plant	14-14-007	Label Printer - Asset Labeling	$2,500	1940
2014	General Plant	14-14-007	Transformer Safe Transport Kit	$3,000	1940
2014	General Plant	14-18-005	Replace 1978 Fort Garry Industries Cable Reel Trailer	$50,000	1930
2014	System Access	14-14-006	LTLT Elimination Pole Lines (88 Pri Spans)	$294,681	1830
2014	System Access	14-14-006	LTLT Elimination Conductor	$9,180	1835
2014	System Access	14-14-006	LTLT Elimination Directional Bore & Conduit	$27,000	1840
2014	System Access	14-14-006	LTLT Elimination Pri UG Conductor	$2,298	1845
2014	System Access	14-14-006	LTLT Elimination Transformers	$38,580	1850
2014	System Access	14-18-004	Transformer T1 Protection	$25,000	1531
2014	System Access	14-18-004	Transformer T2 Protection	$25,000	1531
2014	System Renewal	14-14-007	DC System Battery Cell Replacement	$2,000	1825
2014	System Renewal	14-14-007	UG Service Replacement	$2,000	1855
2014	System Renewal	14-14-007	OH Service Replacement	$2,000	1855
2014	System Renewal	14-14-007	CT/PT and Cabinet Replacements	$2,500	1860
2014	System Renewal	14-14-007	Meter Replacements	$3,250	1860
2014	System Renewal	14-18-001	Primary Poles Replacements	$100,460	1830
2014	System Renewal	14-18-001	Secondary Pole Replacements	$24,110	1830
2014	System Renewal	14-18-001	Unplanned Poles Replacements	$5,358	1830
2014	System Renewal	14-18-002	1 Phase Pad Mounted Tx	$11,036	1850
2014	System Renewal	14-18-002	3 Phase Pad Mounted Tx	$25,106	1850
2014	System Renewal	14-18-002	Pole Mounted Tx	$47,546	1850

2014	System Renewal	14-18-002	Pole Mounted Tx Spares	$11,960	1850
2014	System Renewal	14-18-003	Non-Profit Housing - 400 Blk Sixth St W - S118A To AT15	$4,642	1845
2014	System Renewal	14-18-003	Sixth St Non-Profit Housing	$1,598	1845
2014	System Renewal	14-18-003	Rainy Crest	$10,010	1845
2014	System Service	14-14-007	Primary Insulator Replacements	$10,000	1835
2014	System Service	14-14-007	Air Break Switches Insulator Replacements	$4,500	1835
2014	System Service	14-14-007	Robert Moore Air Break Switch Relocation	$28,000	1835
2014	System Service	14-14-007	Mobile Work Tablets	$2,500	1920
2014	System Service	14-14-007	Elster Tx Primary Data Logger and Meter	$3,500	1945
2014 Total Capital Budget				**$820,316**	

Change in Capital Expenditures from Last Board Approved

Under FFPC's 2006 EDR, the Board approved capital expenditure amount was $139,765, which was established using 2004 data. FFPC is requesting $820,316 in capital expenditures for the 2014 Test Year, which is a change of $680,551. This change reflects FFPC's shift from operating in a "maintenance" mode to a capital "rebuild" mode, based on the outcomes of FFPC's asset management and capital planning processes.

Summary of Planned REG Investments

FFPC has developed a renewable generation enabling improvement plan aimed at safely and reliably accommodating the connection of renewable energy generation facilities. All of FFPC's planned expenditures are for improvements to its transformer station "FFMTS", as the station and its core components are of original 1970's vintage. The station presently cannot accommodate 2-way or reverse electrical flow at any level, as it was designed for the purpose of solely supplying loads.

FFPC's plan is to modify station protection (relaying) and controls over a seven year period, beginning with feeder breakers where it is most likely that a reverse power flow state will be encountered in the near future. FFPC will also be able to improve monitoring of its feeders to establish more accurate and less conservative operating constraints with confidence. Given the current level of interest in renewable generation, FFPC's rationale is to replace relaying and to enhance monitoring in the following sequence over a seven year horizon (years 2012 and 2013 phases have been completed):

1. Tx Station Feeder Breakers
2. Tx Station Transformers and associated Main Secondary Breakers
3. Tx Station Communication Network
4. Tx Station Primary Protection (115 kV Oil Filled Circuit Breakers)
5. Tx Station Supervisory Control & Remote Annunciation

The following table summarizes the planned project phases by year:

Table 1.17: REG Investment Summary

FFPC Planned Renewable Generation Enabling Improvement Project Summary For Years 2012 to 2018			
Planned Year	**Project Name**	**Estimated Cost**	**OEB Investment Category**
2012	T1 Breakers Protection	$ 27,673	System Access
2013	T2 Breakers Protection	$ 35,000	System Access
2014	Transformer T1 Protection	$ 25,000	System Access
2014	Transformer T2 Protection	$ 25,000	System Access
2015	Tx Station Communication Network Installation	$ 20,000	System Access
2015	Tx Station Data Acquisition System	$ 20,000	System Access
2016	Tx Station OCB Protection	$ 20,000	System Access
2017	Tx Station Supervisory Control	$ 45,000	System Access
2018	Tx Station DC System Monitoring & Remote Annunciation	$ 12,000	System Access
	Total	**$ 229,673**	

Summary of Planned Smart Grid

FFPC currently does not have any planned investments specific to only achieving Smart Grid objectives; however, other planned investments such as the previously discussed Renewable Generation Enabling Improvements achieve many of Smart Grid objectives as per the Minister's Directive and subsequent OEB Supplemental Report on Smart Grid.

Summary of Planned Regional Planning Investments

On October 21, 2013 FFPC received a Regional Planning Status Letter from HONI by way of email. The letter also informed FFPC that HONI and OPA are in the early stages of discussions with respect to coordinated regional planning. HONI proceeded to confirm that the formal regional planning process has not yet been initiated, nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the Northwest region affecting FFPC. Formal regional planning efforts are expected to commence in the first quarter of 2014. As such, FFPC is not aware of any deliverables at this time, and has not allocated any funding towards them at this time.

Overview of Operation, Maintenance and Administrative Costs

OM&A expenses for the 2013 Bridge Year and the 2014 Test Year have been based on an in-depth review of FFPC's Distribution System Plan, operating priorities and requirements and is strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

The proposed OM&A expenditures are estimated to be $1,657,650. The increase is predominately due to labour and benefit costs attributed to a number of factors including, increased "overhead" required to implement and maintain regulatory compliance and administer a broad range of initiatives such as smart meters, time of use billing, cost capitalization changes, succession planning, along with changes to the Distribution System Code and Retail Settlement Code. These regulatory initiatives and employee demographics are placing additional challenges on utilities in relation to maintaining effective and cost efficient operations.

Operating costs represent the annual expenditures required to sustain FFPC's distribution operations. FFPC follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of FFPC's operating costs for the 2006 Board Approved, 2006-2012 Actual, 2013 Bridge Year and 2014 Test Year in accordance with the Filing Requirements, is provided in Table 4.2.2 Below:

Table 1.18: Summary of OM&A Expenses

	Last Rebasing Year (2006 Board-Approved)	Last Rebasing Year (2006 Actuals)	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$ 164,815	$ 154,931	$ 167,586	$ 161,730	$ 194,356	$ 192,399	$ 195,697	$ 213,851	$ 209,500	$ 371,000
Maintenance	$ 106,651	$ 92,874	$ 113,833	$ 142,860	$ 130,396	$ 183,394	$ 169,076	$ 377,219	$ 213,000	$ 304,000
Billing and Collecting	$ 144,547	$ 237,343	$ 235,870	$ 254,460	$ 266,345	$ 265,204	$ 213,984	$ 255,946	$ 235,500	$ 268,000
Community Relations	$ 4,712	$ 62,599	$ 35,457	$ 21,187	$ 14,905	$ 8,805	$ 6,024	$ 5,978	$ 4,750	$ 37,150
Administrative and General	$ 600,015	$ 577,417	$ 612,906	$ 686,964	$ 710,557	$ 675,883	$ 717,211	$ 751,977	$ 763,500	$ 677,500
Total	**$ 1,020,740**	**$ 1,125,164**	**$ 1,165,652**	**$ 1,267,201**	**$ 1,316,559**	**$ 1,325,685**	**$ 1,301,992**	**$ 1,604,971**	**$ 1,426,250**	**$ 1,657,650**
%Change (year over year)			3.6%	8.7%	3.9%	0.7%	-1.8%	23.3%	-11.1%	16.2%

OM&A costs in the table above do not include property taxes; however, do represent FFPC's integrated set of asset maintenance and customer service activities to meet public and employee safety objectives; to comply with the Distribution System Code, the Standard Supply Service Code and Retail Settlement Code; environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. FFPC's expenses in 2014 will rise $636,910 over the 2006 Board Approved Actual. This represents an average 5.4% increase per year. As will be discussed in Exhibit 4, the bulk of this increase is due to costs related to the rise in OM&A costs over the eight year period, smart meter initiatives, an error in collection cost planning in the 2006 EDR, succession planning and regulatory compliance requirements.

One of the issues facing FFPC is the hiring of skilled, industry knowledgeable employees. This issue exists at both the administrative and operations departments. FFPC has hired the majority of its staff within the community and provided training and support to develop FFPC's work force. FFPC competes to retain employees by offering comparable wages and benefits and job flexibility. Over the past few years, FFPC started to address wage inequity relative to industry. FFPC reviewed and realigned non-executive salaries with industry norms, relative to regional considerations.

FFPC has taken a proactive approach to succession planning which has resulted in the identification of employees who will be seeking retirement over the next few years, over the 2014 to 2018 planning horizon. Employees who have the potential to replace managerial employees were also identified. Any promotion of these employees will create additional staff movement and a domino effect throughout the organization. In response to the changing business environment and to ensure that FFPC has a sustainable, skilled and knowledgeable staff, FFPC has focused its planning to sustain current positions, transfer expertise to new employees and to ensure business needs are met under a highly regulated business environment.

Within the term of this rate application, two long-term non-union employees, the Lines Superintendent and the Finance and Regulatory Officer, are expected to retire. Should the Superintendent be filled from FFPC's unionized employee complement, this will create a vacancy within the line staff. The replacement of the Finance and Regulatory Officer and Lines Superintendent will require an overlap period such that the new employee is able to benefit from the expertise of the retiree, prior to the retirement taking effect. This strategy will maximize transfer of knowledge, which is crucial is small organizations, to ensure business continue operation in an effective and efficient manner. FFPC proposes to continue with the overlap process as it looks to replace future employees transitioning to retirement.

FFPC is proposing to incorporate a new position of Technical Customer Service Representative to reallocate the following duties that were temporarily assumed by management and union staff;

- Relocate customer service duties such as metering disputes, collection and meter reading duties from current contracted and line staff. This reallocation will allow line staff to focus on existing maintenance and upcoming intensified capital projects;
- Create a dedicated customer contact person for initiatives such as renewable generation, regional planning, energy management, safety and consumer education;
- Assist in the advancement and development of FFPC's software integration initiatives such as the Customer Information System (CIS) interface to the GIS system;
- Assist in maintaining all technical information sources and databases which are relied upon as inputs for regulatory reporting, software system (GIS, AutoCad etc), asset management and capital planning processes;
- Assist in the annual execution of the asset management and capital planning processes;
- Assist in Regional Planning Efforts and attendance of stakeholder consultations;
- Restore FFPC's participation in local events such as trade shows, community safety and educational campaigns.

The volume of information that FFPC is processing from which to make informed business decisions has grown exponentially over the last ten years. Modern day tools such as the AMI and GIS systems offer tremendous insight into the heart of FFPC business, to enable data driven decision making. FFPC requires additional resources to assist with the processing of information and develop its core business system to unlock their full potential.

FFPC's revenue proposal supports maintaining a knowledgeable, adequately sized staffing complement, along with access to the necessary tools required to continue to serve our customers safely, reliably, cost-effectively.

Statement of Capital Cost Parameters

FFPC currently has no debt and operates under a rate minimization strategy. FFPC has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 4.88%, 4% Short Term Debt with a return of 2.11%, and 40% Equity with a return of 0%, as per the revised rates that may be adopted by the OEB in November 2013.

FFPC elects to use a zero Rate of Return on Equity to maintain its Not-for-Profit status, so not to violate the terms and conditions of the 1905 Historic Power Agreement, which is of great benefit to our customers.

Overview of Cost Allocation

FFPC has not deviated from the Board's cost allocation and rate design methodology.

Cost Allocation

FFPC completed the updated cost allocation study and adheres to FFPC's cost data that supports the proposed 2014 revenue requirement outlined in this Application. The breakout of capital assets, depreciation, accumulated depreciation, customer data and load data was developed from the best data available to FFPC, the BDO Advisory services review of FFPC's plant assets, FFPC's Asset Management Process and its customer and financial information systems and records. FFPC has not deviated from the Board's cost allocation methodologies as detailed in the following documents:

- *Report of the Board, Review of Electricity Distribution Cost Allocation Policy, March 31, 2011.*
- *Review of Cost Allocation Policy for Unmetered , May 17, 2013.*

Rate Design

FFPC is proposing that it is appropriate to maintain the same proportion of fixed and variable revenues as approved by the Board in its 2006 EDR application. There are no new rate classes proposed by FFPC within this application.

Overview of Deferral and Variance Accounts

FFPC is requesting approval for the disposition of Group 1 and Group 2 Deferral and Variance Accounts balances as at December 31, 2012 and the forecasted interest through April 30, 2014. The total amount proposed for disposition is -$200,452, excluding Account 1576. FFPC is proposing to dispose of all balances over a two year period to mitigate the rate impacts.

Table 1.19: Disposition of Deferral and Variance Accounts

Proposed DVA Accounts for Disposition		
Account Description	**Account**	**December 31, 2012 Principal Balance**
Group 1 Accounts		**A**
RSVA - Wholesale Market Service Charge	1580	-$99,297
RSVA - Retail Transmission Network Charge	1584	$1,588
RSVA - Retail Transmission Connection Charge	1586	-$156
RSVA - Power (excluding Global Adjustment)	1588	$56,077
RSVA - Global Adjustment	1589	-$224,583
Recovery of Regulatory Asset Balances	1590	$0
Sub-Total (Including Account 1589 - Global Adjustment)		**-$266,371**
Group 2 Accounts		
Other Reg Assets - Sub-Acc - OEB Cost Assessments	1508	$8,451
Other-Reg Assets - Sub-Acc - IFRS Transition Costs	1508	$27,183
Renewable Generation Connection Capital Deferral	1531	$1,966
RSVA-One Time	1582	$6,891
Other Deferred Credits	2425	($6,144)
LRAM	1568	$27,572
Sub-Total- Group Two		**$65,919**
Total Balance for Disposition		**($200,452)**
Accounting Changes under CGAAP	1576	($137,675)

Overview of Bill Impacts

FFPC operates under a rate minimization strategy and has, over the last eight years, only received price cap adjustments to the Board Approved revenue requirement from 2006. The table below details customer impacts, including average dollar impact and average total bill percentage for each rate class.

Table 1.20 Bill Impact Summary

Bill Impacts on the Total Typical Customer Bill			
Rate Classification	**Threshold Typical for Customer Class**	**Bill Impact $**	**Bill Impact %**
Residential	800 kWh	$5.29	4.97%
General Service <50 kW	2000 kWh	$10.36	9.60%
General Service >50 kW	100 kW	-$414.21	-8.55%
Unmetered Scattered Load	2000 kWh	$14.39	6.03%
Street Lighting	88 kW	$388.11	7.40%

The decreases in the General Service Greater than 50 kW account are due to the results of the cost allocation and deferral and variance account rate riders. The increase to the General Service Less than 50 kW and the Street Lighting is due to the result of the cost allocation. Additional information is found in Exhibit 8.

Conclusion

FFPC requests approval of its proposed service revenue requirement of $1,989,765 which includes increases in revenue requirement due to increases in current capital and operating costs, the planned hiring of a Technical Customer Service Representative, customer billing changes and improvements, and in responding to increased regulatory requirements.

Customer Engagement

Overview of Customer Engagement

FFPC is dedicated to providing services in a manner that responds to customer preferences. During the summer of 2013, FFPC conducted an extensive customer satisfaction survey, which was instrumental in gauging satisfaction, identifying improvement opportunities and assessing future customer needs. The feedback gathered has helped to shape our capital expenditures and to devote operational resources over the planning period, to align service offerings with the needs of our customer base.

In July of 2013, FFPC conducted a customer satisfaction survey. All customers were given the opportunity to comment on FFPC's performance, to voice concerns and to indicate customer preferences with respect to present and future service offerings. FFPC was pleased with the results of the survey that was based on 345 out of a total possible 3,733 responses. Surveys were limited to one submission per customer account. FFPC's response to the survey represented 9.2% of its entire customer base, enabling a high degree of confidence from a statistical perspective.

The customer survey broken down into logical section to assess the following; Satisfaction; Experiences with Power Outages; Reliability Expectations; Future Needs; Preferred Service Offerings; Concerns; Education Campaigns; and General Comments. The responses were tabulated and FFPC used the results to guide capital and operational initiatives. The full survey is included in Exhibit 2, as Appendix 3 of FFPC DS Plan "2013 Customer Satisfaction Survey". An exert of the survey results and FFPC's course of action regarding 'Areas of Improvement' is shown in the table below:

Table 2.1: Customer Satisfaction Survey-Improvement Course of Action

% Responses	Improvement	FFPC Course of Action
6.4%	Rate Reduction	Wise Spending through improved asset management and planning practices
3.8%	Access To Billing Data	FFPC will be implementing customer access to billing data
2.3%	Transition to Monthly Billing	FFPC will be transitioning to true calendar monthly billing
2.0%	Announcing Outages	FFPC will be investing in a mass customer contact technology
2.0%	Educating Consumers	FFPC will conduct consumer education campaigns
0.9%	Expand Business Scope	FFPC will evaluate the feasibility of this
0.9%	Length of Power Outages	FFPC is committed to minimizing power outages
0.6%	Other	N/A
0.3%	Arrears Payment Options	FFPC is committed to continually improving its customer care
0.3%	Budget Billing	FFPC is committed to continually improving its customer care
0.3%	Customer Care	FFPC is committed to continually improving its customer care
0.3%	Upgrade Infrastructure	FFPC is committed to up keeping its infrastructure

The survey revealed that FFPC's customers:

1. Are overall very satisfied with the reliability of electricity supplied and with the services provided by FFPC.
2. Feel the most important electricity-related issue facing them is the overall cost of electricity.
3. Would like FFPC to have the ability of contacting them directly, regarding important events such as power interruptions.
4. Would like FFPC to transition to true calendar based monthly billing.
5. Would like a choice of receiving paper of electronic bills.
6. Would like access to monthly billing information.
7. Are very interested in learning more about how they can conserve electricity.

In response to the needs and requests identified, FFPC will be transitioning to true monthly billing, offering a choice of electronic or paper billing, as well as granting access to consumption

and billing data in 2014. FFPC also plans to invest in a mass customer contact system, as well as in an outage management system. These investments will enable FFPC to improve its ability to manage outages, as well as improve FFPC's ability to communicate directly with customers regarding important events such as outages. With the help of this technology, customer communication will be conducted in an efficient and effective manner.

A new "Technical Customer Services Representative" position is also planned to be included in FFPC's organizational structure, to focus on continued customer and stakeholder engagement activities. FFPC also plans to utilize the position to conduct customer education campaigns in local schools, at tradeshows, town hall meetings, as well as through standard media outlets.

As a result of FFPC's customer engagement activities, $58,000 has been dedicated towards capital expenditures to address customer needs, which represents 1.6% of all planned capital expenditures over the 2014 to 2018 planning period. In addition to this, FFPC will be devoting significant staff resources towards the implementation of the above mentioned projects.

As a municipally owned distributor, FFPC frequently utilizes Town Hall Meetings to update the general public regarding about current industry events. FFPC plans to utilize Town Hall Meetings to keep the general public informed with respect to this rate application, as well as the numerous consumer focused activities that FFPC will be undertaking over the course of the 2014 to 2018 planning period. FFPC will educate customers of the key components of this application, as well as to solicit feedback.

Historical Financial Information

FFPC's 2011 and 2012 audited financial statements accompany this schedule as part of Appendix A.

Reconciliation Between Financial Statements and Regulatory Accounting

A detailed reconciliation from 2010-2012 between the financial results shown in FFPC's RRR filings, Audited Financial Statements and with the regulatory financial results filed in the application is presented at the next pages, in Table 1.5.1-1.5.6, inclusive. Changes include revisions to various USoA accounts as instructed in the Board communication dated December 20, 2011.

Table 1.5.1

2010 BALANCE SHEET MAPPED TO AUDITED FINANCIAL STATEMENTS

ACCOUNT	FINANCIAL STATEMENT SECTION	DESCRIPTION	USoA ACCOUNT	ADJUSTMENTS	AUDITED FINANCIAL
1005	Current Asset	Cash	$ 667,680		
1010	Current Asset	Cash Advances and Working Funds	$ 300		**$ 667,980**
1060	Current Asset	Term Deposits	$ 1,425,697		**$ 1,425,697**
1100	Current Asset	Customer Accounts Receivable	$ 519,587		
1102	Current Asset	Accounts Receivable - Services	$ 25,328		
1104	Current Asset	Accounts Receivable - Recoverable Work			
1110	Current Asset	Other Accounts Receivable	$ 1,933,858		**$ 2,478,773**
1190	Current Asset	Miscellaneous Current and Accrued Assets	$ 223,753	$ (223,753)	**$ -**
1130	Current Asset	Accumulated Provision for Uncollectible			
1140	Current Asset	Interest and Dividends Receivable			
1120	Current Asset	Accrued Utility Revenues	$ 890,711		**$ 890,711**
1330	Inventory	Plant Materials and Operating Supplies	$ 119,690		**$ 119,690**
1180	Current Asset	Prepayments	$ 44,814		**$ 44,814**
2294	Current Liability	Accrual for Taxes, Payments in Lieu of Taxes,	$ 8,780		**$ 8,780**
1805	Land and Buildings	Land	$ 100,000		
1808	Land and Buildings	Buildings and Fixtures	$ 819,621		
1820	DS	Distribution Station Equipment - Normally	$ 1,076,223		
1825	Other Distribution Assets	Storage Battery Equipment	$ 8,869		
1830	Poles, Wires	Poles, Towers and Fixtures	$ 4,888,151		
1835	Poles, Wires	Overhead Conductors and Devices	$ 401,309		
1840	Poles, Wires	Underground Conduit	$ 2,183		
1845	Poles, Wires	Underground Conductors and Devices	$ 83,427		
1850	Line Transformers	Line Transformers	$ 1,208,459		
1855	Services and Meters	Services	$ 7,197		
1860	Services and Meters	Meters	$ 391,866		
1908	General Plant	Buildings and Fixtures	$ 390,545		
1910	General Plant	Leasehold Improvements	$ 86,122		
1915	Equipment	Office Furniture and Equipment	$ 117,407		
1920	IT Assets	Computer Equipment - Hardware	$ 42,874		
1925	IT Assets	Computer Software	$ 28,220		
1930	Equipment	Transportation Equipment	$ 815,243		
1940	Equipment	Tools, Shop and Garage Equipment	$ 150,271		
2105	Accumulated Amortizatio	Accum. Amortization of Electric Utility Plant -	$ (7,543,755)		**$ 3,074,231**
1508	Other Assets and Deferrec	Other Regulatory Assets	$ (200,687)	$ 200,687	
1521	Other Assets and Deferrec	Special Purpose Charge	$ 13,918	$ 23,726	
1531	Other	Renewable Connection Capital Deferral	$ 4,320		
1555	O	Smart Meter Capital and Recovery Offset	$ 605,358		
1556		Smart Meter OM&A Variance	$ 172,606		**$ 819,928**
1110	Current Asset	Future Income Tax assets	$ 224,413		**$ 224,413**
					$ 9,755,017
2205	Current Liability	Accounts Payable	$ (1,305,540)		
2208	Current Liability	Customer Credit Balances	$ (42,933)		
2220	Current Liability	Miscellaneous Current and Accrued Liabilities	$ (2,394)		
2256	Current Liability	Independent Market Operator Fees	$ (72,214)	$ 72,214	
2292	Current Liability	Payroll Deductions / Expenses Payable	$ (12,872)		
2315	Liability	Accumulated Provision for Rate Refunds	$ (1,918,399)	$ (660)	**$ (3,282,798)**
2335	Liability	Long Term Customer Deposits	$ (65,198)		**$ (65,197)**
2405	Liability	Other Regulatory Liabilities	$ (4,182)	$ 4,182	
2425	Liability	Other Deferred Credits	$ (1,652)		**$ (1,652)**
2264	Current Liability	Pensions and Employee Benefits - Current	$ (70,053)		
2310	Liability	Vested Sick Leave Liability	$ (44,515)		**$ (114,568)**
1565	CDM Expenditures and Re	Conservation and Demand Management	$ (2,490)		
1566		CDM Contra	$ 2,490		
1580	Other Assets and Deferrec	RSVAWMS	$ (247,825)		
1582	Other Assets and Deferrec	RSVAONE-TIME	$ 6,656		
1584	Other Assets and Deferrec	RSVANW	$ (68)		
1586	Other Assets and Deferrec	RSVACN	$ (525,443)		
1588	Other Assets and Deferrec	RSVAPOWER	$ 427,416		
1590	Other Assets and Deferrec	Recovery of Regulatory Asset Balances	$ (37,328)	$ (76,396)	
2296	Current Liability	Future Income Taxes - Current			
2350	Liability	Future Income Tax - Non-Current	$ (224,413)		**$ (677,401)**
3005	Equity	Common Shares Issued	$ (5,459,825)		
3045	Equity	Unappropriated Retained Earnings	$ (347,565)		**$ (5,807,391)**
3046	Equity	Balance Transferred From Income	$ (17,052)		
3047	Equity	Appropriations of Retained Earnings - Current	$ 211,042		**$ 193,990**
*** UNDERLINE TOTALS USoA ACCOUNTS TO FINANCIAL STATEMENT**		**TOTA**	**$ (0)**	**$0**	**$ (9,755,017)**

Table 1.5.2

2010 TRIAL BALANCE MAPPED TO AUDITED FINANCIAL STATEMENTS

ACCOUNT	FINANCIAL STATEMENT SECTION	DESCRIPTION	USoA ACCOUNT	SUBTOTAL	AUDITED FINANCIAL STATEMENT	DIFFERENCE
4006	Sales of Electricity	Residential Energy Sales	$ (2,641,936)			
4025	Sales of Electricity	Street Lighting Energy Sales	$ (69,514)			
4035	Sales of Electricity	General Energy Sales	$ (2,777,802)			
4050	Sales of Electricity	Revenue Adjustment	$ 805,652			
4055	Sales of Electricity	Energy Sales for Resale				
4062	Sales of Electricity	Billed WMS	$ (539,398)			
4066	Sales of Electricity	Billed NW	$ (382,776)			
4068	Sales of Electricity	Billed CN	$ (124,333)			
4080	Distribution Services Revenue	Distribution Services Revenue	$ (1,463,718)			
4082	Other Distribution Revenue	Retail Services Revenues	$ (1,553)			
4084	Other Distribution Revenue	Service Transaction Requests (STR) Revenues	$ (1,475)	$ (7,196,853)	**$ (7,222,033)**	$ 25,180
4210	Other Distribution Revenue	Rent from Electric Property	$ (47,328)			
4225	Late Payment Charges	Late Payment Charges	$ (24,747)			
4235	Specific Service Charges	Miscellaneous Service Revenues	$ (29,751)			
4245	Other Distribution Revenue	Government Assistance Directly Credited to Income				
4310	Other Income & Deductions	Regulatory Credits				
4324		Special Purpose Charge Recovery				
4325	Other Income & Deductions	Revenues from Merchandise, Jobbing, Etc.	$ (92,264)			
4330	Other Income & Deductions	Costs and Expenses of Merchandising, Jobbing, Etc.	$ 45,116			
4355	Other Income & Deductions	Gain on Disposition of Utility and Other Property	$ 1,220		**$ 1,220**	
4375	Other Revenue - Unclassified	Revenues from Non-Utility Operations	$ (134,362)			
4380	Other Revenue - Unclassified	Expenses of Non-Utility Operations	$ 116,887			
4385	Other Revenue - Unclassified	Non-Utility Rental Income				
4390	Other Income & Deductions	Miscellaneous Non-Operating Income	$ (27,328)			
4405	Other Income & Deductions	Interest and Dividend Income	$ (43,599)	$ (237,376)	**$ (369,592)**	$ 132,216
4705	Power Supply Expenses	Power Purchased	$ 6,310,211			
4708	Power Supply Expenses	Charges-WMS	$ 457,549			
4710	Power Supply Expenses	Cost of Power Adjustments	$ (72,783)			
4714	Power Supply Expenses	Charges-NW	$ 444,505			
4716	Power Supply Expenses	Charges-CN	$ 117,033			
4720	Other Power Supply Expenses	Other Expenses	$ (1,534,411)	$ 5,722,105	**$ 5,722,105**	$ (1)
5012	Operation	Station Buildings and Fixtures Expense	$ 47,180			
5016	Operation	Distribution Station Equipment - Operation Labour	$ 3,956			
5017	Operation	Distribution Station Equipment - Operation	$ 6,068			
5020	Operation	Overhead Distribution Lines and Feeders -	$ 13,910			
5025	Operation	Overhead Distribution Lines & Feeders - Operation	$ 3,405			
5035	Operation	Overhead Distribution Transformers- Operation	$ 6,797			
5040	Operation	Underground Distribution Lines and Feeders -	$ 9,905			
5045	Operation	Underground Distribution Lines & Feeders -	$ 2,574			
5050	Operation	Underground Subtransmission Feeders - Operation	$ 797			
5065	Operation	Meter Expense	$ 22,688			
5085	Operation	Miscellaneous Distribution Expense	$ 75,119			
5114	Maintenance	Maintenance of Distribution Station Equipment	$ 35,111			
5120	Maintenance	Maintenance of Poles, Towers and Fixtures	$ 29,671			
5125	Maintenance	Maintenance of Overhead Conductors and Devices	$ 43,466			
5130	Maintenance	Maintenance of Overhead Services	$ 7,606			
5135	Maintenance	Overhead Distribution Lines and Feeders - Right of	$ 56,248			
5150	Maintenance	Maintenance of Underground Conductors and	$ 8,209			
5155	Maintenance	Maintenance of Underground Services	$ 1,858			
5160	Maintenance	Maintenance of Line Transformers	$ 1,225	$ 375,793	**$ 554,731**	$ (178,938)
5310	Billing and Collection	Meter Reading Expense	$ 31,692			
5315	Billing and Collection	Customer Billing	$ 130,232			
5320	Billing and Collection	Collecting	$ 92,285			
5335	Bad Debt Expense	Bad Debt Expense	$ 10,996	$ 265,204	**$ 264,158**	$ 1,046
5410	Community Relations	Community Relations - Sundry	$ 8,805			
5605	Administrative	Executive Salaries and Expenses	$ 36,497			
5610	Administrative	Management Salaries and Expenses	$ 240,721			
5615	Administrative	General Administrative Salaries and Expenses	$ 161,942			
5620	Administrative	Office Supplies and Expenses	$ 17,528			
5625	Administrative	Administrative Expense Transferred Credit				
5630	Administrative	Outside Services Employed	$ 45,845			
5635	Insurance Expense	Property Insurance	$ 14,447			
5645	Administrative	Employee Pensions and Benefits	$ 70,999			
5655	Administrative	Regulatory Expenses	$ 10,601			
5660	Advertising Expenses	General Advertising Expenses	$ 2,577			
5665	Administrative	Miscellaneous General Expenses	$ 52,515			
5675	Administrative	Maintenance of General Plant	$ 13,284			
5680	Administrative	Electrical Safety Authority Fees	$ 4,539			
5685	Power Supply Expenses	Independent Market Operator Fees and Penalties	$ 4,389	$ 684,689	**$ 677,044**	$ 7,645
5705	Amortization of Assets	Amortization Expense - Property, Plant, and	$ 357,117		**$ 357,117**	
6035	Interest Expense - Unclassifed	Other Interest Expense	$ 6,979		**$ 6,978**	
6105	Other Distribution Expenses	Taxes Other Than Income Taxes	$ 12,775		**$ -**	$ 12,775
6110	Income Tax Expense	Income Taxes	$ (8,780)		**$ (8,780)**	
6205	Charitable Contributions	Donations	$ 76			$ 76
6215	Other Distribution Expenses	Penalties			**$ -**	$ -
		Net Income (Loss)	**$ (17,053)**		**$ (17,052)**	**$ (2)**
			Per USoA		**Per AFS**	

Table 1.5.3

2011 BALANCE SHEET MAPPED TO AUDITED FINANCIAL STATEMENTS

ACCOUNT	FINANCIAL STATEMENT SECTION	DESCRIPTION	USoA ACCOUNT	AUDITED FINANCIAL STATEMENT
1005	Current Asset	Cash	$ 211,948	
1010	Current Asset	Cash Advances and Working Funds	$ 300	$ 212,248
1060	Current Asset	Term Deposits	$ 2,966,569	$ 2,966,569
1100	Current Asset	Customer Accounts Receivable	$ 656,817	
1102	Current Asset	Accounts Receivable - Services	$ 83,033	
1104	Current Asset	Accounts Receivable - Recoverable Work	$ 123,276	
1110	Current Asset	Other Accounts Receivable	$ 57,835	
1190	Current Asset	Miscellaneous Current and Accrued Assets	$ 4,368	
1130	Current Asset	Accumulated Provision for Uncollectible	$ (4,614)	
1140	Current Asset	Interest and Dividends Receivable	$ 11,029	$ 931,744
1120	Current Asset	Accrued Utility Revenues	$ 933,203	$ 933,203
1330	Inventory	Plant Materials and Operating Supplies	$ 117,174	$ 117,174
1180	Current Asset	Prepayments	$ 35,956	$ 35,956
2294	Current Liability	Accrual for Taxes, Payments in Lieu of Taxes,	$ 18,585	$ 18,585
1805	Land and Buildings	Land	$ 100,000	
1808	Land and Buildings	Buildings and Fixtures	$ 823,377	
1820	DS	Distribution Station Equipment - Normally	$ 1,076,223	
1825	Other Distribution Assets	Storage Battery Equipment	$ 9,565	
1830	Poles, Wires	Poles, Towers and Fixtures	$ 5,012,450	
1835	Poles, Wires	Overhead Conductors and Devices	$ 401,309	
1840	Poles, Wires	Underground Conduit	$ 2,183	
1845	Poles, Wires	Underground Conductors and Devices	$ 89,938	
1850	Line Transformers	Line Transformers	$ 1,195,739	
1855	Services and Meters	Services	$ 7,197	
1860	Services and Meters	Meters	$ 391,866	
1908	General Plant	Buildings and Fixtures	$ 394,273	
1910	General Plant	Leasehold Improvements	$ 86,122	
1915	Equipment	Office Furniture and Equipment	$ 117,407	
1920	IT Assets	Computer Equipment - Hardware	$ 45,142	
1925	IT Assets	Computer Software	$ 29,094	
1930	Equipment	Transportation Equipment	$ 696,397	
1940	Equipment	Tools, Shop and Garage Equipment	$ 150,851	
2105	Accumulated Amortizatio	Accum. Amortization of Electric Utility Plant -	$ (7,758,541)	$ 2,870,592
1508	Other Assets and Deferrec	Other Regulatory Assets	$ 23,537	
1521	Other Assets and Deferrec	Special Purpose Charge	$ 2,270	
1531	Other	Renewable Connection Capital Deferral	$ 4,406	
1555	O	Smart Meter Capital and Recovery Offset	$ 496,530	
1556		Smart Meter OM&A Variance	$ 289,137	$ 815,879
1110	Current Asset	Future Income Tax assets	$ 227,762	$ 227,762
				$ 9,129,711
2205	Current Liability	Accounts Payable	$ (932,852)	
2208	Current Liability	Customer Credit Balances	$ (77,716)	
2220	Current Liability	Miscellaneous Current and Accrued Liabilities	$ (1,794)	
2292	Current Liability	Payroll Deductions / Expenses Payable	$ (10,284)	
2315	Liability	Accumulated Provision for Rate Refunds	$ (1,262,902)	$ (2,285,547)
2335	Liability	Long Term Customer Deposits	$ (55,887)	$ (55,887)
2425	Liability	Other Deferred Credits	$ (63,729)	$ (63,729)
2264	Current Liability	Pensions and Employee Benefits - Current	$ (84,936)	
2310	Liability	Vested Sick Leave Liability	$ (47,684)	$ (132,620)
1565	CDM Expenditures and Re	Conservation and Demand Management	$ (2,490)	
1566		CDM Contra	$ 2,490	
1580	Other Assets and Deferrec	RSVAWMS	$ (328,598)	
1582	Other Assets and Deferrec	RSVAONE-TIME	$ 6,696	
1584	Other Assets and Deferrec	RSVANW	$ 17,688	
1586	Other Assets and Deferrec	RSVACN	$ (534,599)	
1588	Other Assets and Deferrec	RSVAPOWER	$ 120,468	
1590	Other Assets and Deferrec	Recovery of Regulatory Asset Balances	$ (37,857)	
2296	Current Liability	Future Income Taxes - Current	$ (3,349)	
2350	Liability	Future Income Tax - Non-Current	$ (224,413)	$ (983,964)
3005	Equity	Common Shares Issued	$ (5,459,825)	
3045	Equity	Unappropriated Retained Earnings	$ (347,565)	$ (5,807,390)
3046	Equity	Balance Transferred From Income	$ 5,436	
3047	Equity	Appropriations of Retained Earnings - Current	$ 193,990	$ 199,425
*** UNDERLINE TOTALS USoA ACCOUNTS TO FINANCIAL STATEMENT**		**TOTAL**	**$ 0**	**$ 9,129,711**

Table 1.5.4

2011 TRIAL BALANCE MAPPED TO AUDITED FINANCIAL STATEMENTS

ACCOUNT	FINANCIAL STATEMENT SECTION	DESCRIPTION	USoA ACCOUNT	SUBTOTAL	AUDITED FINANCIAL	DIFFERENCE
4006	Sales of Electricity	Residential Energy Sales	$ (2,828,132)			
4025	Sales of Electricity	Street Lighting Energy Sales	$ (80,439)			
4035	Sales of Electricity	General Energy Sales	$ (2,869,621)			
4050	Sales of Electricity	Revenue Adjustment	$ 718,698			
4055	Sales of Electricity	Energy Sales for Resale	$ (1,275)			
4062	Sales of Electricity	Billed WMS	$ (537,493)			
4066	Sales of Electricity	Billed NW	$ (444,190)			
4068	Sales of Electricity	Billed CN	$ (128,062)			
4080	Distribution Services Revenue	Distribution Services Revenue	$ (1,456,997)			
4082	Other Distribution Revenue	Retail Services Revenues	$ (540)			
4084	Other Distribution Revenue	Service Transaction Requests (STR) Revenues	$ (1,130)	$ (7,629,181)	**$ (7,658,864)**	$ 29,683
4210	Other Distribution Revenue	Rent from Electric Property	$ (46,784)			
4225	Late Payment Charges	Late Payment Charges	$ (23,669)			
4235	Specific Service Charges	Miscellaneous Service Revenues	$ (8,953)			
4245	Other Distribution Revenue	Government Assistance Directly Credited to Income	$ (1,120)			
4310	Other Income & Deductions	Regulatory Credits	$ (0)			
4324		Special Purpose Charge Recovery	$ 1,068			
4325	Other Income & Deductions	Revenues from Merchandise, Jobbing, Etc.	$ (54,814)			
4330	Other Income & Deductions	Costs and Expenses of Merchandising, Jobbing, Etc.	$ 51,346			
4355	Other Income & Deductions	Gain on Disposition of Utility and Other Property	$ (5,127)		$ (5,127)	
4375	Other Revenue - Unclassified	Revenues from Non-Utility Operations	$ (38,484)			
4380	Other Revenue - Unclassified	Expenses of Non-Utility Operations	$ 36,059			
4385	Other Revenue - Unclassified	Non-Utility Rental Income	$ (22,949)			
4390	Other Income & Deductions	Miscellaneous Non-Operating Income	$ (28,397)			
4405	Other Income & Deductions	Interest and Dividend Income	$ (126,837)	$ (263,534)	**$ (351,635)**	$ 88,101
4705	Power Supply Expenses	Power Purchased	$ 5,874,340			
4708	Power Supply Expenses	Charges-WMS	$ 461,349			
4710	Power Supply Expenses	Cost of Power Adjustments	$ 85,927			
4714	Power Supply Expenses	Charges-NW	$ 461,526			
4716	Power Supply Expenses	Charges-CN	$ 124,916			
4720	Other Power Supply Expenses	Other Expenses	$ (820,231)	$ 6,187,827	**$ 6,213,358**	$ (25,531)
5012	Operation	Station Buildings and Fixtures Expense	$ 45,775			
5016	Operation	Distribution Station Equipment - Operation Labour	$ 6,020			
5017	Operation	Distribution Station Equipment - Operation	$ 10,154			
5020	Operation	Overhead Distribution Lines and Feeders -	$ 9,764			
5025	Operation	Overhead Distribution Lines & Feeders - Operation	$ 73			
5035	Operation	Overhead Distribution Transformers- Operation	$ 1,309			
5040	Operation	Underground Distribution Lines and Feeders -	$ 9,472			
5045	Operation	Underground Distribution Lines & Feeders -	$ 2,251			
5050	Operation	Underground Subtransmission Feeders - Operation	$ 81			
5065	Operation	Meter Expense	$ 36,325			
5085	Operation	Miscellaneous Distribution Expense	$ 74,474			
5114	Maintenance	Maintenance of Distribution Station Equipment	$ 28,207			
5120	Maintenance	Maintenance of Poles, Towers and Fixtures	$ 11,835			
5125	Maintenance	Maintenance of Overhead Conductors and Devices	$ 39,248			
5130	Maintenance	Maintenance of Overhead Services	$ 9,156			
5135	Maintenance	Overhead Distribution Lines and Feeders - Right of	$ 75,245			
5150	Maintenance	Maintenance of Underground Conductors and	$ 3,655			
5155	Maintenance	Maintenance of Underground Services	$ 887			
5160	Maintenance	Maintenance of Line Transformers	$ 843	$ 364,773	**$ 460,162**	$ (95,389)
5310	Billing and Collection	Meter Reading Expense	$ 8,774			
5315	Billing and Collection	Customer Billing	$ 122,531			
5320	Billing and Collection	Collecting	$ 76,855			
5335	Bad Debt Expense	Bad Debt Expense	$ 5,826	$ 213,985	**$ 213,984**	$ 1
5410	Community Relations	Community Relations - Sundry	$ 6,024			
5605	Administrative	Executive Salaries and Expenses	$ 40,979			
5610	Administrative	Management Salaries and Expenses	$ 244,499			
5615	Administrative	General Administrative Salaries and Expenses	$ 160,146			
5620	Administrative	Office Supplies and Expenses	$ 19,576			
5625	Administrative	Administrative Expense Transferred Credit	$ (3,635)			
5630	Administrative	Outside Services Employed	$ 55,089			
5635	Insurance Expense	Property Insurance	$ 15,962			
5645	Administrative	Employee Pensions and Benefits	$ 104,797			
5655	Administrative	Regulatory Expenses	$ 25,855			
5660	Advertising Expenses	General Advertising Expenses	$ 5,322			
5665	Administrative	Miscellaneous General Expenses	$ 26,576			
5675	Administrative	Maintenance of General Plant	$ 13,284			
5680	Administrative	Electrical Safety Authority Fees	$ 4,371			
5685	Power Supply Expenses	Independent Market Operator Fees and Penalties	$ 4,389	$ 723,235	**$ 743,694**	$ (20,459)
5705	Amortization of Assets	Amortization Expense - Property, Plant, and	$ 333,632		**$ 333,632**	
6035	Interest Expense - Unclassifed	Other Interest Expense	$ 74,816		**$ 74,816**	
6105	Other Distribution Expenses	Taxes Other Than Income Taxes	$ 12,484		$ -	$ 12,484
6110	Income Tax Expense	Income Taxes	$ (18,585)		**$ (18,585)**	
6205	Charitable Contributions	Donations	$ 2,034		$ -	$ 2,034
6215	Other Distribution Expenses	Penalties	$ 9,077		$ -	$ 9,077
		Net Income (Loss)	**$ 5,436**		**$ 5,435**	**$ 1**

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Table 1.5.5

2012 BALANCE SHEET MAPPED TO AUDITED FINANCIAL STATEMENTS

ACCOUNT	FINANCIAL STATEMENT SECTION	DESCRIPTION	USoA ACCOUNT	ADJUSTMENTS	AUDITED FINANCIAL STATEMENT
1005	Current Asset	Cash	$ 604,825		
1010	Current Asset	Cash Advances and Working Funds	$ 300		**$ 605,125**
1060	Current Asset	Term Deposits	$ 2,350,425		**$ 2,350,425**
1100	Current Asset	Customer Accounts Receivable	$ 595,384		
1102	Current Asset	Accounts Receivable - Services	$ 130,956		
1104	Current Asset	Accounts Receivable - Recoverable Work			
1110	Current Asset	Other Accounts Receivable	$ 365,014	$ (253,852)	**$ 833,796**
1190	Current Asset	Miscellaneous Current and Accrued Assets		$ 228	
1130	Current Asset	Accumulated Provision for Uncollectible	$ (11,725)		
1140	Current Asset	Interest and Dividends Receivable	$ 7,791		
1120	Current Asset	Accrued Utility Revenues	$ 854,024		**$ 854,024**
1330	Inventory	Plant Materials and Operating Supplies	$ 123,828		**$ 123,828**
1180	Current Asset	Prepayments	$ 37,656		**$ 37,656**
2294	Current Liability	Accrual for Taxes, Payments in Lieu of Taxes,	$ 30,189		**$ 30,189**
1805	Land and Buildings	Land	$ 100,000		
1808	Land and Buildings	Buildings and Fixtures	$ 823,377		
1820	DS	Distribution Station Equipment - Normally	$ 1,076,223		
1825	Other Distribution Assets	Storage Battery Equipment	$ 9,565		
1830	Poles, Wires	Poles, Towers and Fixtures	$ 3,308,296		
1835	Poles, Wires	Overhead Conductors and Devices	$ 1,622,790		
1840	Poles, Wires	Underground Conduit	$ 312,678		
1845	Poles, Wires	Underground Conductors and Devices	$ 427,295		
1850	Line Transformers	Line Transformers	$ 1,209,373		
1855	Services and Meters	Services	$ 7,197		
1860	Services and Meters	Meters	$ 841,418		
1908	General Plant	Buildings and Fixtures	$ 405,108		
1910	General Plant	Leasehold Improvements	$ 86,122		
1915	Equipment	Office Furniture and Equipment	$ 117,407		
1920	IT Assets	Computer Equipment - Hardware	$ 47,053		
1925	IT Assets	Computer Software	$ 29,854		
1930	Equipment	Transportation Equipment	$ 696,397		
1940	Equipment	Tools, Shop and Garage Equipment	$ 153,134		
2105	Accumulated Amortizatio	Accum. Amortization of Electric Utility Plant -	$ (8,022,924)		**$ 3,250,364**
1508	Other Assets and Deferrec	Other Regulatory Assets	$ 34,948		
1521	Other Assets and Deferrec	Special Purpose Charge			
1531	Other	Renewable Connection Capital Deferral	$ 32,142		
1555	O	Smart Meter Capital and Recovery Offset	$ 92,216		
1556		Smart Meter OM&A Variance			**$ 159,306**
1110	Current Asset	Future Income Tax assets		$ 253,852	**$ 253,852**
					$ 8,498,564
2205	Current Liability	Accounts Payable	$ (990,213)		
2208	Current Liability	Customer Credit Balances	$ (61,890)		
2220	Current Liability	Miscellaneous Current and Accrued Liabilities	$ (781,525)		
2292	Current Liability	Payroll Deductions / Expenses Payable	$ (16,613)	$ (228)	
2315	Liability	Accumulated Provision for Rate Refunds			**$ (1,850,469)**
2335	Liability	Long Term Customer Deposits	$ (49,291)		**$ (49,291)**
2425	Liability	Other Deferred Credits	$ (106,480)		**$ (106,480)**
2264	Current Liability	Pensions and Employee Benefits - Current	$ (71,607)		
2310	Liability	Vested Sick Leave Liability	$ (49,115)		**$ (120,722)**
1565	CDM Expenditures and Re	Conservation and Demand Management			
1580	Other Assets and Deferrec	RSVAWMS	$ (174,168)		
1582	Other Assets and Deferrec	RSVAONE-TIME	$ 6,759		
1584	Other Assets and Deferrec	RSVANW	$ 19,401		
1586	Other Assets and Deferrec	RSVACN	$ (1,453)		
1588	Other Assets and Deferrec	RSVAPOWER	$ 46,112		
1589	Other Assets and Deferrec	RSVAGLOBAL	$ (532,253)		
1595	Other Assets and Deferrec	Recovery of Regulatory Asset Balances	$ (188,095)		
2294	Current Liability	Accrual for Taxes, Payments in Lieu of Taxes,			
2296	Current Liability	Future Income Taxes - Current			
2350	Liability	Future Income Tax - Non-Current	$ (253,852)		**$ (1,077,549)**
3005	Equity	Common Shares Issued	$ (5,459,825)		
3045	Equity	Unappropriated Retained Earnings	$ (347,566)		**$ (5,807,391)**
3046	Equity	Balance Transferred From Income	$ 313,913		
3047	Equity	Appropriations of Retained Earnings - Current	$ 199,425		**$ 513,338**
* UNDERLINE TOTALS USoA ACCOUNTS TO FINANCIAL STATEMENT		TOTAL	**$ 0**	**$ -**	**$ (8,498,564)**

Table 1.5.6

2012 TRIAL BALANCE MAPPED TO AUDITED FINANCIAL STATEMENTS

ACCOUNT	FINANCIAL STATEMENT SECTION	DESCRIPTION	USoA ACCOUNT	SUBTOTAL	AUDITED FINANCIAL STATEMENT	DIFFERENCE
4006	Sales of Electricity	Residential Energy Sales	$ (3,018,435)			
4025	Sales of Electricity	Street Lighting Energy Sales	$ (76,652)			
4035	Sales of Electricity	General Energy Sales	$ (3,072,296)			
4050	Sales of Electricity	Revenue Adjustment				
4055	Sales of Electricity	Energy Sales for Resale				
4062	Sales of Electricity	Billed WMS	$ (507,206)			
4066	Sales of Electricity	Billed NW	$ (489,956)			
4068	Sales of Electricity	Billed CN	$ (120,517)	$ (7,285,062)	**$ (7,148,968)**	$ (136,094)
4080	Distribution Services Revenue	Distribution Services Revenue	$ (1,721,940)			
4086	Distribution Services Revenue	SSS Revenue	$ (10,906)			
4082	Other Distribution Revenue	Retail Services Revenues	$ (3)			
4084	Other Distribution Revenue	Service Transaction Requests (STR) Revenues	$ (583)	$ (1,733,432)	**$ (1,740,337)**	$ 6,905
4210	Other Distribution Revenue	Rent from Electric Property	$ (47,142)			
4225	Late Payment Charges	Late Payment Charges	$ (27,178)			
4230	Other Operating Revenue	Sales of Water and Water Power	$ (12,419)			
4235	Specific Service Charges	Miscellaneous Service Revenues	$ (9,003)			
4245	Other Distribution Revenue	Government Assistance Directly Credited to Income	$ (1,120)			
4310	Other Income & Deductions	Regulatory Credits	$ (0)			
4325	Other Income & Deductions	Revenues from Merchandise, Jobbing, Etc.	$ (37,235)			
4330	Other Income & Deductions	Costs and Expenses of Merchandising, Jobbing, Etc.	$ 33,835			
4375	Other Revenue - Unclassified	Revenues from Non-Utility Operations	$ (36,971)			
4380	Other Revenue - Unclassified	Expenses of Non-Utility Operations	$ 36,522			
4385	Other Revenue - Unclassified	Non-Utility Rental Income	$ (1,673)			
4390	Other Income & Deductions	Miscellaneous Non-Operating Income				
4405	Other Income & Deductions	Interest and Dividend Income	$ (45,796)	$ (148,180)	**$ (311,550)**	$ 163,370
4705	Power Supply Expenses	Power Purchased	$ 6,167,382			
4708	Power Supply Expenses	Charges-WMS	$ 507,206			
4714	Power Supply Expenses	Charges-NW	$ 489,956			
4716	Power Supply Expenses	Charges-CN	$ 120,518			
4720	Other Power Supply Expenses	Other Expenses		$ 7,285,062	**$ 7,148,968**	$ 136,094
5012	Operation	Station Buildings and Fixtures Expense	$ 49,550			
5016	Operation	Distribution Station Equipment - Operation Labour	$ 15,034			
5017	Operation	Distribution Station Equipment - Operation	$ 11,651			
5020	Operation	Overhead Distribution Lines and Feeders -	$ 9,080			
5025	Operation	Overhead Distribution Lines & Feeders - Operation	$ 188			
5035	Operation	Overhead Distribution Transformers- Operation	$ 816			
5040	Operation	Underground Distribution Lines and Feeders -	$ 13,547			
5045	Operation	Underground Distribution Lines & Feeders -	$ 2,724			
5050	Operation	Underground Subtransmission Feeders - Operation				
5065	Operation	Meter Expense	$ 28,697			
5075	Operation	Customer Premises -Materials and Expenses	$ 595			
5085	Operation	Miscellaneous Distribution Expense	$ 81,970			
5114	Maintenance	Maintenance of Distribution Station Equipment	$ 31,624			
5120	Maintenance	Maintenance of Poles, Towers and Fixtures	$ 25,911			
5125	Maintenance	Maintenance of Overhead Conductors and Devices	$ 39,980			
5130	Maintenance	Maintenance of Overhead Services	$ 5,377			
5135	Maintenance	Overhead Distribution Lines and Feeders - Right of	$ 66,563			
5150	Maintenance	Maintenance of Underground Conductors and	$ 20,016			
5155	Maintenance	Maintenance of Underground Services	$ 116			
5160	Maintenance	Maintenance of Line Transformers	$ 590			
5175	Maintenance	Maintenance of Meters	$ 187,044	$ 591,072	**$ 762,649**	$ (171,577)
5310	Billing and Collection	Meter Reading Expense	$ 5,488			
5315	Billing and Collection	Customer Billing	$ 146,109			
5320	Billing and Collection	Collecting	$ 93,373			
5335	Bad Debt Expense	Bad Debt Expense	$ 10,976	$ 255,946	**$ 255,774**	$ 172
5410	Community Relations	Community Relations - Sundry	$ 5,978			
5605	Administrative	Executive Salaries and Expenses	$ 44,526			
5610	Administrative	Management Salaries and Expenses	$ 244,612			
5615	Administrative	General Administrative Salaries and Expenses	$ 170,978			
5620	Administrative	Office Supplies and Expenses	$ 20,893			
5625	Administrative	Administrative Expense Transferred Credit	$ (3,460)			
5630	Administrative	Outside Services Employed	$ 82,503			
5635	Insurance Expense	Property Insurance	$ 15,855			
5645	Administrative	Employee Pensions and Benefits	$ 80,942			
5655	Administrative	Regulatory Expenses	$ 46,920			
5660	Advertising Expenses	General Advertising Expenses	$ 8,324			
5665	Administrative	Miscellaneous General Expenses	$ 17,004			
5675	Administrative	Maintenance of General Plant	$ 13,284			
5680	Administrative	Electrical Safety Authority Fees	$ 5,205			
5685	Power Supply Expenses	Independent Market Operator Fees and Penalties	$ 4,389	$ 757,953	**$ 771,980**	$ (14,027)
5705	Amortization of Assets	Amortization Expense - Property, Plant, and	$ 564,032		**$ 564,032**	
6035	Interest Expense - Unclassifed	Other Interest Expense	$ 33,818		**$ 33,818**	
6105	Other Distribution Expenses	Taxes Other Than Income Taxes	$ 12,264		$ -	$ 12,264
6110	Income Tax Expense	Income Taxes	$ (22,453)		**$ (22,453)**	
6205	Charitable Contributions	Donations	$ 2,730		$ -	$ 2,730
6215	Other Distribution Expenses	Penalties	$ 164		$ -	$ 164
		Net Income (Loss)	**$ 313,913**		**$ 313,913**	**$ 0**
			Per USoA		**Per AFS**	

2012 Annual Report and Management Discussion for Fort Frances Power Corporation

FFPC's 2012 Financial Statement is provided as Appendix A. FFPC has not included an annual report or Management discussion and analysis, as FFPC only prepares notes to the financial statement.

Rating Agency Reports

FFPC does not obtain rating agency reports.

Prospectuses and Information Circulars for Recent and Planned Public Issuances

FFPC has no current or planned future public issuances.

Materiality Thresholds

Overview

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued by the Board June 28, 2012 states the relevant default materiality threshold as:

> "$50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million".

Since FFPC's distribution revenue requirement is less than $10M, FFPC has chosen the default of $50,000 as the appropriate materiality threshold in this Application. However, you will note FFPC has made every effort to ensure all variances and analysis is prepared, even for variances under $50,000 in order to assist in analyzing FFPC's COS Application.

ADMINISTRATION

Statement of Publication

FFPC's customers, served within the municipal boundaries of the Town of Fort Frances. FFPC will publish the notice of this application in the Fort Frances Times, which is the only local newspaper serving the Town of Fort Frances with a circulation of approximately 4,000 unpaid circulation one day a week and paid subscriptions available daily.

Publication Information:	Fort Frances Times, 116 First Street E, Fort Frances, ON P9A 3M7 Circulation: Main Newspaper- weekday delivery

Interested parties can view the application on FFPC's website at: **http://ffpc.fort-frances.com/**

Contact Information

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Cell 416.825.4144
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Requested Approval Date

The Applicant applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2014. In the event that the OEB is unable to provide a Decision and Order on the Application before June 1, 2014 for implementation of rates by FFPC as of May 1, 2014, FFPC requests the OEB issue an Interim Order approving the current distribution rates and other charges, effective May 1, 2014.

Bill Impact

In preparing this application, FFPC has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, FFPC notes that only the General Service >50 kW rate class fall outside the applicable threshold defined by the Board in the March 31, 2013 Report of the Board on Review of Electricity Distribution Cost Allocation Policy (EB-2011-0219). In this application, the General Service >50 kW rate class have been brought within the Board's threshold with minimal impact to other classes.

Customer impacts, including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised retail transmission rates, revised loss factors, Stranded Meter rate rider, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out in Tables 1.5.7 and 1.5.8 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8, Appendix A.

Table 1.5.7: Bill Impacts – Residential

Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed a

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 12.0500	1	$ 12.05	$ 18.7900	1	$ 18.79	$ 6.74	55.93%
Smart Meter Rate Adder (SMIRR)	Monthly	$ 3.4300	1	$ 3.43		1	$ -	-$ 3.43	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0088	800	$ 7.04	$ 0.0137	800	$ 10.96	$ 3.92	55.68%
Smart Meter Disposition Rider	Monthly	$ 3.5800	1	$ 3.58		1	$ -	-$ 3.58	-100.00%
Stranded Meter Charge	Monthly		800	$ -	$ 0.9800	1	$ 0.98	$ 0.98	
Sub-Total A (excluding pass through)				$ 26.10			$ 30.73	**$ 4.63**	**17.74%**
Rate Rider for DVA (2013)	per kWh	-$ 0.0004	800	-$ 0.32	-$ 0.0004	800	-$ 0.32	$ -	0.00%
Rate Rider Global Adjust (2013)	per kWh								
Rate Rider for DVA (2014)	per kWh			$ -	$ 0.0002	800	$ 0.16		
Rate Rider CGAAP Changes	per kWh			$ -	-$ 0.0004	800	-$ 0.32		
GEA Rate Adder	Monthly				$ 0.0700	1	$ 0.07	$ 0.07	
Line Losses on Cost of Power		$ 0.0839	32.48	$ 2.73	$ 0.0839	37.60	$ 3.16	$ 0.43	15.76%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.30**			**$ 34.27**	**$ 4.97**	**16.96%**
RTSR - Network	per kWh	$ 0.0066	832	$ 5.49	$ 0.0067	838	$ 5.61	$ 0.12	2.14%
RTSR - Line and Transformation Connection	per kWh	$ 0.0015	832	$ 1.25	$ 0.0016	838	$ 1.34	$ 0.09	7.32%
Sub-Total C - Delivery (including Sub-Total B)				**$ 36.04**			**$ 41.22**	**$ 5.18**	**14.37%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	832	$ 3.66	$ 0.0044	838	$ 3.69	$ 0.02	0.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	832	$ 1.00	$ 0.0012	838	$ 1.01	$ 0.01	0.62%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0047	800	$ 3.76	$ 0.0047	800	$ 3.76	$ -	0.00%
TOU - Off Peak		$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak		$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak		$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	800	$ 60.00	$ 0.0750	800	$ 60.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 111.85**			**$ 117.05**	**$ 5.21**	**4.66%**
HST		13%		$ 14.54	13%		$ 15.22	$ 0.68	4.66%
Total Bill (including HST)				$ 126.39			$ 132.27	$ 5.88	4.66%
Ontario Clean Energy Benefit [1]				-$ 12.64			-$ 13.23	-$ 0.59	4.67%
Total Bill on TOU (including OCEB)				**$ 113.75**			**$ 119.04**	**$ 5.29**	**4.65%**
Total Bill on RPP (before Taxes)				**$ 104.71**			**$ 109.92**	**$ 5.21**	**4.97%**
HST		13%		$ 13.61	13%		$ 14.29	$ 0.68	4.97%
Total Bill (including HST)				$ 118.32			$ 124.21	$ 5.88	4.97%
Ontario Clean Energy Benefit [1]				-$ 11.83			-$ 12.42	-$ 0.59	4.99%
Total Bill on RPP (including OCEB)				**$ 106.49**			**$ 111.79**	**$ 5.29**	**4.97%**
Loss Factor (%)		4.06%			4.70%				

Table 1.5.8 Bill Impacts –General Service <50kW

Bill Impacts

Customer Class: General <50 kW

TOU / non-TOU: TOU

Consumption 2,000 kWh May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 29.0300	1	$ 29.03	$ 43.6200	1	$ 43.62	$ 14.59	50.26%
Smart Meter Rate Adder (SMIRR)	Monthly	$ 7.1900	1	$ 7.19		1	$ -	-$ 7.19	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0066	2,000	$ 13.20	$ 0.0099	2,000	$ 19.80	$ 6.60	50.00%
Smart Meter Disposition Rider	Monthly	$ 13.4200	1	$ 13.42		1	$ -	-$ 13.42	-100.00%
Stranded Meter Charge	Monthly		2,000	$ -	$ 8.0900	1	$ 8.09	$ 8.09	
Sub-Total A (excluding pass through)				$ 62.84			$ 71.51	**$ 8.67**	**13.80%**
Rate Rider for DVA (2013)	per kWh	-$ 0.0004	2,000	-$ 0.80	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider Global Adjust (2013)	per kWh								
Rate Rider for DVA (2014)	per kWh				$ 0.0003	2,000	$ 0.60		
Rate Rider CGAAP Changes	per kWh				-$ 0.0004	2,000	-$ 0.80		
GEA Rate Adder	Monthly			$ -	$ 0.0700	1	$ 0.07	$ 0.07	
Line Losses on Cost of Power		$ 0.0839	81.20	$ 6.81	$ 0.0839	94.00	$ 7.89	$ 1.07	15.76%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 69.64**			**$ 79.26**	**$ 9.61**	**13.80%**
RTSR - Network	per kWh	$ 0.0060	2081	$ 12.49	$ 0.0061	2094	$ 12.77	$ 0.29	2.29%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	2081	$ 2.71	$ 0.0014	2094	$ 2.93	$ 0.23	8.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 84.84**			**$ 94.96**	**$ 10.13**	**11.94%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2081	$ 9.16	$ 0.0044	2094	$ 9.21	$ 0.06	0.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2081	$ 2.50	$ 0.0012	2094	$ 2.51	$ 0.02	0.62%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0047	2000	$ 9.40	$ 0.0047	2000	$ 9.40	$ -	0.00%
TOU - Off Peak		$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak		$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak		$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 173.28**			**$ 183.48**	**$ 10.20**	**5.89%**
HST		13%		$ 22.53	13%		$ 23.85	$ 1.33	5.89%
Total Bill (including HST)				$ 195.80			$ 207.33	$ 11.52	5.89%
Ontario Clean Energy Benefit [1]				-$ 19.58			-$ 20.73	-$ 1.15	5.87%
Total Bill on TOU (including OCEB)				**$ 176.22**			**$ 186.60**	**$ 10.37**	**5.89%**
Total Bill on RPP (before Taxes)				**$ 106.14**			**$ 116.34**	**$ 10.20**	**9.61%**
HST		13%		$ 13.80	13%		$ 15.12	$ 1.33	9.61%
Total Bill (including HST)				$ 119.94			$ 131.46	$ 11.52	9.61%
Ontario Clean Energy Benefit [1]				-$ 11.99			-$ 13.15	-$ 1.16	9.67%
Total Bill on RPP (including OCEB)				**$ 107.95**			**$ 118.31**	**$ 10.36**	**9.60%**
Loss Factor (%)		4.06%			4.70%				

Form of Hearing Requested

FFPC is requesting that this Application be dealt with through a written hearing as it is a more cost effective and efficient manner to deal with this proceeding. FFPC is a small northern LDC and travel costs to Toronto are both cost prohibitive and involve a minimum of two days of travel.

List of Approvals

In this proceeding, Fort Frances Power Corporation is requesting the following approvals:

- Approval to charge rates effective May 1, 2014 to recover a revenue requirement of $1,989,765 which includes a revenue deficiency of $459,007 as set out in Exhibit 6, Tab 1, Schedule 1; the schedule of proposed rates is set out in Exhibit 8, Schedule 6;
- Approval of the proposed loss factor of as set out in Exhibit 8, Schedule 6;
- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8, Schedule 1;
- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of FFPC's 2013 Distribution Rates (EB-2012-0083);
- Approval for the proposed Specific Service Charges and Transformer Allowance as set out in Exhibit 8;
- Approval to dispose of the following Deferral and Variance Account balances as at December 31 2012 over a two year period using the method of recovery described in Exhibit 9, Tab 1, Schedule 2:

  1508 Other Regulatory Assets - Sub-account Deferred IFRS Transition Costs

  1508 Other Regulatory Assets – Sub-account OEB Cost Assessment

  1531 Renewable Generation Connection Capital Deferral Account

  1568 LRAM Variance Account

  1576 Accounting Changes Under CGAAP Balance

  1580 RSVA - Wholesale Market Service Charges

1582 RSVA – One Time Charges

1584 RSVA - Transmission Network

1586 RSVA - Transmission Connection

1588 RSVA - Power

1589 RSVA – Global Adjustment

2425 Other Deferred Credits- Shared Tax Savings

- Approval for a stranded meter rate rider of $0.98 per month per metered Residential customer and $8.09 per month per metered General Service <50kW customer, and $22.51 per month per metered General Service >50kW customer for one year to recover the net book value of $92,216 for stranded meters as at December 31, 2013.

- Approval to realign the Revenue to Cost rates as detailed in Exhibit 7.

- Approval of FFPC's Distribution System Plan, Asset Management Policy and Renewable Enabling Improvements as set out in Exhibit 2;

- In the event the OEB is unable to provide a Decision and Order on the Application before June 1, 2014 for implementation of rates by FFPC as of May 1, 2014, FFPC requests the OEB issue an Interim Order approving the current distribution rates and other charges, effective May 1, 2014.

- That FFPC's Greater than 50 kV Transformer Station continue to be deemed a distribution asset.

Changes in Tax Status

Fort Frances Power Corporation is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in Fort Frances, Ontario. Fort Frances Power Corporation has not had a change in tax status since its last Cost of Service Application.

Accounting Orders Requested

Fort Frances Power Corporation is not requesting Accounting Orders in this proceeding.

Compliance with Uniform System of Accounts

FFPC has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

FFPC has filed trial balances, financial statements and forecasted results for the 2013 Bridge year, 2014 Test Year and all proceeding years in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

Description of Operation Environment

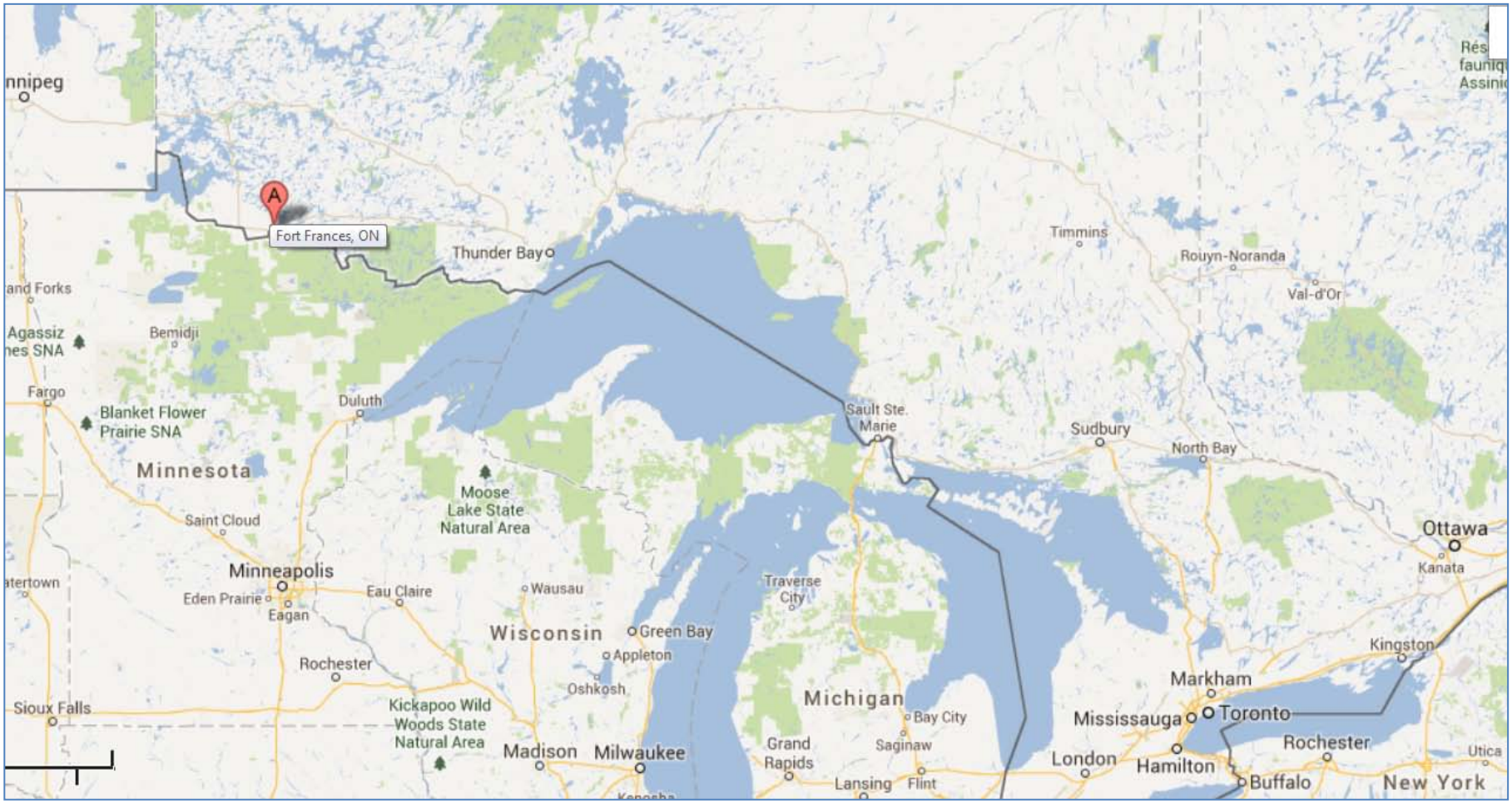
Description of Distributor:

COMMUNITY SERVED:	Town of Fort Frances
TOTAL SERVICE AREA:	26 sq km
RURAL SERVICE AREA:	26 sq km
DISTRIBUTION TYPE:	Electricity distribution
MUNICIPAL POPULATION:	7,952
POPULATION OF URBAN AREAS SERVED:	7,952

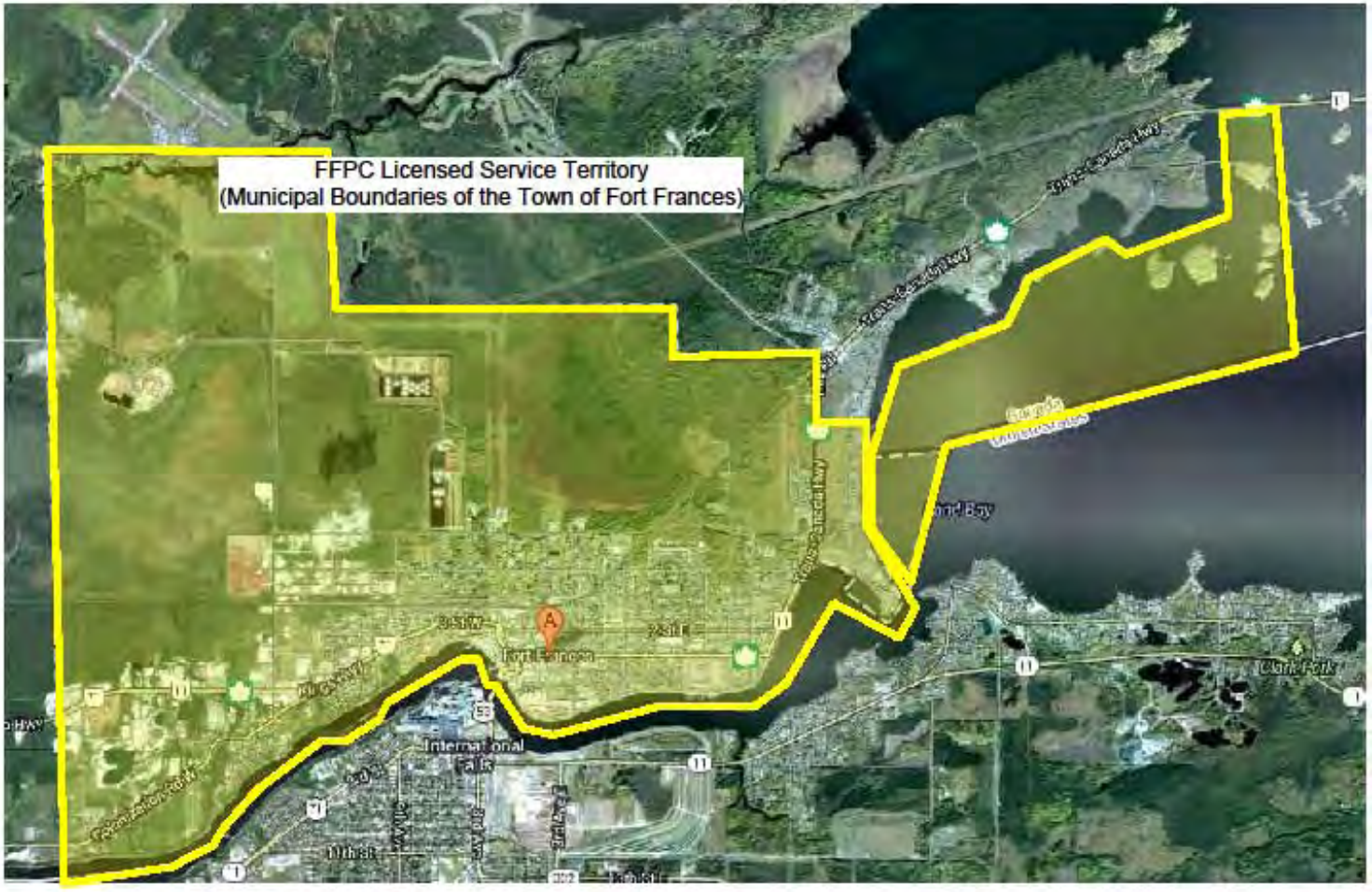
Note: FFPC's customer density fall below the 60 customers per line kilometer, as set out in Appendix C of the DSC. Although FFPC's service area is technically classified as "Rural", FFPC treats its service territory as "Urban" to adhere to adhere to the more stringent regulatory requirements.

The following maps show where FFPC operates with the province of Ontario and the community that it serves.

Location of Fort Frances Power Corporation Within the Province

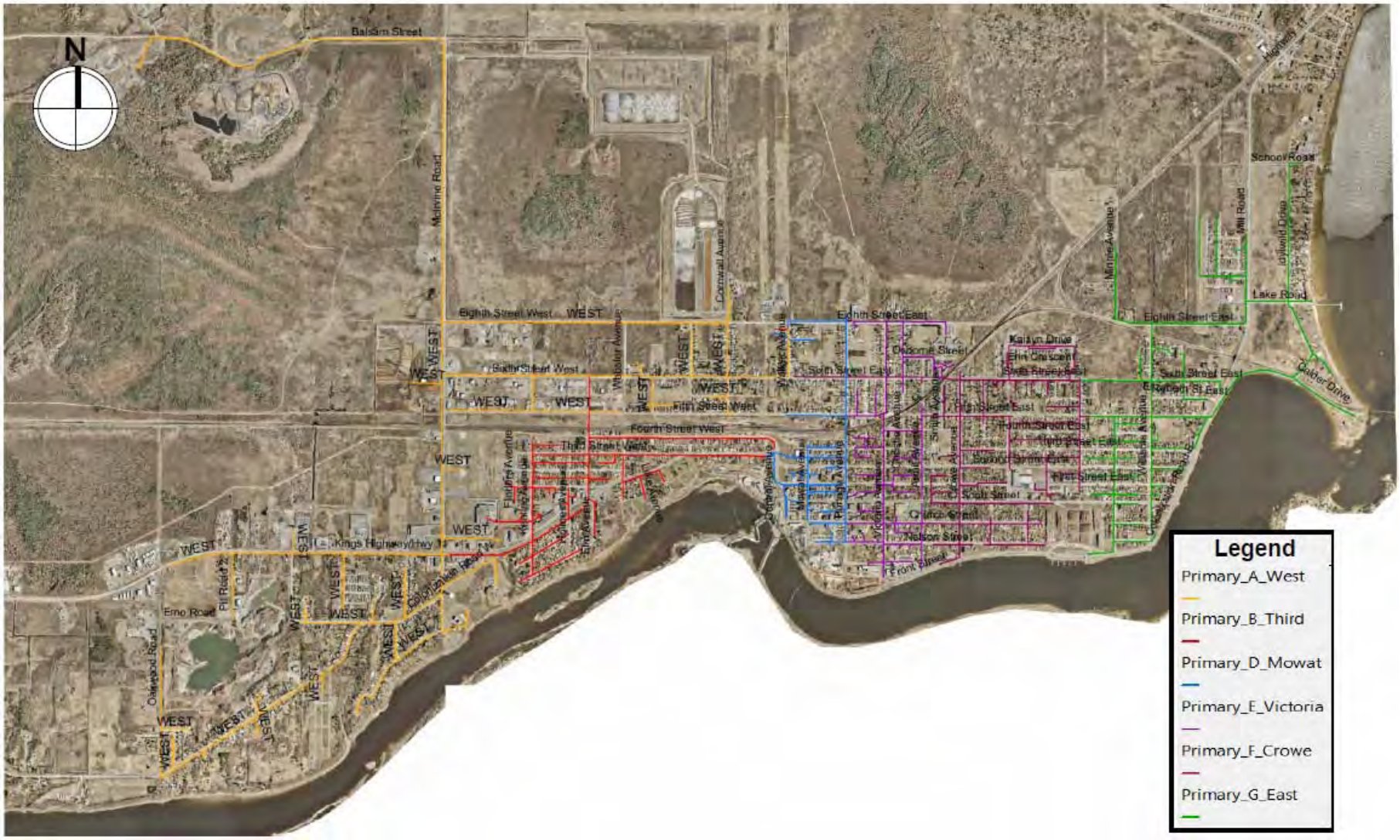


Map of Licensed Distribution Service Territory



Boundary Utilities: **NORTH, WEST:** Township of Alberton- Hydro One. **NORTH, EAST** : Couchiching First Nations- Hydro One
SOUTH : Rainy River and International Border with International Falls, Minnesota- Minnesota Power, an ALLETE Company.

Map of Distribution Feeders



List of Neighbouring Utilities:

Hydro One Networks Inc.
483 Bay Street
South Tower, 10th Floor
Toronto, ON
M5G 2P5

Minnesota Power and Light, An ALLETE Company
30 W Superior St,
Duluth, MN
55802, United States
218-722-2625

Explanation of Host and Embedded Utilities

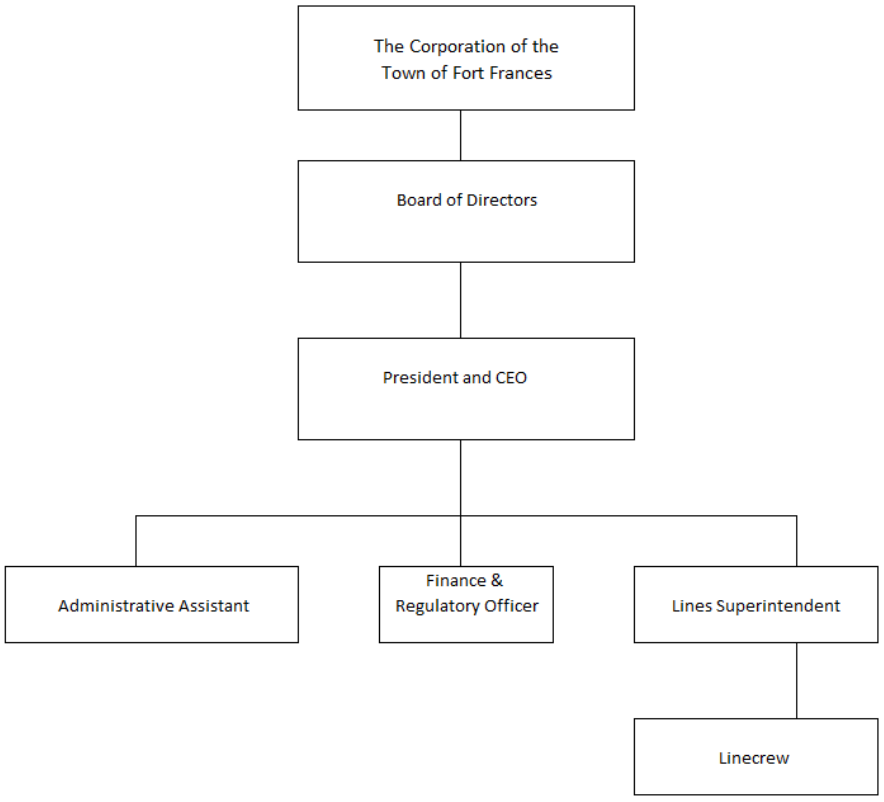
FFPC is a non-dispatchable Local Distribution Company (LDC) and is a registered Market Participant, 104313, dealing directly with the IESO. FFPC has one metering point at the Fort Frances Municipal Transformer Station. Thunder Bay Hydro is FFPC's Meter Service Provider. Consequently, FFPC deals only with IESO for the purchase of electricity which is passed on through to our customers.

FFPC does not host any utilities within its service area.

Corporate and Utility Organizational Structure

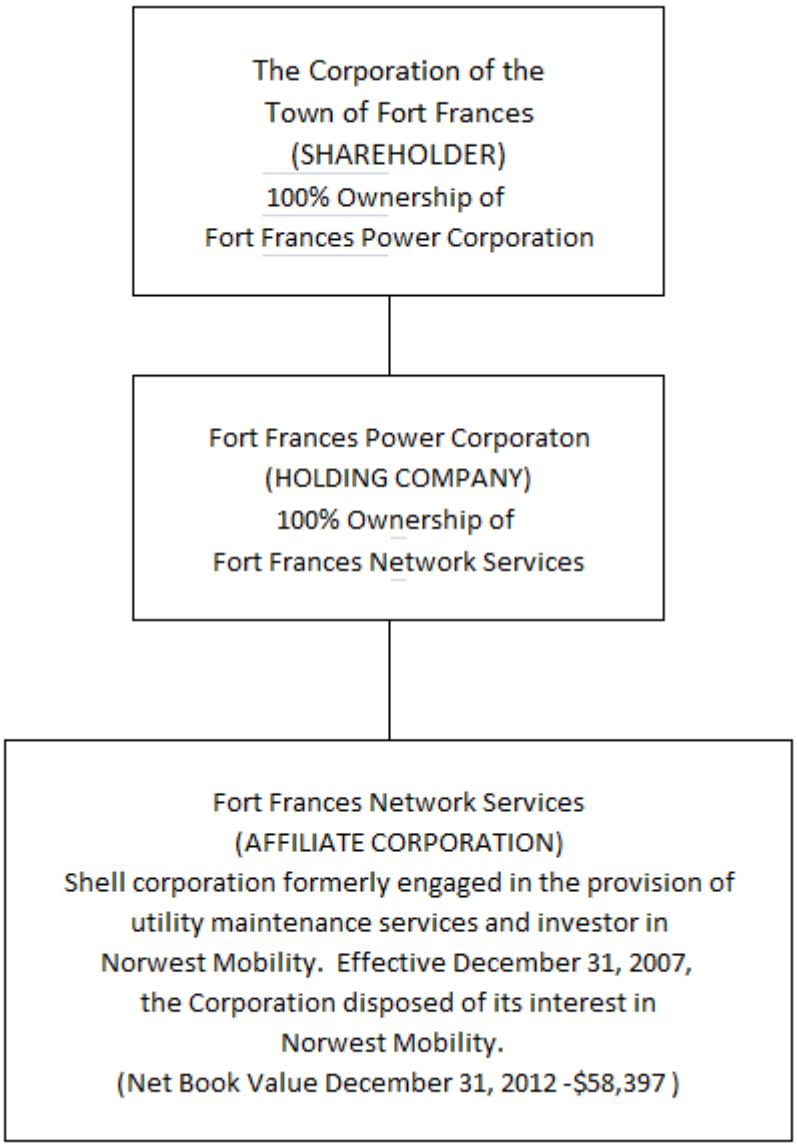
Utility Organizational Structure:

Fort Frances Power Corporation's organization chart is below:

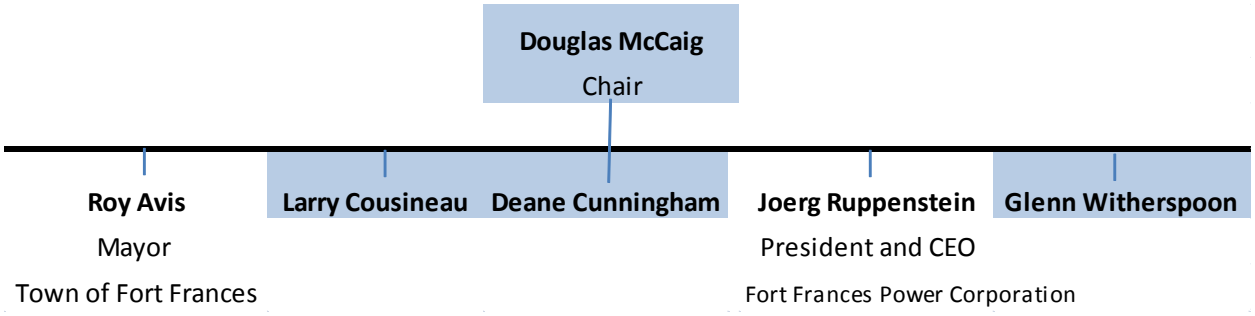


Corporate Entities Relationship Chart:

Fort Frances Power Corporation is 100% owned by the chart illustrating the Corporate Entities Relationships is as follows:



Corporate Entities Relationship Chart



Fort Frances Power Corporation's Board of Directors is represented by one Board member that is related to its parent company, as Mayor of the Town of Fort Frances and one Board member that is the President and CEO of the Fort Frances Power Corporation.

Fort Frances Power Corporation's President and Chief Executive Officer ('CEO') reports to the Board of Directors.

The independent members of the Board are highlighted in blue in the above Corporate Entities Relationship Chart.

Planned Changes in Corporate and Organizational Structure

No changes to Fort Frances Power Corporation's corporate and operational structures are planned at the present time.

Corporate Governance

As noted above, Fort Frances Power Corporation (FFPC) is a wholly owned corporation whose sole shareholder is the Town of Fort Frances. FFPC owns a shell corporation, Fort Frances Network Services Inc., that provided cell phone service under Norwest Mobility, whose assets were sold in 2007.

The Board of Directors of FFPC has governance responsibility for the holding company and all non-regulated subsidiaries. The Board of Directors of FFPC (the "Fort Frances Power Corporation Board") has direct responsibility for the governance of Fort Frances Power Corporation. The Board is active and diligent in their role of oversight and monitoring and believe in the importance of excellence in corporate governance. The Board regularly review and adopt, where appropriate, best practices in corporate governance.

Board of Directors

FFPC has five independent corporate board members (i.e. board members are not the Employees/Officers/Management of FFPC). The FFPC Board conforms to the Affiliate Relationship Code ("ARC") with one-third of its directors independent from Affiliates. FFPC's policy with respect to the proportion of independent directors is to comply with the requirements of both the Affiliate Relationship Code and the Ontario Business Corporations Act (OBCA).

The Fort Frances Power Corporation Board members consist of individuals with a variety of professional backgrounds. Their biographies are provided below.

Doug McCaig - Board Chair:

Doug McCaig was born and raised in the Fort Frances area. Doug worked in the electrical trades gaining his electrical technologist designation. Doug then pursued a career in teaching after he graduated from Lakehead University with a Bachelor of Arts Degree, Majoring in English. Doug established the Seven Generations Education private school and worked in various capacities of the schooling system including Teacher, Guidance Counselor, Technical and Occupational Department Head, Vice Principal and Alternative School Coordinator. Doug became involved in the electrical sector when he became an elected commissioner of the Fort Frances Public Utility Commission. Doug proceeded to become a Board member of Ontario Hydro where he sat on various committees including Nuclear Review, Human Resources, International Investments, Audit and Finance, Aboriginal Relations. Doug also served as Chairman of Fort Frances Network Services, playing a lead role in bringing cell phone coverage to Northern Ontario. Currently Doug has over 39 years experience in the electrical utility business. Doug also played a major role representing the residents and small businesses of Fort Frances in the 1905 Historic Power Agreement dispute that was resolved at the Supreme Court of Canada.

Larry Cousineau - Vice Chair and Secretary

Larry Cousineau, of Fort Frances, was involved in municipal politics for over ten years serving as a town councilor. Larry became an elected commissioner of the Fort Frances Public Utilities Commission (former Fort Frances Power Corporation) in 1992. During his time as commissioner Larry served as a director of Northwest Energy. Larry also served on the executive of the Electrical Distributor's Association Northwest Region and has received the EDA's Long Term

Service Award. Larry dedicated his career to working in a family owned and operated insurance company, Cousineau Brokers. Larry has also volunteered much of his to chairing the Riverside Foundation for Health Care, which was instrumental in bringing a CT Scanner to the Fort Frances La Verendrye Hospital. Larry also played a major role representing the residents and small businesses of Fort Frances in the 1905 Historic Power Agreement dispute that was resolved at the Supreme Court of Canada. Larry has an extensive background in business holding the position of President of the Chamber of Commerce as well as being a Charter Member of the Business Improvement Association of Fort Frances.

Roy Avis - Director:

Roy Avis of Fort Frances comes from a family who has been very involved in Municipal politics. Roy was elected to be the Mayor of the Town of Fort Frances in 2006 and is presently the Mayor (Roy's father Allan Avis was also the Mayor of the Town of Fort Frances from 1972 to 1980). Roy has been a very active community member including being the Trustee for the Fort Frances Rainy River District School Board, a member of the Board of Directors of the Fort Frances Curling Club, member of the Police Services Board and as a director of the Fort Frances Network Services Corporation. Outside of Municipal politics Roy has been the President of West End Motors Inc., a family owned and operated Daimler Chrysler Dealership. Roy has over forty years of business experience and was also a member of the Bill 35 Committee that restructured the Fort Frances Public Utilities Commission to the Fort Frances Power Corporation.

Deane Cunningham - Director:

Deane Cunningham, of Fort Frances, was involved in municipal politics for twenty-six years. Dean was elected to be the Mayor of Fort Frances from 1981 to 1985. In 1981 Deane became a member of the Fort Frances Public Utilities Commission during the rebuild phase of the distribution system in Fort Frances. Deane sat on the Bill 35 Committee during the

restructuring the Fort Frances Public Utilities Commission creating the Fort Frances Power Corporation. Deane also was appointed to be a director on the Fort Frances Network Services Board of Directors, bringing cell phone coverage to Northwestern Ontario. Deane donated much of his time as Vice-Chair of the Riverside Foundation for Health Care and as the Chair of the Just Image Fundraising campaign that brought a CT Scanner to our local hospital. Deane also played a major role representing the residents and small businesses of Fort Frances in the 1905 Historic Power Agreement dispute that was resolved at the Supreme Court of Canada. Deane has also an extensive business background, dedicating over fourty years in the Furniture Retail Business.

Glenn Witherspoon - Director:

Glenn Witherspoon was born and raised in the Fort Frances area. He moved to the USA in 1961 to play hockey and serve in the USA Air National Guard. In 1967 he returned to Fort Frances to work in a family business and to manage and coach the Fort Frances Union A Royals (Hockey). Glenn was involved in municipal politics for eighteen years. From 1991 to 2003 Glenn served as the Mayor of the Town of Fort Frances. He was also a municipal councilor for the town from 1985 to 1991. Outside of municipal politics Glenn was the owner and manager of Witherspoon's One Stop, a local service station and convenience store as well as is currently a partner in the Fort Frances Duty Free. Glenn also served as president of a variety of organization including the Rainy River Municipal Association, Northern Ontario Municipal Association and local Minor Hockey.

Board Mandate

FFPC's Board of Directors do not operate under a formal written mandate at this time. The following best describe the Board of Director's responsibilities and duties:

1. To assess and approve FFPC's Vision, Mission and Values.
2. To ensure that the rights and obligations of the 1905 Historic Power Agreement are upheld on behalf of the residents and small businesses of the Town of Fort Frances.
3. To assess and approve FFPC's strategic plan.
4. To assess and approve FFPC's business objectives.
5. To establish assess and approve FFPC's corporate policies and procedure.
6. FFPC's risk management.
7. To approve budgets, expenditures and legally binding contracts as per FFPC's Purchasing Policy.
8. To ensure that FFPC conducts its business in an ethical manner and in compliance with all governing laws, regulations and statutes.
9. To select, appoint, support and review the performance of the Chief Executive Officer.
10. To ensure the availability of adequate financial resources
11. To be accountable to its shareholder for FFPC's performance.
12. To set the salaries and compensation of management.
13. To approve the selection of the external auditors and the related remuneration and terms of engagement.

Board Meetings

The following table summarizes FFPC's Board meeting calendar for the 2013 calendar year:

Table 1.5.9: FFPC Board of Directors 2013 Calendar of Events

FFPC Board of Directors 2013 Calendar of Events	
Event	Date
Board of Directors Meetings	Thursday, February 07, 2013
Board of Directors Meetings	Thursday, April 04, 2013
Board of Directors Meetings	Friday, April 26, 2013
Annual General Meeting	Wednesday, May 01, 2013
Board of Directors Meetings	Thursday, May 16, 2013
Board of Directors Meetings	Thursday, June 20, 2013
Board of Directors Meetings	Thursday, July 18, 2013
Board of Directors Meetings	Thursday, August 15, 2013
Board of Directors Meetings	Thursday, September 19, 2013
Board of Directors Meetings	Thursday, October 24, 2013
Board of Directors Meetings	Thursday, November 21, 2013
Board of Directors Meetings	Thursday, December 19, 2013

Orientation and Continuing Education

FFPC's Board of directors have access to continuing education on an as needed basis. The Board is built on a solid foundation of experience, as the combined years of service in the industry exceed 150 years. Recent continued education sessions included Corporate Governance, Basic computing and Bill 168 Workplace Violence and Harassment training. As part of FFPC's strategic improvement plan, all Board members will be granted access to a personal laptop computer equipped with Microsoft Office productivity suites, access to corporate email accounts and files, as well as to the internet.

In the past, FFPC frequently circulated paper copies of all relevant industry correspondence to all Directors such as newsletters, reports, publications, and announcements, and pertinent

correspondence including management update reports. With the shift to electronic circulation of this information, FFPC will significantly reduce its consumption of paper, as well as be able to provide Directors with more timely information.

Additional benefits include improved access to industry information. For example, the EDA's Weekly newsletter provides Directors with a "Coles Notes" version of all pertinent industry developments. Many of the articles within the newsletter contain hyperlinks that direct the reader to the supporting documentation regarding the article with the click of a mouse. As such, FFPC's Directors will have greatly enhanced access to information at their fingertips.

FFPC's Board members also participate in Visioning Session retreat every second year. The one day session is used to assess corporate performance, review and revise corporate goals and objectives, as well as to revise the strategic plan.

Directors also attend industry events on a rotational basis, such as the EDA's Annual General Meeting which is followed by the EDIST (Electricity Distribution, Information Systems & Technology) Conference and Exhibition, as well as various other regional industry forums, to network with industry colleagues and to stay connected with industry developments.

Ethical Business Conduct

To date FFPC has not adopted a formal written code with respect to ethical business conduct; however, FFPC has adopted the following Health and Safety Policy that addresses conduct and expectations in the workplace:

Health and Safety Policy

The Fort Frances Power Corporation is committed to the safety of its employees and of the public in general. The health, safety and well being of every employee are of primary importance and our ultimate objective is to eliminate all injures and losses both at work and at home.

General

It is our aim to design a system that can be operated and maintained safely by and for our employees and the customers we serve.

We will inform customers of potential hazards and promote safety awareness in the community.
The Fort Frances Power Corporation is committed to providing its employees with:

- *A safe, healthy and fulfilling work environment that is free from violence and harassment, in accordance with industry standards and in compliance with legislative requirements.*
- *Suitable training and appropriate tools and equipment to enable them to perform their work in a safe and efficient manner.*

Each employee is expected to utilize the training, tools and equipment provided to best advantage. In addition, each employee must consider it a personal responsibility to maintain a positive attitude with respect to health and safety matters and to promote and follow safe work practices at all time.

The Fort Frances Power Corporation and employees will adhere to the rules of the Infrastructure Health and Safety Association of Ontario (formerly known as EUSA), all applicable Health and Safety legislation and our own specific health and safety guidelines and work procedures, along with applicable industry standards.

Responsibilities

Chief Executive Officer:

- *Will provide policy direction and planning keeping with the spirit of current Health and Safety legislation and will hold supervisors accountable for the proper day-to-day safe work operations.*

General Superintendent:

- *Will ensure all employees are properly trained and that correct work procedures are followed.*
- *Work together with the employee representative to regularly inspect work site and premises.*
- *Communicate all relevant information concerning hazards or unsafe procedures.*
- *Hold accountable all employees for any unsafe practice or violation of the Infrastructure Health and Safety Association of Ontario rules or all applicable Health and Safety legislation and regulation.*

All Employees:

- *Will comply with Fort Frances Power Corporation Policies and Procedures, the Infrastructure Health and Safety Association of Ontario rules and all applicable Health and Safety legislation and regulation, along with applicable industry standards.*

Nomination of Directors

FFPC's Board of Directors serve as Board members for a term of three years. Upon the expiration of the three year term, a Board of Director "Personnel Selection Committee", is assembled, that is responsible for filling the vacancy. Directors are allowed to reapply to serve consecutive terms; however, they must compete against other all candidates identified through a public call of interest. The Personnel Selection Committee is responsible for coordinating public notices, for screening and scoring all applicants according to a skills matrix, and for recommending the best suited candidate to the Shareholder for formal approval. The following newspaper clipping depicts FFPC's 2010 public notice to fill Board of Director vacancies.



FFPC

FORT FRANCES POWER CORPORATION

PUBLIC NOTICE

Fort Frances Power Corporation
Board of Directors

The Fort Frances Power Corporation invites interested residents of the Town of Fort Frances to consider serving as a member of the Fort Frances Power Corporation Board of Directors.

The Fort Frances Power Corporation is a private corporation responsible for the distribution of electricity within the Town of Fort Frances. It is regulated by the Ontario Energy Board and governed by the Board of Directors.

We are looking for individuals who have a strong knowledge of the electricity industry, the Ontario regulatory system and the business environment.

Applicants must be 18 years of age or older. Application screening will be performed on a merit based process, with regards to relevant qualifications and experience.

Resumes to be submitted no later than **Friday, September 10, 2010 at 4:00 p.m.** to:

Attn: Personnel Selection Committee
Fort Frances Power Corporation
320 Portage Avenue
Fort Frances, Ontario
P9A 3P9

Board Committees

FFPC's Board of Directors as a whole performs the duties of the following committees:

- Human Resources Committee
- Finance and Audit Committee
- Nominating & Governance Committee

Human Resources Committee:

The Human Resources Committee is responsible for succession planning, performance management plans, compensation and benefit programs, strategic planning of human resource related policies and the organizational development plan.

Finance and Audit Committee

The Finance and Audit Committee is responsible for monitoring and overseeing FFPC's financial accounting and reporting and the external audit process. To the best of FFPC's knowledge and understanding, the Finance and Audit Committee members are independent and financially literate, and as such are deemed competent to fulfill their fiduciary responsibility.

Governance Committee

The Nominating & Governance Committee is responsible for making recommendations regarding the composition of the Board of Directors, operations and performance; overseeing the Company's CEO succession planning process; developing corporate governance principles; and helping shape the corporate governance of the company.

Personnel Selection Committee

The Personnel Selection Committee is responsible for assessing and nominating members of the board of directors.

Transmission Assets

FFPC's Municipal Transformer Station ("FFMTS") is a greater than 50 kV transformer station. Legacy accounting had categorized FFMTS as a distribution station and as represented on FFPC's Capital Asset continuity schedules. In 2012, FFPC corrected this error and transferred this asset to the correct USoA account 1815.

FFPC is seeking approval to continue to deem the high voltage station as a distribution asset.

Accounting Standard Used

Consistent with the Board's letter issued April 30, 2012 entitled Impact of the Decision to Defer the Mandatory Date for the Implementation of International Financial Reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board, this application has been prepared using Canadian Generally Accepted Accounting Principles (CGAAP) with new depreciation rates and capitalization policies (New CGAAP). In accordance with the Filing Requirements, FFPC has provided information for the historic years 2006-2012 in CGAAP, the 2013 Bridge Year in CGAAP and New CGAAP and the 2014 in New CGAAP.

FFPC did amend its cost capitalization policy to be consistent with CGAAP in the treatment of depreciation rates only, as FFPC has not capitalized labour in any part of its self-constructed assets. This change has impacted the 2014 rate base and the 2014 distribution revenue requirement. FFPC has provided detailed explanations of this change in the applicable section of the application.

Deviations From Filing Requirements

Fort Frances Power Corporation has not, to the best of its knowledge, deviated from Chapter 2 of the Board's *Filing Requirement for Electricity Distribution Rate Applications,* issued July 17, 2013 and Chapter Five of the Ontario Energy Board's *Filing Requirements for Transmission and Distribution Applications* issued on March 28, 2013.

Changes in Methodology

FFPC has not changed any methodologies used in previous applications. However, FFPC has amended its depreciation rates in this Application.

In February 2013, the Accounting Standards Board (the "AcSB") announced a deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities to January 1, 2015, after three previous one-year deferrals. The decision to extend the deferral date to January 1, 2015 was made in light of the continued uncertainty surrounding the treatment of regulatory accounts. Discussions at the International Accounting Standards Board (the "IASB") indicate that it expects to issue an interim standard on regulatory accounting by the end of the 2014.

On April 30, 2012, the Board issued a letter entitled "*Impact of the Decision to Defer the Mandatory Date for the Implementation of International Financial Reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board"*). The Board provided guidance for all electricity utilities regarding the impact of the decision by AcSB to defer the mandatory changeover to IFRS to January 1, 2013. In its letter, the Board clarified that it would not require regulatory accounting and reporting for 2012 to be in MIFRS if a distributor is not required to adopt IFRS for financial reporting and opts to remain on CGAAP.

However, on July 17, 2012, the Board issued a letter entitled *Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013.* In its letter, the Board provided direction on the option to defer IFRS changeover in 2012.

The Board advised distributors that changes to depreciation rates and capitalization policies that would have been implemented under IFRS could be made in 2012 under CGAAP (i.e. effective January 1, 2012), and must be made no later than 2013 (i.e. effective January 1, 2013), regardless of whether the AcSB permits further deferrals beyond 2012 for the changeover to IFRS.

FFPC has elected to continue to prepare its financial statements under CGAAP. In accordance with the Board's guidelines published July 17, 2012, FFPC has implemented changes to its depreciation rates and capitalization policy effective January 1, 2013. FFPC did not include a labour or overhead cost components in previously built self-constructed assets, so no changes will be made in the asset values for FFPC.

These CGAAP statements, prepared using the new depreciation rates and capitalization policy will be referred to as New CGAAP. FFPC is not planning to transition of IFRS until January 1, 2015 and used USoA Account 1576 – Accounting Changes under CGAAP to record the required accounting changes from revised depreciation expenses.

Changes in Depreciation Rates

FFPC contracted BDO Canada LLP, Advisory Services to perform a cost allocation on FFPC's current capital assets valuation. This reassessment normalized individual capital asset amounts to industry standards based on a completed listing of Property Plant and Equipment available in FFPC's GIS system.

FFPC is adjusting individual capital assets of the USoA 1830-1840 as shown in the table below in 2013. FFPC would like to note that the total asset valuation did not change, only the allocation, as the total net book value for USoA 1830-1840 remained constant at $1,658,514.

Table 1.5.10: Cost Allocation of FFPC's USoA Accounts 1830, 1835, 1840 and 1845

BDO Canada LLP. Cost Allocation Summary for Fort Frances Power Corporation, as at December 31, 2012							
		Original (prior to allocation)			Revised (following cost allocation)		
Account	Asset Type	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
1830	Poles, Towers, Fixtures	$ 5,169,630	$ 3,985,630	$ 1,184,000	$ 3,308,296	$ 2,128,537	$ 1,179,759
1835	OH Conductor	$ 401,309	$ 750	$ 400,558	$ 1,622,789	$ 1,360,441	$ 262,348
1845	UG Conductor	$ 97,937	$ -	$ 97,937	$ 427,295	$ 302,332	$ 124,963
1840	Underground Conduit	$ 2,183	$ 26,163	$ (23,980)	$ 312,678	$ 221,235	$ 91,443
		$ 5,671,059	**$ 4,012,543**	**$ 1,658,515**	**$ 5,671,058**	**$ 4,012,544**	**$ 1,658,514**
				Completed by Ziad Akkaoui, Advisory Services, BDO Canada LLP.			
Note 1 - as assets are 71% depreciated, it is assumed that the allocation will utilize the same accumulated depreciation.							

FFPC recently developed its first formal Asset Management Policy and Process. The development process assigned "Adopted Useful Life" values to asset classes, largely based on the "Typical Useful Life" values as per the "Kinectrics Report". Based on asset age and condition profile FFPC was able to establish "Remaining Useful Life" values at the individual asset level, as well as at the overall asset class level, relative to FFPC's "Adopted Useful Life". The "Remaining Useful Life" is used to establish the period of time over which the remaining value of the asset is amortized.

FFPC has revised its capitalization policy to be consistent with CGAAP and has applied deprecation rates consistent with the Kinectric's study but adjusted, when necessary, to reflect FFPC's Asset Management Policy. Further information regarding the 'Adopted Useful Life' can be found in Exhibit 2.

The following table summarizes FFPC's assets owned, as well as the associated "Adopted Useful Life", relative to the "Kinectrics Report".

Table 1.5.11: FFPC's Components and Adopted Useful Life

FFPC Summary of Assets Owned									
			Asset Details		Kinectrics Useful Life			Useful Life Assessment	
Parent*	USoA Account #	#	Category| Component | Type		MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to FFPC Adopted UL
OH	1830	1	Fully Dressed Wood Poles	Overall	35	45	75	45	23.21
		4	OH Line Switch (Expressed as sets of 3 Phase Switches)		30	45	55	45	20.66
	1835	8	OH Conductors	Primary Conductor	50	60	75	60	26.23
	1855			Secondary Conductor	25	35	40	40	12.00
	1850	9	OH Transformers		30	40	60	40	11.21
TS & MS		12	Power Transformers	Overall	30	45	60	58	20.00
	1815			Bushing	10	20	30	44	6.00
	(all)			Tap Changer	20	30	60	58	20.00
		13	Station Service Transformer		30	45	55	45	5.00
		15	Station DC System	Overall	10	20	30	29	6.00
				Battery Bank	10	15	15	15	6.00
				Charger	20	20	30	29	6.00
		16	Station Metal Clad Switchgear	Overall	30	40	60	62	17.00
				Removable Breaker	25	40	60	62	17.00
		17	Station Independent Breakers		35	45	65	71	4.00
		18	Station Switch		30	50	60	62	21.00
		19	Electromechanical Relays		25	35	50	45	9.00
		21	Digital & Numeric Relays		15	20	20	20	18.50
		22	Rigid Busbars		30	55	60	62	26.00
		23	Steel Structure		35	50	90	62	26.00
UG	1840	29	Primary TR XLPE Cables in Duct		35	40	55	40	12.93
	1855	31	Secondary Cables Direct Buried		25	35	40	35	7.00
	1850	34	Pad-Mounted Transformers	Single Phase	25	40	45	40	12.30
	1850			Three Phase	25	40	45	40	19.95
	1850	36	UG Foundation		35	55	70	80	52.48
	1840	40	Ducts		30	50	85	80	52.05
	1840	41	Concrete Encased Duct Banks		35	55	80	80	46.54
	1840	42	Cable Chambers		50	60	80	60	39.60
General Plant	1915	1	Office Equipment		5-15			5-20	Various
	1930	2	Vehicles	Trucks & Buckets	5-15			15	7.00
				Trailers	5-20			20	-6.00
	1908	3	Administrative Buildings		50-75			75	30.00
	1910	4	Leasehold Improvements (Generator)		20			20	15.00
	1808	5	Station Buildings	Station Buildings	50-75			62	23.00
				Parking	25-30			30	6.00
				Fence	25-60			62	20.00
				Roof	20-30			40	1.00
	1920	6	Computer Equipment	Hardware	3-5			5	Various
	1611			Software	2-5			5	Various
	1940	7	Equipment	Power Operated	5-10			7	Various
	1940			Tools, Shop, Garage Eq	5-10			10	Various
	1945			Measurement &	5-10			8	Various
				Wireless	2-10			10	Various
	1860	11	Wholesale Energy Meters		15-30			9	4.00
	1860	12	Current & Potential Transformer (CT & PT)		35-50			40	Various
	1860	13	Smart Meters		5-15			15	10.08
	1860	15	Data Collectors - Smart Metering		15-20			17	12.00

Impact on Revenue Requirement

The impact of the changes to depreciation rates is estimated to decrease the revenue requirement by $114,732 in the 2014 Test Year due to lower depreciation expense, as FFPC has adopted extended useful lives for several asset classes.

The impact on rate base and net fixed asset as a result of FFPC' changes to methodology is discussed in further detail in Exhibit 2. The impact on OM&A will be discussed further in Exhibit 4. FFPC completed Appendix 2-YB- Summary of Impacts to Revenue Requirement from Accounting Changes under CGAAP below.

Table 1.5.12: Impact on Revenue Requirement

Summary of Impacts to Revenue Requirement from Accounting Changes under CGAAP or ASPE

Revenue Requirement Component	2014 CGAAP or ASPE with the changes to the policies	2014 CGAAP without the changes to the policies	Difference	Reasons why the revenue requirement component is different under CGAAP or ASPE with the changes to the policies versus CGAAP without the changes to the policies
Closing NBV 2013	$ 3,398,029	$ 3,283,297	$ 114,732	Change in useful lives and capitalization policy
Closing NBV 2014	$ 3,939,746	$ 3,730,747	$ 208,999	Change in useful lives and capitalization policy
Average NBV	$ 3,668,888	$ 3,507,022	$ 161,866	Change in useful lives and capitalization policy
Working Capital	$ 475,877	$ 455,913	$ 19,964	Impact of Change in OM&A
Rate Base	$ 4,144,765	$ 3,962,935	$ 181,830	
Return on Rate Base	$ 135,041	$ 135,041	$ -	
			$ -	
OM&A	$ 1,657,650	$ 1,657,650	$ -	
Depreciation	$ 216,296	$ 331,028	-$ 114,732	Reduction due to change in useful lives and capitalization policy
PILs or Income Taxes	$ -	$ -	$ -	
			$ -	
Less: Revenue Offsets	-$ 103,033	-$ 103,033	$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s)			$ -	
Total Base Revenue Requirement	$ 1,905,954	$ 2,020,686	-$ 114,732	

Non-Utility Business

FFPC currently does not own any Renewable Generation Assets.

FFPC does participate in the delivery of the Ontario Power Authority's conservation and demand management programs and the accounting for these activities is totally separate from FFPC's rate regulated activities and in accordance with the Board's Accounting Procedures Handbook For Electricity Distributors.

Any work-for-others or recoverable job for others is fully cost recoverable.

Status of Board Directives from Previous Board Decisions

FFPC filed a Cost of Service Application with the Board on September 30, 2005 under the 2006 Electricity Distribution Rate ("EDR"), EB-2005-0366. Board Decision approved a revenue requirement of $1,436,628.

With approval from the Board, FFPC has deferred filing subsequent cost of service applications until this Application, which will affect rates for May 1, 2014.

Directives from Stand Alone Smart Meter Application (EB-2012-0327)

In its Decision and Order in FFPC's Smart Meter Application (EB-2012-0327), the Board directed FFPC to record capital and operating costs for new smart meters and the operations of smart meters in regular capital and operating expense accounts.

The Board also instructed FFPC to transfer existing Stranded Meter assets and to continue tracking costs and to bring forward those costs within the next Cost of Service Application. FFPC has complied with the Board's directives and is seeking disposition of the stranded meter sub-account in Exhibit 9 in this Application.

Conditions of Service

Fort Frances Power Corporation's Conditions of Service is available on our website at http://ffpc.fort-frances.com.

There are no changes to FFPC's Conditions of Service as a result of this Application.

Response to Letters of Comment

FFPC will respond to any matters that are raised in letter of comment filed with the Board during the course of this proceeding and file those responses as additional evidence.

APPENDIX A

Fort Frances Power Corporation

Audited Financial Statements For the Years 2011 and 2012

AMENDED

Fort Frances Power Corporation
Financial Statements
For the year ended December 31, 2011

Contents

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BDO

Tel: 807 274 9848
Fax: 807 274 5142
www.bdo.ca

BDO Canada LLP
375 Scott Street
Fort Frances ON P9A 1H1 Canada

AMENDED

Independent Auditor's Report

To the Shareholder of
Fort Frances Power Corporation

We have audited the accompanying financial statements of the Fort Frances Power Corporation as at December 31, 2011, which comprise the Balance Sheet as at December 31, 2011, and the Statement of Operations and Deficit and Statement of Cash Flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly in all material respects, the financial position of the Fort Frances Power Corporation as at December 31, 2011, and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO CANADA LLP

Chartered Accountants, Licensed Public Accountants

Fort Frances, Ontario
April 26, 2012, except for the amendment described in Note 1, which is as of September 7, 2012.

BDO Canada LLP, a Canadian limited liability partnership, is a member of BDO International Limited, a UK company limited by guarantee, and forms part of the international BDO network of independent member firms.

Fort Frances Power Corporation
Balance Sheet

December 31	2011	2010
Assets		
Current		
Cash	$ 212,248	$ 667,980
Investments (Note 2)	2,966,569	1,425,697
Accounts receivable (Note 3)	931,745	2,478,773
Unbilled revenue	933,203	890,711
Inventory	117,174	119,690
Prepaid expense	35,956	44,814
Recoverable income taxes	18,585	8,780
	5,215,480	5,636,445
Property, plant and equipment (Note 4)	2,870,592	3,074,231
Regulatory assets (Note 8)	815,879	819,928
Future income tax assets (Note 7)	227,762	224,413
	$ 9,129,713	$ 9,755,017
Liabilities		
Current		
Accounts payable and accrued liabilities (Note 5)	$ 2,285,547	$ 2,983,952
Customer deposits	55,887	65,197
Deferred revenue	63,729	1,652
	2,405,163	3,050,801
Employee future benefits	132,620	114,568
Regulatory liabilities (Note 8)	983,964	976,247
	3,521,747	4,141,616
Shareholder's equity		
Share capital (Note 6)	5,807,391	5,807,391
Deficit	(199,425)	(193,990)
	5,607,966	5,613,401
	$ 9,129,713	$ 9,755,017

On behalf of the Board:

Director

Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Fort Frances Power Corporation
Statement of Operations and Deficit

For the year ended December 31	2011	2010
Service revenue		
Residential	$ 3,820,483	$ 3,606,922
General	3,726,343	3,494,609
Street lighting	106,818	95,321
Reconnection charges	5,220	6,371
Special purpose charges	-	18,810
	7,658,864	7,222,033
Cost of power	6,213,358	5,722,105
Gross margin on service revenue	1,445,506	1,499,928
Other operating revenue (Note 9)	351,635	369,592
	1,797,141	1,869,520
Operating and maintenance expense	460,162	554,731
Billing and collection	213,984	264,158
General and administrative expense	743,694	677,044
Amortization	333,632	357,117
Interest	74,816	6,978
	1,826,288	1,860,028
Net income (loss) before the following	(29,147)	9,492
Gain (loss) on disposal of assets	5,127	(1,220)
Income taxes		
Current recovery (expense)	18,585	8,780
Net income (loss) for the year	(5,435)	17,052
Deficit, beginning of year	(193,990)	(211,042)
Deficit, end of year	$ (199,425)	$ (193,990)

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Fort Frances Power Corporation
Statement of Cash Flows

For the year ended December 31	2011	2010
Cash provided by (used in)		
Operating activities		
Net income (loss) for the year	$ (5,435)	$ 17,052
Item not involving cash		
Amortization	333,632	357,117
	328,197	374,169
Changes in non-cash working capital balances		
Accounts receivable	1,546,368	(1,689,313)
Unbilled revenue	(42,491)	47,948
Inventory	2,516	15,068
Prepaid	8,859	(23,312)
Regulatory assets	4,050	(176,265)
Accounts payable	(697,745)	2,179,256
Deferred revenue	62,076	(5,348)
Current income taxes	(9,805)	(8,314)
Future income taxes	(3,349)	(10,423)
Regulatory liabilities	7,716	(59,334)
Employee future benefits	18,052	4,853
	1,224,444	648,985
Investing activities		
Acquisition of property, plant and equipment	(129,993)	(521,827)
Decrease (increase) in investments	(1,540,872)	239,113
	(1,670,865)	(282,714)
Financing activities		
Decrease in customer deposits held	(9,311)	(8,861)
Increase (decrease) in cash during the year	(455,732)	357,410
Cash, beginning of year	667,980	310,570
Cash, end of year	$ 212,248	$ 667,980

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Fort Frances Power Corporation
Summary of Significant Accounting Policies

December 31, 2011

Nature of Business

On June 19, 2000, Fort Frances Power Corporation was incorporated under the Business Corporation Act (Ontario), under the laws of Ontario, created for the purpose of continuing electricity distribution activities. The incorporation was required in accordance with the *Energy Competition Act, 1998*, in the Province of Ontario.

Pursuant to this legislation, under the terms of By-law No. 55/00 of the Town of Fort Frances ("Transfer By-law"), enacted on November 6, 2000, the Town of Fort Frances transferred all employees, assets, liabilities, rights and obligations of the former Fort Frances Public Utilities Commission, in consideration for the issuance of equity securities of Fort Frances Power Corporation.

The Corporation is engaged in the regulated distribution of retail electricity to customers located in the Town of Fort Frances as a Local Distribution Company ("LDC").

Basis of Accounting

Revenues and expenditures are reported on the accrual basis of accounting. The accrual basis of accounting recognizes revenues as they are earned and measurable; expenditures are the cost of goods and services acquired in the period whether or not payment has been made or invoices received.

Regulation

The *Energy Competition Act, 1998*, was given Royal Assent on October 30, 1998, which provided for a competitive market in the generation and sale of electricity and the regulation of the monopoly electricity delivery system in the Province of Ontario (the "Province").

On May 1, 2002, the government of Ontario opened Ontario's wholesale and retail markets to competition by providing generators, retailers and consumers with open access to Ontario's transmission and distribution network ("Open Access").

Since the commencement of Open Access, electricity distributors have been purchasing their electricity requirements from the wholesale market administered by the Independent Electricity System Operator (the "IESO") and recovering the cost of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (the "OEB").

The Ontario Energy Board (the "OEB") has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998*, sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

Regulation (continued) The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution Companies fulfill obligations to connect and service customers.

An LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

(i) *Electricity Price and Related Rebates.* The electricity price and related rebates represent a pass through of the commodity cost of electricity.

(ii) *Distribution Rate.* The distribution rate is designed to recover the costs incurred by an LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

(iii) *Retail Transmission Rate.* The retail transmission rate represents a pass through of the wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

(iv) *Wholesale Market Service Charge.* The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

Market participants (including distributors and retailers) are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations.

Market-based Rate of Return

Before the introduction of rate caps in December 2002, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return.

Regulation (continued) Since the introduction of market based rate of return for Ontario distribution Companies, the Fort Frances Power Corporation has elected to take a 0.0% rate of return on common equity for the Corporation and has operated under the rate minimization model. This is mainly due to the historical agreement with the local paper mill, which has always been a defining characteristic of the utility. As such, the Fort Frances Power Corporation has not applied for any distribution rate increases required to fund a financial rate of return.

Regulatory Developments

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future.

Regulatory Treatments The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian Institute of Chartered Accountants Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation" ("AcG-19"), certain costs and variance account balances deemed to be "regulatory assets" or "regulatory liabilities" in the LDC are reflected separately on the Corporation's balance sheet until the manner and timing of disposition is determined by the OEB.

Effective January 1, 2009, the Corporation adopted amended Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1100 - "Generally Accepted Accounting Principles", Handbook Section 3465 - "Income Taxes", and Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". These amended sections and guidance established new standards and removed a temporary exemption in Handbook Section 1100 pertaining to the application of that section to the recognition and measurement of assets and liabilities arising from rate regulation. The new standards require the recognition of future income tax liabilities and assets in accordance with Handbook Section 3465 as well as a separate regulatory asset or liability balance for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers, and retain existing requirements to disclose the effects of rate regulation. The revised standards are effective for interim and annual financial statements for the fiscal years beginning on or after January 1, 2009.

Regulatory Treatments (continued)

Following the removal of the temporary exemption for rate-regulated operations included in Handbook Section 1100, the Corporation developed accounting policies for its assets and liabilities arising from rate regulation using professional judgement and other sources issued by bodies authorized to issue accounting standards in other jurisdictions.

Upon final assessment and in accordance with Handbook Section 1100, the Corporation determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under Canadian GAAP and this recognition is consistent with U.S. Financial Accounting Standards Board Accounting Standards Codification 980 - "Regulated Operations".

Spare Transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the OEB's Accounting Procedures Handbook (AP Handbook), spare transformers are treated as property, plant and equipment. These assets would be recorded as inventory under Canadian GAAP for unregulated businesses.

Financial Instruments

Effective January 1, 2007, the Corporation adopted the CICA Handbook Sections 3855 - "Financial Instruments - Recognition and Measurement", 3861 - "Financial Instruments - Disclosure and Presentation", 1530 - "Comprehensive Income" and the revised CICA Handbook Section 3251 - "Equity" (the "Handbook Sections"). As provided under the standards, the comparative financial statements have not been restated. These new Handbook Sections have lead to changes in the accounting for financial instruments. All relevant changes are outlined below.

Financial Instruments - Recognition and Measurement - Section 3855

This Section establishes the standards for the recognition and measurement of financial assets and financial liabilities. At inception, all financial instruments which meet the definition of a financial asset or a financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation.

Financial Instruments (continued)

As of January 1, 2007, the Corporation has elected the following balance sheet classifications with respect to its financial assets and financial liabilities:

- Cash and investments are classified as "Assets Held - For Trading" and are measured at fair value.
- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities and customer deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Comprehensive Income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which has not been included in net income.

Unless otherwise noted, it is managements opinion that the Corporation is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair value of these financial instruments approximate their carrying values, unless otherwise noted.

There was no other comprehensive income during the year ended December 31, 2011.

Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on a standard cost basis net of the provision for obsolescence.

Fort Frances Power Corporation
Summary of Significant Accounting Policies

December 31, 2011

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Amortization based on the estimated useful life of the asset is as follows:

Buildings	- 3% straight line basis
Distribution equipment	- various straight line basis
Other equipment	- 10% straight line basis
Computer equipment and software	- 20 & 100% straight line basis
Automotive equipment	- various straight line basis
Office equipment	- 10% straight line basis
Leasehold improvements	- 20% straight line basis

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, bank balances and investments in money market instruments and bond funds with maturities of three months or less.

Revenue Recognition

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills. Deposits expected to be refunded within the next fiscal year are classified as a current liability.

Use of Estimates

The preparation of the financial statements in accordance with GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and their reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

The estimates used in the preparation of these financial statements include, the useful lives of property, plant and equipment, regulatory assets and liabilities and accrued liabilities.

Fort Frances Power Corporation
Summary of Significant Accounting Policies

December 31, 2011

Impairment of Long-lived Assets

Long-lived assets held and used by the Corporation are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If changes in circumstances indicate that the carrying amount of an asset that an entity expects to hold and use may not be recoverable, future cash flows expected to result from the use of the asset and its disposition must be estimated. If the undiscounted value of the future cash flows is less than the carrying amount of the asset, impairment is recognized. Management believes that there has been no impairment of any of the Corporation's long-lived assets as at year end.

Payments in Lieu of Taxes

The Corporation is required to compute taxes under the Income Tax Act and Ontario Corporations Tax Act and remit such amounts thereunder to the Ontario Electricity Financial Corporation. These amounts referred to as Payments in Lieu of Taxes under the Energy Competition Act, are applied to reduce certain debt obligations of the former Ontario Hydro.

Future Income Taxes

Commencing January 1, 2003, the Corporation adopted the liability method of accounting for income taxes as outlined in the provisions of Section 3465 of the Handbook of the Canadian Institute of Chartered Accountants. Under this method, current income taxes are recognized for the estimated income taxes payable for the current year. Future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized.

Employee Future Benefits

Employee future benefits provided by the Corporation include accumulated sick leave and vacation credits. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

Capital Disclosures

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 1535 - "Capital Disclosures" which requires disclosure of the Corporation's objectives, policies and processes for managing capital as well as its compliance with any external capital requirements. The implementation of this standard did not have any impact on the Corporation's results of operations or financial position.

New Accounting Pronouncement

International Financial Reporting Standards ("IFRS")

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date.

The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. At this time, the Corporation believes that the impact on its financial statements could be material.

On September 10, 2010, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board ("IASB") in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. Subsequently, the Canadian Securities Administrators announced that entities subject to rate regulation may defer the adoption of IFRS for up to one year, consistent with the one year deferral granted by the AcSB.

On March 21, 2011, the AcSB granted an additional optional one year deferral for the adoption of IFRS. The additional deferral was made in light of the increased possibility that the IASB may address rate-regulated activities as part of its future agenda and develop interim guidance in the meantime that, in effect, would allow the continuation of accounting practices in accordance with pre-changeover standards in Part V of the handbook.

The Corporation did not adopt IFRS for the year ended December 31, 2011 as the mandatory adoption for entities with activities subject to rate regulation was deferred to fiscal years beginning on or after January 1, 2012. The Accounting Standards Board has recently decided that the mandatory adoption of IFRS for such entities will be deferred an additional year. The Corporation is still considering its options and has not yet decided whether it will adopt IFRS in 2012 or 2013. Accordingly, the Corporation will continue to prepare its financial statements in accordance with Canadian GAAP accounting standards in Part V of the CICA Handbook for 2011.

New Accounting Pronouncement (continued)

As a result of these developments related to IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Corporation cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operations. Although the Corporation has completed a detailed assessment of the accounting and disclosure differences between Canadian GAAP and IFRS, in light of the one-year deferral, this assessment will be revisited due to changes to standards during this period. The Corporation will continue to actively monitor IASB developments with respect to RRA and non-RRA IFRS developments and their potential impacts.

Fort Frances Power Corporation
Notes to Financial Statements

December 31, 2011

1. Prior Period Error Correction

Local Distribution Corporation's ("LDC's") have a choice of using the billed method (cash method) or the accrual method to record the variances in all RSVA accounts. The Corporation has chosen to use the accrual method. As a result, all regulatory variance accounts should be accounted for on a consistent basis using the accrual method. During the year, it was identified that the Global Adjustment regulatory variance account had not been recorded on an accrual basis. The Corporation has corrected for this error by recognizing a prior period adjustment of $298,846 equal to the Global Adjustment credits receivable to the Corporation at December 31, 2010. The adjustment has resulted in a prior period increase of $298,846 to the Corporation's regulatory liabilities and a prior period decrease of $298,846 to the Corporation's accounts payable and accrued liabilities. The adjustment had no effect on the Corporation's prior period net income or shareholder's equity.

Prior to the identification and correction of this prior period adjustment, the Corporation had submitted a rate application to the Ontario Energy Board for the recovery/disbursement of the Corporation's regulatory assets/liabilities. This application was based on the Corporation's December 31, 2010 regulatory asset/liability balances. The application did not reflect the impact of the prior period adjustment noted above.

The Ontario Energy Board approved the disposition of regulatory liability balances as at December 31, 2010 on a final basis in its Decision [EB-2011-0146] dated April 19, 2012. The approved regulatory liability balances did not include the prior period adjustment of $298,846. The prior period adjustment does not change the disposed balances as at December 31, 2010 approved by the Ontario Energy Board. The disbursement of the $298,846 settlement variance will be sought by the Corporation in a future rate application and will be dependant on the approval of the Ontario Energy Board. Should any amount not be approved, the resulting adjustment will be recognized in the Corporation's operations in the year of resolution.

The above note has been amended to facilitate the Corporation's disclosure of out-of-period adjustments for the Ontario Energy Board.

2. Investments

	2011	2010
Money market and bond mutual funds	$ 1,466,569	$ 1,425,697
Guaranteed investment certificate, interest at 1.15%, matures May 11, 2012	1,500,000	-
	$ 2,966,569	$ 1,425,697
Market value	$ 2,966,569	$ 1,425,697

Money market and bond mutual funds have effective interest rates of 1.51% to 3.49% (2010 - 1.24% to 3.61%). Fair values are considered to approximate market values.

3. Accounts Receivable

	2011	2010
Electrical energy	$ 652,204	$ 519,587
Own municipality	4,368	-
Sundry	275,173	230,207
Global adjustment charge cost recovery	-	1,728,979
	$ 931,745	$ 2,478,773

4. Property, Plant and Equipment

			2011	2010
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 100,000	$ -	$ 100,000	$ 100,000
Buildings	1,217,651	981,042	236,609	243,826
Distribution equipment	8,176,903	6,012,396	2,164,507	2,301,366
Other equipment	160,416	133,082	27,334	32,982
Automotive equipment	696,397	457,502	238,895	281,071
Computer equipment and software	74,237	58,894	15,343	20,745
Office equipment	117,407	99,998	17,409	21,201
Leasehold improvements	86,122	15,627	70,495	73,040
	$ 10,629,133	$ 7,758,541	$ 2,870,592	$ 3,074,231

At December 31, 2011, net book value of stranded meters related to the deployment of smart meters amounting to $130,573 (2010 - $118,795) is included in property, plant and equipment. In the absence of rate regulation, property, plant and equipment would have been $130,573 lower at December 31, 2011 (2010 - $118,795).

5. Accounts Payable and Accrued Liabilities

	2011	2010
Trade accounts payable	$ 2,285,547	$ 2,983,292
Own municipality	-	660
	$ 2,285,547	$ 2,983,952

Accounts payable and accrued liabilities include an accrual in the amount of $1,262,902 (2010 - $1,918,399). This represents the identified surplus for the year ending December 31, 2011, as a result of the power agreement. This surplus is to be dispensed to the ratepayers in the form of a credit rebate subsequent to year end.

6. Share Capital

The authorized share capital of the Corporation is an unlimited number of common shares.

Issued share capital is as follows:

		2011	2010
5,807,391	Common shares	$ 5,807,391	$ 5,807,391

7. Future Income Tax Assets

The components of the future income tax assets at December 31 are as follows:

	2011	2010
Property, plant and equipment	$ 219,289	$ 216,137
Employee future benefits	7,629	7,122
Other taxable temporary differences	844	1,154
	$ 227,762	$ 224,413

8. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2011	2010
Smart meters	$ 785,666	$ 777,964
Deferral account for OEB annual cost assessment	8,284	23,392
Special purpose charges	2,270	13,918
Other	19,659	4,654
	$ 815,879	$ 819,928

Regulatory liabilities consist of the following:

	2011	2010
Settlement variances	$ 756,202	$ 751,834
Future income taxes	227,762	224,413
	$ 983,964	$ 976,247

The regulatory assets and liabilities balances of the Corporation are defined as follows:

(a) Smart meters:

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. The LDC launched its smart meter project shortly following the Province of Ontario's announcement in 2006. In 2008, the OEB ordered the LDC to record all future expenditures and revenues related to smart meters to a regulatory asset account and allowed the LDC to keep the net book value of the stranded meters related to the deployment of smart meters in its rate base. The deferred balances continue to be calculated and attract carrying charges.

8. **Regulatory Assets and Liabilities** (continued)

In connection with its smart meter initiatives, the Corporation has incurred capital costs for the year ended December 31, 2011. As at December 31, 2011, smart meter capital expenditures, net of accumulated depreciation, totalling $687,750 have been recorded to regulatory assets (December 31, 2010 - $713,797). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $687,750 higher as at December 31, 2011 (December 31, 2010 - $713,797).

For the year ended December 31, 2011, smart meter operating expenses of $131,814 (2010 - $74,288), and smart meter depreciation expense of $153,668 (2010 - $97,573) were deferred which would have been expensed under Canadian GAAP for unregulated businesses. In the absence of rate regulation, for the year ended December 31, 2011, operating expenses would have been $57,526 higher (2010 - $74,288) and depreciation expense would have been $56,095 higher (2010 - $28,640).

For the year ended December 31, 2011, smart meter customer revenues of $91,388 were deferred (2010 - $47,125). In the absence of rate regulation, for the year ended December 31, 2011, revenue would have been $91,388 higher (2010 - $47,125 higher).

(b) Settlement variances:

The OEB has allowed the Corporation to defer settlement variances since May 1, 2002. This balance represents the variances between amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Corporation has deferred these recoveries in accordance with the criteria set out in the AP Handbook.

The settlement variances net of recoveries arising after May 1, 2002, are deferred in a regulatory liability account.

Under such regulation, the variances are allowed to be deferred which would be recorded as revenue when incurred under Canadian GAAP for unregulated businesses. In the absence of rate regulation, the cost of power in 2011 would have been $4,368 lower (2010 - $69,757 higher).

The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance has not been determined by the OEB.

8. **Regulatory Assets and Liabilities** (continued)

(c) Special purpose charges:

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge ("SPC") assessment for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Corporation the amount of $32,606 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10 (the "SPC" regulation). In accordance with Section 9 of the SPC Regulation, the Corporation is allowed to recover this balance. As at December 31, 2011, the balance in the account consists of the Corporation's assessment of $32,606 less the recoveries received from customers. In the absence of rate regulation, revenue would have been $11,648 higher (2010 - $13,918 higher) and operating expenses would have been $11,648 higher (2010 - $13,918 higher).

(d) Deferral account for OEB annual cost assessments:

The OEB has allowed the Corporation to defer the OEB annual cost assessments for the fiscal years starting after January 1, 2004. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

(e) Future income taxes:

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

As at December 31, 2011, the Corporation has recorded a future income tax asset of $227,762 (2010 - $224,413) and corresponding regulatory liability of $227,762 (2010 - $224,413).

9. **Other Operating Revenue**

	2011	2010
Investment income	$ 60,746	$ 31,133
Regulatory asset carrying charges	66,091	12,466
Late payment charges	23,669	25,151
Pole rentals	46,784	47,328
OPA grant revenue	38,484	134,362
Miscellaneous revenue	115,861	119,152
	$ 351,635	$ 369,592

10. Related Party Transactions

Fort Frances Power Corporation is owned by the Corporation of the Town of Fort Frances.

	2011	2010
Sales to the Corporation of the Town of Fort Frances	$ 786,091	$ 710,732
Purchased services from the Corporation of the Town of Fort Frances	$ 124,164	$ 150,304

The sales and purchases above were made in the normal course of business and recognized at the exchange amount which is equivalent to fair market value.

11. Credit Facilities

Fort Frances Power Corporation is party to a short-term credit facility with a Canadian chartered bank pursuant to which the Corporation could borrow up to $370,000 in the form of an operating loan. The amount drawn under the credit facility as at December 31, 2011, was $NIL.

12. Financial Guarantees

Participants in the wholesale market for electricity that is administered by the Independent Electricity Market Operator are required to satisfy prescribed prudential requirements.

The Corporation is party to an irrevocable standby letter of credit with a Canadian chartered bank. As at December 31, 2011, the credit amounts to $438,495 (2010 - $438,495). This letter of credit is secured by a general security agreement.

13. Pension Agreements

The Corporation makes contributions to the Ontario Municipal Employees' Retirement Fund (OMERS), a multi-employer plan, on behalf of nine members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. Employees and employers contribute jointly to the plan.

Because OMERS is a multi-employer pension plan, any pension plan surpluses or deficits are a joint responsibility of the Ontario municipal organizations and their employees. As a result, the municipality does not recognize any share of the OMERS pension surplus or deficit. The amount contributed to OMERS for 2011 was $57,717 (2010 - $48,602) for current services. The OMERS Board rate was 7.4% to 10.7% depending on the income level for 2011 (2010 - 6.4% to 13.1% depending on the income level).

14. Capital Disclosures

The Corporation's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of the Fort Frances Power Corporation.
- ensure compliance with covenants related to its credit facilities.

As at December 31, 2011, the Corporation's definition of capital includes shareholder's equity. As at December 31, 2011, shareholder's equity amounts to $5,607,966 (2010 - $5,613,401). There have been no changes in the Corporation's approach to capital management during the year.

15. Risk Factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

The Corporation's activities provide for a variety of financial risks, particularly credit risk and liquidity risk.

Credit risk

Financial instruments are exposed to credit risk as a result of the risk of the counterparty defaulting on its obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risks based on the financial condition and short and long-term exposures to counterparties.

15. **Risk Factors** (continued)

The Corporation's credit risk associated with accounts receivable is primarily related to payments from Fort Frances Power Corporation customers. Fort Frances Power Corporation has approximately 4,000 customers, the majority of which are residential. Fort Frances Power Corporation collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2011, Fort Frances Power Corporation held security deposits in the amount of $55,887 (2010 - $65,197).

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations and deficit. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations and deficit.

At December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. The Corporation attempts to minimize interest rate risk by issuing long-term fixed rate debt.

Under the Corporation's Revolving Credit Facility (Note 11), the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit).

Liquidity risk

The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

Hedging and derivatives risk

As at December 31, 2011, the Corporation has not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at December 31, 2011, the Corporation has limited exposure to the changing values of foreign currencies.

Fort Frances Power Corporation

Financial Statements

For the year ended December 31, 2012

Fort Frances Power Corporation
Financial Statements
For the year ended December 31, 2012

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Fort Frances ON P9A 1H1 Canada

Independent Auditor's Report

To the Shareholder of
Fort Frances Power Corporation

We have audited the accompanying financial statements of the Fort Frances Power Corporation as at December 31, 2012, which comprise the balance sheet as at December 31, 2012, and the statement of operations and deficit and statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly in all material respects, the financial position of the Fort Frances Power Corporation as at December 31, 2012, and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO CANADA LLP

Chartered Accountants, Licensed Public Accountants

Fort Frances, Ontario
April 26, 2013

BDO Canada LLP, a Canadian limited liability partnership, is a member of BDO International Limited, a UK company limited by guarantee, and forms part of the international BDO network of independent member firms.

Fort Frances Power Corporation
Balance Sheet

December 31	2012	2011
Assets		
Current		
Cash	$ 605,125	$ 212,248
Investments (Note 1)	2,350,425	2,966,569
Accounts receivable (Note 2)	833,796	931,745
Unbilled revenue	854,023	933,203
Inventory	123,828	117,174
Prepaid expense	37,656	35,956
Recoverable income taxes	30,189	18,585
	4,835,042	5,215,480
Property, plant and equipment (Note 3)	3,250,364	2,870,592
Regulatory assets (Note 7)	159,306	815,879
Future income tax assets (Note 6)	253,852	227,762
	$ 8,498,564	$ 9,129,713
Liabilities		
Current		
Accounts payable and accrued liabilities (Note 4)	$ 1,850,469	$ 2,285,547
Customer deposits	49,291	55,887
Deferred revenue	106,480	63,729
	2,006,240	2,405,163
Employee future benefits	120,722	132,620
Regulatory liabilities (Note 7)	1,077,549	983,964
	3,204,511	3,521,747
Shareholder's equity		
Share capital (Note 5)	5,807,391	5,807,391
Deficit	(513,338)	(199,425)
	5,294,053	5,607,966
	$ 8,498,564	$ 9,129,713

On behalf of the Board:

Director

Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Fort Frances Power Corporation
Statement of Operations and Deficit

For the year ended December 31	2012	2011
Service revenue		
Sale of energy	$ 7,148,968	$ 6,999,421
Distribution revenue	1,740,337	1,454,142
	8,889,305	8,453,563
Cost of power	7,148,968	7,008,057
Gross margin on service revenue	1,740,337	1,445,506
Other operating revenue (Note 8)	311,550	351,635
	2,051,887	1,797,141
Operating and maintenance expense	762,649	460,162
Billing and collection	255,774	213,984
General and administrative expense	771,980	743,694
Amortization	564,032	333,632
Interest	33,818	74,816
	2,388,253	1,826,288
Net loss before the following	(336,366)	(29,147)
Gain on disposal of assets	-	5,127
Income taxes		
Current recovery	22,453	18,585
Net loss for the year	(313,913)	(5,435)
Deficit, beginning of year	(199,425)	(193,990)
Deficit, end of year	$ (513,338)	$ (199,425)

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Fort Frances Power Corporation
Statement of Cash Flows

For the year ended December 31	2012	2011
Cash provided by (used in)		
Operating activities		
Net loss for the year	$ (313,913)	$ (5,435)
Item not involving cash		
Amortization	564,032	333,632
	250,119	328,197
Changes in non-cash working capital balances		
Accounts receivable	97,949	1,546,368
Unbilled revenue	79,180	(42,491)
Inventory	(6,654)	2,516
Prepaid	(1,700)	8,859
Regulatory assets	656,573	4,050
Accounts payable	(435,078)	(697,745)
Deferred revenue	42,751	62,076
Current income taxes	(11,604)	(9,805)
Future income taxes	(26,090)	(3,349)
Regulatory liabilities	93,585	7,716
Employee future benefits	(11,898)	18,052
	727,133	1,224,444
Investing activities		
Acquisition of property, plant and equipment	(943,804)	(129,993)
Decrease (increase) in investments	616,144	(1,540,872)
	(327,660)	(1,670,865)
Financing activities		
Decrease in customer deposits held	(6,596)	(9,311)
Increase (decrease) in cash during the year	392,877	(455,732)
Cash, beginning of year	212,248	667,980
Cash, end of year	$ 605,125	$ 212,248

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

December 31, 2012

Nature of Business

On June 19, 2000, Fort Frances Power Corporation was incorporated under the Business Corporation Act (Ontario), under the laws of Ontario, created for the purpose of continuing electricity distribution activities. The incorporation was required in accordance with the *Energy Competition Act, 1998*, in the Province of Ontario.

Pursuant to this legislation, under the terms of By-law No. 55/00 of the Town of Fort Frances ("Transfer By-law"), enacted on November 6, 2000, the Town of Fort Frances transferred all employees, assets, liabilities, rights and obligations of the former Fort Frances Public Utilities Commission, in consideration for the issuance of equity securities of Fort Frances Power Corporation.

The Corporation is engaged in the regulated distribution of retail electricity to customers located in the Town of Fort Frances as a Local Distribution Company ("LDC").

Basis of Accounting

Revenues and expenditures are reported on the accrual basis of accounting. The accrual basis of accounting recognizes revenues as they are earned and measurable; expenditures are the cost of goods and services acquired in the period whether or not payment has been made or invoices received.

Regulation

The *Energy Competition Act, 1998*, was given Royal Assent on October 30, 1998, which provided for a competitive market in the generation and sale of electricity and the regulation of the monopoly electricity delivery system in the Province of Ontario (the "Province").

On May 1, 2002, the government of Ontario opened Ontario's wholesale and retail markets to competition by providing generators, retailers and consumers with open access to Ontario's transmission and distribution network ("Open Access").

Since the commencement of Open Access, electricity distributors have been purchasing their electricity requirements from the wholesale market administered by the Independent Electricity System Operator (the "IESO") and recovering the cost of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (the "OEB").

The Ontario Energy Board (the "OEB") has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998*, sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

Regulation (continued) The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution Companies fulfill obligations to connect and service customers.

An LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

(i) *Electricity Price and Related Rebates.* The electricity price and related rebates represent a pass through of the commodity cost of electricity.

(ii) *Distribution Rate.* The distribution rate is designed to recover the costs incurred by an LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

(iii) *Retail Transmission Rate.* The retail transmission rate represents a pass through of the wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

(iv) *Wholesale Market Service Charge.* The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

Market participants (including distributors and retailers) are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations.

Market-based Rate of Return

Before the introduction of rate caps in December 2002, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return.

Regulation (continued) Since the introduction of market based rate of return for Ontario distribution Companies, the Fort Frances Power Corporation has elected to take a 0.0% rate of return on common equity for the Corporation and has operated under the rate minimization model. This is mainly due to the historical agreement with the local paper mill, which has always been a defining characteristic of the utility. As such, the Fort Frances Power Corporation has not applied for any distribution rate increases required to fund a financial rate of return.

Regulatory Developments

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future.

Regulatory Treatments The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian Institute of Chartered Accountants Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation" ("AcG-19"), certain costs and variance account balances deemed to be "regulatory assets" or "regulatory liabilities" in the LDC are reflected separately on the Corporation's balance sheet until the manner and timing of disposition is determined by the OEB.

Effective January 1, 2009, the Corporation adopted amended Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1100 - "Generally Accepted Accounting Principles", Handbook Section 3465 - "Income Taxes", and Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". These amended sections and guidance established new standards and removed a temporary exemption in Handbook Section 1100 pertaining to the application of that section to the recognition and measurement of assets and liabilities arising from rate regulation. The new standards require the recognition of future income tax liabilities and assets in accordance with Handbook Section 3465 as well as a separate regulatory asset or liability balance for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers, and retain existing requirements to disclose the effects of rate regulation. The revised standards are effective for interim and annual financial statements for the fiscal years beginning on or after January 1, 2009.

Regulatory Treatments (continued)

Following the removal of the temporary exemption for rate-regulated operations included in Handbook Section 1100, the Corporation developed accounting policies for its assets and liabilities arising from rate regulation using professional judgement and other sources issued by bodies authorized to issue accounting standards in other jurisdictions.

Upon final assessment and in accordance with Handbook Section 1100, the Corporation determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under Canadian GAAP and this recognition is consistent with U.S. Financial Accounting Standards Board Accounting Standards Codification 980 - "Regulated Operations".

Spare Transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the OEB's Accounting Procedures Handbook (AP Handbook), spare transformers are treated as property, plant and equipment. These assets would be recorded as inventory under Canadian GAAP for unregulated businesses.

Financial Instruments

Effective January 1, 2007, the Corporation adopted the CICA Handbook Sections 3855 - "Financial Instruments - Recognition and Measurement", 3861 - "Financial Instruments - Disclosure and Presentation", 1530 - "Comprehensive Income" and the revised CICA Handbook Section 3251 - "Equity" (the "Handbook Sections"). As provided under the standards, the comparative financial statements have not been restated. These new Handbook Sections have lead to changes in the accounting for financial instruments. All relevant changes are outlined below.

Financial Instruments - Recognition and Measurement - Section 3855

This Section establishes the standards for the recognition and measurement of financial assets and financial liabilities. At inception, all financial instruments which meet the definition of a financial asset or a financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation.

Financial Instruments (continued)

As of January 1, 2007, the Corporation has elected the following balance sheet classifications with respect to its financial assets and financial liabilities:

- Cash and investments are classified as "Assets Held - For Trading" and are measured at fair value.
- Accounts receivable and unbilled revenue are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities and customer deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Comprehensive Income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which has not been included in net income.

Unless otherwise noted, it is managements opinion that the Corporation is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair value of these financial instruments approximate their carrying values, unless otherwise noted.

There was no other comprehensive income during the year ended December 31, 2012.

Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on a standard cost basis net of the provision for obsolescence.

Fort Frances Power Corporation
Summary of Significant Accounting Policies

December 31, 2012

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Amortization based on the estimated useful life of the asset is as follows:

Buildings	- 3% straight line basis
Distribution equipment	- various straight line basis
Other equipment	- 10% straight line basis
Computer equipment and software	- 20 & 100% straight line basis
Automotive equipment	- various straight line basis
Office equipment	- 10% straight line basis
Leasehold improvements	- 20% straight line basis

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, bank balances and investments in money market instruments and bond funds with maturities of three months or less.

Revenue Recognition

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills. Deposits expected to be refunded within the next fiscal year are classified as a current liability.

Use of Estimates

The preparation of the financial statements in accordance with GAAP requires management to make estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and their reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

The estimates used in the preparation of these financial statements include, the useful lives of property, plant and equipment, regulatory assets and liabilities and accrued liabilities.

Impairment of Long-lived Assets

Long-lived assets held and used by the Corporation are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If changes in circumstances indicate that the carrying amount of an asset that an entity expects to hold and use may not be recoverable, future cash flows expected to result from the use of the asset and its disposition must be estimated. If the undiscounted value of the future cash flows is less than the carrying amount of the asset, impairment is recognized. Management believes that there has been no impairment of any of the Corporation's long-lived assets as at year end.

Payments in Lieu of Taxes

The Corporation is required to compute taxes under the Income Tax Act and Ontario Corporations Tax Act and remit such amounts thereunder to the Ontario Electricity Financial Corporation. These amounts referred to as Payments in Lieu of Taxes under the Energy Competition Act, are applied to reduce certain debt obligations of the former Ontario Hydro.

Future Income Taxes

Commencing January 1, 2003, the Corporation adopted the liability method of accounting for income taxes as outlined in the provisions of Section 3465 of the Handbook of the Canadian Institute of Chartered Accountants. Under this method, current income taxes are recognized for the estimated income taxes payable for the current year. Future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized.

Employee Future Benefits

Employee future benefits provided by the Corporation include accumulated sick leave and vacation credits. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

New Accounting Pronouncement

International Financial Reporting Standards ("IFRS")

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date.

The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. At this time, the Corporation believes that the impact on its financial statements could be material.

On September 10, 2010, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board ("IASB") in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. Subsequently, the Canadian Securities Administrators announced that entities subject to rate regulation may defer the adoption of IFRS for up to one year, consistent with the one year deferral granted by the AcSB.

On March 21, 2011, the AcSB granted an additional optional one year deferral for the adoption of IFRS. The additional deferral was made in light of the increased possibility that the IASB may address rate-regulated activities as part of its future agenda and develop interim guidance in the meantime that, in effect, would allow the continuation of accounting practices in accordance with pre-changeover standards in Part V of the handbook. As a result, the Corporation did not adopt IFRS for the year ended December 31, 2011 as the mandatory adoption for entities with activities subject to rate regulation was deferred to fiscal years beginning on or after January 1, 2012.

On February 13, 2013, the AcSB granted another optional deferral for IFRS adoption for entities subject to rate regulation to January 1, 2015. This decision came in light of the uncertainty created by the International Accounting Standards Board ("IASB") in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS.

New Accounting Pronouncement (continued)

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting ("RRA") standards under IFRS and the potential material impact of RRA on the Corporation's financial statements, the Corporation has decided to elect the optional one-year deferral of its adoption of IFRS. Accordingly, the Corporation will continue to prepare its financial statements in accordance with Canadian GAAP accounting standards in Part V of the CICA Handbook for 2012.

As a result of these developments related to IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Corporation cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operations. Although the Corporation has completed a detailed assessment of the accounting and disclosure differences between Canadian GAAP and IFRS, in light of the one-year deferral, this assessment will be revisited due to changes to standards during this period. The Corporation will continue to actively monitor IASB developments with respect to RRA and non-RRA IFRS developments and their potential impacts.

December 31, 2012

1. Investments

	2012	2011
Money market and bond mutual funds	$ 1,486,050	$ 1,466,569
Guaranteed investment certificate, interest at 1.40%, matures May 13, 2013	864,375	1,500,000
	$ 2,350,425	$ 2,966,569
Market value	$ 2,350,425	$ 2,966,569

Money market and bond mutual funds have effective interest rates of 1.11% to 3.07% (2011 - 1.51% to 3.49%).

2. Accounts Receivable

	2012	2011
Electrical energy	$ 583,659	$ 652,204
Own municipality	-	4,368
Sundry	250,137	275,173
	$ 833,796	$ 931,745

3. Property, Plant and Equipment

	Cost	Accumulated Amortization	2012 Net Book Value	2011 Net Book Value
Land	$ 100,000	$ -	$ 100,000	$ 100,000
Buildings	1,228,485	995,749	232,736	236,609
Distribution equipment	8,805,270	6,198,572	2,606,698	2,164,507
Other equipment	162,699	140,014	22,685	27,334
Automotive equipment	696,397	499,677	196,720	238,895
Computer equipment and software	76,907	67,059	9,848	15,343
Office equipment	117,407	103,679	13,728	17,409
Leasehold improvements	86,122	18,173	67,949	70,495
	$ 11,273,287	$ 8,022,923	$ 3,250,364	$ 2,870,592

For the year ended December 31, 2012, $841,418 (2011 - $NIL) in smart meter capital costs were capitalized to property, plant and equipment.

4. Accounts Payable and Accrued Liabilities

	2012	2011
Trade accounts payable	$ 1,068,944	$ 1,018,278
Power agreement credits payable	781,525	1,262,902
	$ 1,850,469	$ 2,281,180

Power agreement credits payable represent the identified surplus for the year ending December 31, 2012, as a result of the power agreement. This surplus is to be dispensed to the ratepayers in the form of a credit rebate subsequent to year end.

5. Share Capital

The authorized share capital of the Corporation is an unlimited number of common shares.

Issued share capital is as follows:

		2012	2011
5,807,391	Common shares	$ 5,807,391	$ 5,807,391

6. Future Income Tax Assets

The components of the future income tax assets at December 31 are as follows:

	2012	2011
Property, plant and equipment	$ 243,425	$ 219,289
Employee future benefits	7,858	7,629
Other taxable temporary differences	2,569	844
	$ 253,852	$ 227,762

7. Regulatory Assets and Liabilities

Regulatory assets consist of the following:

	2012	2011
Smart meters	$ -	$ 785,666
Stranded meters	92,216	-
Deferral account for OEB annual cost assessment	8,288	8,198
Renewable energy projects	32,142	4,406
Special purpose charges	-	2,270
IFRS transition costs	26,660	15,339
	$ 159,306	$ 815,879

Regulatory liabilities consist of the following:

	2012	2011
Variances approved for disposition or recovery	$ 188,095	$ -
Settlement variances	635,602	756,202
Future income taxes	253,852	227,762
	$ 1,077,549	$ 983,964

The regulatory assets and liabilities balances of the Corporation are defined as follows:

(a) Smart meters:

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. The LDC launched its smart meter project shortly following the Province of Ontario's announcement in 2006. In 2008, the OEB ordered the LDC to record all future expenditures and revenues related to smart meters to a regulatory asset account and allowed the LDC to keep the net book value of the stranded meters related to the deployment of smart meters in its rate base.

7. **Regulatory Assets and Liabilities** (continued)

In connection with its smart meter initiatives, the Corporation had incurred $687,750 in capital costs, $131,814 in operating expenses and $153,668 in depreciation expense as at December 31, 2011. The capital costs would have otherwise been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses, while the operating expenses and depreciation expense would have been expensed under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment would have been $687,750 higher, operating expenses would have been $57,526 higher, and depreciation expense would have been $56,095 higher as at December 31, 2011.

For the year ended December 31, 2011, smart meter customer revenues of $91,388 were deferred. In the absence of rate regulation, for the year ended December 31, 2011, revenue would have been $91,388 higher.

On November 8, 2012, the Ontario Energy Board approved the allocation of smart meter capital costs to property, plant and equipment and the allocation of smart meter operating costs, depreciation and revenues to the Corporation's December 31, 2012 revenues and operating expenses.

(b) Stranded meters:

In its November 8, 2012 Decision and Order regarding the allocation of smart meter costs, the OEB also approved the allocation of stranded meter costs, related to the deployment of smart meters, from property, plant and equipment to a stranded meter regulatory asset account. As at December 31, 2012, the net book value of stranded meters related to the deployment of smart meters amounting to $92,216 was included in the Corporation's regulatory assets. As at December 31, 2011, the net book value of stranded meters related to the deployment of smart meters amounting to $130,573 was included in property, plant and equipment.

(c) Variances approved for disposition or recovery:

Variances approved for disposition or recovery consists of balances of regulatory assets or regulatory liabilities approved for disposition or recovery by the OEB through rate riders. The variances approved for disposition or recovery are subject to carrying charges following the OEB prescribed methodology and related rates.

On April 19, 2012, the OEB approved the disposition of net regulatory liabilities of $418,838, consisting of credit balances for settlement variances and other deferred costs and payments-in-lieu of tax (PIL) variances of $389,236 and $29,602, respectively, over a one-year period commencing May 1, 2012.

7. **Regulatory Assets and Liabilities** (continued)

(d) Settlement variances:

Settlement variances represent the variances between amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Corporation has deferred these recoveries in accordance with the criteria set out in the AP Handbook.

Under such regulation, the variances are allowed to be deferred which would be recorded as revenue when incurred under Canadian GAAP for unregulated businesses. In the absence of rate regulation, the cost of power in 2012 would have been $262,182 lower (2011 - $4,368 lower).

The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. For the year ended December 31, 2012, settlement variance of $389,236 were disposed through rate adjustments (2011 - $NIL).

(e) Deferral account for OEB annual cost assessments:

The OEB has allowed the Corporation to defer the OEB annual cost assessments for the fiscal years starting after January 1, 2004. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

(f) Future income taxes:

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

As at December 31, 2012, the Corporation has recorded a future income tax asset of $253,852 (2011 - $227,762) and corresponding regulatory liability of $253,852 (2011 - $227,762).

8. Other Operating Revenue

	2012	2011
Investment income	$ 38,933	$ 60,746
Regulatory asset carrying charges	6,863	66,091
Late payment charges	27,525	23,669
Pole rentals	47,142	46,784
OPA grant revenue	122,890	38,484
Miscellaneous revenue	68,197	115,861
	$ 311,550	$ 351,635

9. Related Party Transactions

Fort Frances Power Corporation is owned by the Corporation of the Town of Fort Frances.

	2012	2011
Sales to the Corporation of the Town of Fort Frances	$ 653,794	$ 786,091
Purchased services from the Corporation of the Town of Fort Frances	$ 145,067	$ 124,164

The sales and purchases above were made in the normal course of business and recognized at the exchange amount which is equivalent to fair market value.

10. Credit Facilities

Fort Frances Power Corporation is party to a short-term credit facility with a Canadian chartered bank pursuant to which the Corporation could borrow up to $370,000 in the form of an operating loan. The amount drawn under the credit facility as at December 31, 2012, was $NIL.

11. Financial Guarantees

Participants in the wholesale market for electricity that is administered by the Independent Electricity Market Operator are required to satisfy prescribed prudential requirements.

The Corporation is party to an irrevocable standby letter of credit with a Canadian chartered bank. As at December 31, 2012, the credit amounts to $438,495 (2011 - $438,495). This letter of credit is secured by a general security agreement.

12. Pension Agreements

The Corporation makes contributions to the Ontario Municipal Employees' Retirement Fund (OMERS), a multi-employer plan, on behalf of nine members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. Employees and employers contribute jointly to the plan.

Because OMERS is a multi-employer pension plan, any pension plan surpluses or deficits are a joint responsibility of the Ontario municipal organizations and their employees. As a result, the Corporation does not recognize any share of the OMERS pension surplus or deficit. The amount contributed to OMERS for 2012 was $66,204 (2011 - $57,717) for current services. The OMERS Board rate was 8.3% to 12.8% depending on the income level for 2012 (2011 - 7.4% to 10.7% depending on the income level).

13. Capital Disclosures

The Corporation's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of the Fort Frances Power Corporation.
- ensure compliance with covenants related to its credit facilities.

As at December 31, 2012, the Corporation's definition of capital includes shareholder's equity. As at December 31, 2012, shareholder's equity amounts to $5,294,053 (2011 - $5,607,966). There have been no changes in the Corporation's approach to capital management during the year.

14. Risk Factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

The Corporation's activities provide for a variety of financial risks, particularly credit risk and liquidity risk.

Credit risk

Financial instruments are exposed to credit risk as a result of the risk of the counterparty defaulting on its obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risks based on the financial condition and short and long-term exposures to counterparties.

14. **Risk Factors** (continued)

The Corporation's credit risk associated with accounts receivable is primarily related to payments from Fort Frances Power Corporation customers. Fort Frances Power Corporation has approximately 4,000 customers, the majority of which are residential. Fort Frances Power Corporation collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2012, Fort Frances Power Corporation held security deposits in the amount of $49,291 (2011 - $55,887).

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations and deficit. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations and deficit.

At December 31, 2012, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. The Corporation attempts to minimize interest rate risk by issuing long-term fixed rate debt.

Under the Corporation's Revolving Credit Facility (Note 10), the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit).

Liquidity risk

The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

Hedging and derivatives risk

As at December 31, 2012, the Corporation has not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at December 31, 2012, the Corporation has limited exposure to the changing values of foreign currencies.

FFPC
FORT FRANCES POWER CORPORATION

Filing Number: EB-2013-0130
Filed: December 20, 2013

EXHIBIT TWO

RATE BASE

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Exhibit	**Tab**	Schedule	Appendix	Contents
	4			**Allowance for Working Capital**
		1		Overview and Calculation by Account
	5			**Treatment of Stranded Assets related to Smart Meter Deployment**
		1		Summary
		2		Cost of Power
Appendices			2A	FFPC Distribution System Plan for the Period 2014 to 2018

OVERVIEW:

The Fort Frances Power Corporation Distribution System

The Fort Frances Power Corporation (FFPC) owns and operates the electricity distribution system in its licensed service territory that is defined by the municipal boundaries of the Town of Fort Frances. FFPC serves a total of approximately 3,780 customers, in the Residential and General Service classes. FFPC also provides service to Street Lighting, Unmetered Scattered Load customers, microFIT and FIT customers.

FFPC's service territory is comprised of approximately 26 square kilometres of low density urban service territory. FFPC's customer density is 146 customers per square kilometer, and with respect to linear distribution plant it is 49.5 customers per primary circuit kilometre (km of Line). According to the definitions of "Urban" and "Rural" as set out in Appendix C of the DSC, FFPC's service territory is technically "Rural", as it is below the threshold of 60 customers per kilometer of line; however, FFPC treats it as "Urban", to adhere to the more stringent minimum inspection and maintenance requirements.

Power is supplied from the IESO controlled grid to FFPC's Greater than 50 kV Transformer Station "Fort Frances Municipal Transformer Station" (Fort Frances MTS), at a supply voltage of 115 kV. The transformer station is classified as a High Voltage (HV) asset, as its primary voltage of 115 kV is in the Transmission category (sometimes also referred to as Sub-Transmission). The station steps-down the incoming transmission supply to 7.2/12.47 kV, which is a voltage level that is suitable for distribution.

Some key system statistics follow:

Poles	1,776
Distribution Transformers	882
HV Transformer Stations	1
Km of Overhead Line	66
Km of Underground Line	8

For a detailed listing of assets refer to Section 5.3.2 "Overview of Assets Managed" of FFPC's 2014 to 2018 DS Plan.

FFPC's fixed asset continuity Schedule, as per Appendix 2-BA1, is located under Exhibit 2, Tab2, Schedule 1.

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application, is the average of the balances at the beginning and the end of the 2014 Test Year, plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses. The 13% working capital allowance is consistent with the Board's letter of April 12, 2012.

The net fixed assets include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. FFPC does not have non-distribution assets, and did not incur any non-distribution related expenses. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

This exhibit will compare historical data with the 2013 Bridge Year and 2014 Test Year. All comparisons will be made under CGAAP, as FFPC will not adopt MIFRS until January 1, 2015, as indicated in Exhibit 1, Tab 9, Schedule 9. Please note; however, that Pursuant to the Board letter July 17, 2012, FFPC has applied changes to the depreciation expense and capitalization policies effective January 1, 2013, consistent with the Board's regulatory accounting policy direction in that letter.

FFPC has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and 2014 Test Year in Table 2.1.1(a) below. FFPC has calculated its 2014 rate base as $4,649,092.

Table 2.1.1(a) – Summary of Rate Base

Description	2006 OEB Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Gross Fixed Assets	$8,987,154	$9,547,550	$9,645,591	$9,832,493	$10,110,278	$10,617,987	$10,629,133	$11,273,287	$11,530,209	$12,279,383
Accumulated Depreciation	$5,489,308	$6,179,199	$6,479,991	$6,852,035	$7,200,755	$7,543,754	$7,758,541	$8,022,923	$8,132,181	$8,339,638
Net Book Value	$3,497,846	$3,368,351	$3,165,600	$2,980,458	$2,909,523	$3,074,233	$2,870,592	$3,250,363	$3,398,027	$3,939,744
Average Net Book Value	$3,497,846	$3,393,105	$3,266,975	$3,073,029	$2,944,991	$2,991,878	$2,972,412	$3,060,478	$3,324,195	$3,668,886
Working Capital	$6,418,320	$6,944,887	$7,340,034	$7,171,248	$7,639,514	$7,060,565	$7,502,303	$8,902,297	$8,295,081	$8,650,546
Working Capital Allowance	$962,748	$1,041,733	$1,101,005	$1,075,687	$1,145,927	$1,059,085	$1,125,346	$1,335,345	$1,078,361	$1,124,571
Rate Base	**$4,460,594**	**$4,434,837**	**$4,367,981**	**$4,148,716**	**$4,090,916**	**$4,050,961**	**$4,097,757**	**$4,395,821**	**$4,402,553**	**$4,793,453**
OEB Prescribed Cap Allowance	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*13%*	*13%*

Table 2.1.1(b) below is a summary of FFPC's cost of power and controllable expenses used in calculating working capital for the period 2006 Actual to 2012 Actual, as well as 2006 Board Approved and 2013 Bridge Year and 2014 Test Year under CGAAP.

The changes in working capital are primarily due to the annual changes in cost of power and increases in OM&A expenses. The working capital allowance in the years 2006 OEB Approved, 2006, 2007, 2008, 2009, 2010, 2011, and 2012 Actuals are based on 15% cost of power and controllable expenses in accordance with the Filing Requirements. The working capital allowance in the years 2013 and 2014 are based on 13% cost of power and controllable expenses as set out in the Board's letter of April 12, 2012. For the 2014 Test Year, FFPC's Total Working Capital Expenses are projected to be $8,650,546 and with the prescribed allowance of 13% FFPC's corresponding Working Capital amount is $1,124,571.

Table 2.1.1(b) – Summary of Working Capital Calculation

Description	2006 OEB Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$142,165	$154,931	$167,586	$161,730	$194,356	$192,399	$195,697	$213,851	$209,500	$371,000
Maintenance	$106,651	$92,874	$113,833	$142,860	$130,396	$183,394	$169,076	$377,219	$213,000	$304,000
Billing and Collecting	$144,547	$237,343	$235,870	$254,460	$266,345	$265,204	$213,984	$255,946	$235,500	$268,000
Community Relations	$4,712	$62,599	$35,457	$21,187	$14,905	$8,805	$6,024	$5,978	$4,750	$37,150
Administrative and General	$603,271	$577,417	$612,906	$686,964	$710,557	$675,883	$717,211	$751,977	$750,500	$664,500
Taxes Other Than Income Taxes	$0	$14,525	$14,652	$14,638	$14,092	$12,775	$12,484	$12,264	$13,000	$13,000
Total Eligible Distribution Expenses	**$1,001,346**	**$1,139,689**	**$1,180,304**	**$1,281,839**	**$1,330,651**	**$1,338,460**	**$1,314,476**	**$1,617,235**	**$1,426,250**	**$1,657,650**
Power Supply Expenses	$5,416,974	$5,805,198	$6,159,730	$5,889,409	$6,308,863	$5,722,105	$6,187,827	$7,285,062	$6,868,831	$6,992,896
Total Working Capital Expenses	**$6,418,320**	**$6,944,887**	**$7,340,034**	**$7,171,248**	**$7,639,514**	**$7,060,565**	**$7,502,303**	**$8,902,297**	**$8,295,081**	**$8,650,546**
OEB Prescribed % Working Capital Allowance	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*13%*	*13%*
Working Capital Allowance	**$962,748**	**$1,041,733**	**$1,101,005**	**$1,075,687**	**$1,145,927**	**$1,059,085**	**$1,125,346**	**$1,335,345**	**$1,078,361**	**$1,124,571**

Rate Base Variance Analysis

Tables 2.1.2, 2.1.3, 2.1.4, 2.1.5, 2.1.6, 2.1.7, 2.1.8, 2.1.9, 2.1.10 below set out FFPC's year over year rate base variances for:

- 2006 OEB Approved to 2006 Actual
- 2006 Actual to 2007 Actual
- 2007 Actual to 2008 Actual
- 2008 Actual to 2009 Actual
- 2009 Actual to 2010 Actual
- 2010 Actual to 2011 Actual
- 2011 Actual to 2012 Actual
- 2012 Actual to 2013 Bridge, and
- 2013 Bridge to 2014 Test

Below each table FFPC offers comments in regards to relevant variances exceeding the threshold of $50,000, as outlined in the materiality section of this application.

2006 OEB Approved vs 2006 Actual:

Table 2.1.2: 2006 OEB Approved Rate Base vs. 2006 Actual

Description	2006 OEB Approved	2006 Actuals	Variance
Gross Fixed Assets	$ 8,987,154	$ 9,547,550	$ 560,395
Accumulated Depreciation	$ 5,489,308	$ 6,179,199	$ 689,891
Net Book Value	$ 3,497,846	$ 3,368,351	$ (129,496)
Average Net Book Value	$ 3,497,846	$ 3,393,105	$ (104,741)
Working Capital	$ 6,418,320	$ 6,944,887	$ 526,567
Working Capital Allowance	$ 962,748	$ 1,041,733	$ 78,985
Rate Base	**$ 4,460,594**	**$ 4,434,837**	**$ (25,757)**

Please note that 2006 Board approved amounts are based on 2004 historical amounts, which is causing the large variance between 2006 actual and 2006 Board comparisons, as there is a two year timing difference in the data sets. As such, the resulting variances are:

- Gross Fixed Assets: $ 560,395
- Accumulated Depreciation: $ 689,891
- Net Book Value: $ (129,496)
- Average Net Book Value: $ (104,741)
- Working Capital: $ 526,567
- Working Capital Allowance: $ 78,985
- Rate Base: $ (25,757)

2006 Actual vs 2007 Actual:

Table 2.1.3: 2006 Actual vs. 2007 Actual

Description	2006 Actuals	2007 Actuals	Variance
Gross Fixed Assets	$ 9,547,550	$ 9,645,591	$ 98,042
Accumulated Depreciation	$ 6,179,199	$ 6,479,991	$ 300,792
Net Book Value	$ 3,368,351	$ 3,165,600	$ (202,750)
Average Net Book Value	$ 3,393,105	$ 3,266,975	$ (126,129)
Working Capital	$ 6,944,887	$ 7,340,034	$ 395,148
Working Capital Allowance	$ 1,041,733	$ 1,101,005	$ 59,272
Rate Base	**$ 4,434,837**	**$ 4,367,981**	**$ (66,857)**

- Gross Fixed Assets: $ 98,042
  - Capital additions of $193,605 less disposals of $95,563, as per Table 2.2.2: Fixed Asset Continuity Schedule 2007 (summary provided below). Significant additions include; $73,722 to Poles, Towers & Fixtures; $40,008 to Line Transformers; and $38,368 to Overhead Conductor and Devices. Significant disposals include a line truck for $90,813 under Transportation Equipment.

Asset Addition and Disposal Summary Account	2007
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 2,090
Poles, Towers & Fixtures	$ 73,722
Overhead Conductors & Devices	$ 38,368
Underground Conductors & Devices	$ 9,200
Line Transformers	$ 40,008
Meters	$ 6,690
Buildings & Fixtures	$ 16,874
Office Furniture & Equipment (10 years)	$ 657
Computer Equipment - Hardware	$ 2,055
Transportation Equipment	$ 1,550
Tools, Shop & Garage Equipment	$ 2,391
Sub-Total	$ 193,605
Description	**Disposals**
Distribution Station Equipment <50 kV	$ 4,750
Transportation Equipment	$ 90,813
Sub-Total	$ 95,563
Gross Fixed Assets (Additions - Disposals)	$ 98,042

- Accumulated Depreciation: $ 300,792
  - Additions to depreciation of assets of $391,605 less disposals of $90,813, as shown in Table 2.2.2: Fixed Asset Continuity Schedule - 2007 (summary provided below). Significant additions to depreciation include; $209,720 to Poles, Towers & Fixtures; $44,897 to Line Transformers and $67,081 to Transportation Equipment. Significant disposals include $90,813 for a line truck.

Amortization Additions and Disposals Account	2007
Description	**Additions**
Buildings	$ 9,235
Distribution Station Equipment <50 kV	$ 25,756
Poles, Towers & Fixtures	$ 209,720
Underground Conductors & Devices	$ 2,181
Line Transformers	$ 44,897
Meters	$ 14,023
Buildings & Fixtures	$ 727
Leasehold Improvements	$ 2,101
Office Furniture & Equipment (10 years)	$ 3,240
Computer Equipment - Hardware	$ 5,807
Transportation Equipment	$ 67,081
Tools, Shop & Garage Equipment	$ 6,837
Sub-Total	$ 391,605
Description	**Disposals**
Transportation Equipment	$ 90,813
Sub-Total	$ 90,813
Gross Fixed Assets (Additions - Disposals)	$ 300,792

- Net Book Value: $ (202,750)
  - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ (126,129)
  - *Average of the two variances: 1) NBV Variance 2006 Actual vs 2007 Actual and 2) 2005 Actual and 2006 Actual.*
- Working Capital: $ 395,148

- Variance mainly due to the 2007 cost of power being $354,532 more than the 2006 cost of power.

- Working Capital Allowance: $ 59,272
  - *Result of applying 15% to Working Capital variance explained above.*
- Rate Base: $ (66,857)
  - *Sum of average net book value and working capital variances explained above.*

2007 Actual vs 2008 Actual:

Table 2.1.4: 2007 Actual vs. 2008 Actual

Description	2007 Actuals	2008 Actuals	Variance
Gross Fixed Assets	$ 9,645,591	$ 9,832,493	$ 186,902
Accumulated Depreciation	$ 6,479,991	$ 6,852,035	$ 372,044
Net Book Value	$ 3,165,600	$ 2,980,458	$ (185,142)
Average Net Book Value	$ 3,266,975	$ 3,073,029	$ (193,946)
Working Capital	$ 7,340,034	$ 7,171,248	$ (168,787)
Working Capital Allowance	$ 1,101,005	$ 1,075,687	$ (25,318)
Rate Base	**$ 4,367,981**	**$ 4,148,716**	**$ (219,265)**

- Gross Fixed Assets: $ 186,902
  - Capital additions of $186,902 less disposals of $0, as per Table 2.2.3: Fixed Asset Continuity Schedule 2008 (summary provided below). Significant additions include $108,667 to Poles, Towers & Fixtures, and there were no significant disposals.

Asset Addition and Disposal Summary Account	2008
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 15,540
Distribution Station Equipment <50 kV	$ 10,104
Poles, Towers & Fixtures	$ 108,677
Overhead Conductors & Devices	$ 3,645
Underground Conductors & Devices	$ 13,247
Line Transformers	$ 17,158
Meters	$ 1,299
Office Furniture & Equipment (10 years)	$ 12,933
Computer Equipment - Hardware	$ 1,638
Tools, Shop & Garage Equipment	$ 2,661
Sub-Total	$ 186,902
Description	**Disposals**
Sub-Total	$ -
Gross Fixed Assets (Additions - Disposals)	$ 186,902

- Accumulated Depreciation: $ 372,044
  - Additions to depreciation of assets of $372,044 less disposals of $0, as shown in Table 2.2.3: Fixed Asset Continuity Schedule - 2008 (Summary provided below). Significant additions include; $191,193 to Poles, Towers & Fixtures; $45,583 to Line Transformers; and $60,798 to Transportation Equipments. There were no disposals recorded in 2008.

Amortization Additions and Disposals Account	2008
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 956
Buildings	$ 9,234
Distribution Station Equipment <50 kV	$ 26,009
Poles, Towers & Fixtures	$ 191,193
Underground Conductors & Devices	$ 2,711
Line Transformers	$ 45,583
Meters	$ 14,075
Buildings & Fixtures	$ 727
Leasehold Improvements	$ 2,101
Office Furniture & Equipment (10 years)	$ 4,532
Computer Equipment - Hardware	$ 7,128
Transportation Equipment	$ 60,798
Tools, Shop & Garage Equipment	$ 6,997
Sub-Total	$ 372,044
Description	**Disposals**
Sub-Total	$ -
Gross Fixed Assets (Additions - Disposals)	$ 372,044

- Net Book Value: $ (185,142)
  - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ (193,946)
  - Average of the two variances: 1) NBV Variance 2007 Actual vs 2008 Actual and 2) 2006 Actual and 2007 Actual.
- Working Capital: $ (168,787)
  - Variance mainly due to the 2008 cost of power being $270,321 less than the 2007 cost of power, as well as eligible OM&A expenses increasing by

$101,549 in 2008, due largely to the hiring of a Powerline technician apprentice.

- Working Capital Allowance: $ (25,318)
  - *Result of applying 15% to Working Capital variance explained above.*
- Rate Base: $ (219,265)
  - Sum of average net book value and working capital variances explained above.

2008 Actual vs 2009 Actual:

Table 2.1.5: 2008 Actual vs. 2009 Actual

Description	2008 Actuals	2009 Actuals	Variance
Gross Fixed Assets	$ 9,832,493	$ 10,110,278	$ 277,785
Accumulated Depreciation	$ 6,852,035	$ 7,200,755	$ 348,721
Net Book Value	$ 2,980,458	$ 2,909,523	$ (70,936)
Average Net Book Value	$ 3,073,029	$ 2,944,991	$ (128,039)
Working Capital	$ 7,171,248	$ 7,639,514	$ 468,266
Working Capital Allowance	$ 1,075,687	$ 1,145,927	$ 70,240
Rate Base	**$ 4,148,716**	**$ 4,090,916**	**$ (57,800)**

- Gross Fixed Assets: $ 277,785
  - Capital additions of $277,785 less disposals of $0, as per Table 2.2.4: Fixed Asset Continuity Schedule 2009 (Summary provided below). Significant additions include; $103,477 to Poles, Towers & Fixtures; and $109,440 to Buildings and Fixture, for FFPC's Operational Centre Expansion project. There were no significant disposals.

Asset Addition and Disposal Summary Account	2009
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 5,230
Buildings	$ 232
Distribution Station Equipment <50 kV	$ 477
Poles, Towers & Fixtures	$ 103,477
Overhead Conductors & Devices	$ 5,062
Underground Conductors & Devices	$ 6,521
Line Transformers	$ 41,351
Meters	$ 1,276
Buildings & Fixtures	$ 109,440
Leasehold Improvements	$ 149
Office Furniture & Equipment (10 years)	$ 1,188
Computer Equipment - Hardware	$ 1,312
Tools, Shop & Garage Equipment	$ 2,070
Sub-Total	$ 277,785
Description	**Disposals**
Sub-Total	$ -
Gross Fixed Assets (Additions - Disposals)	$ 277,785

- Accumulated Depreciation: $ 348,721
  - Additions to depreciation of assets of $348,721 less disposals of $0, as shown in Table 2.2.4: Fixed Asset Continuity Schedule - 2009 (Summary provided below). Significant additions include $176,098 to Poles, Towers & Fixtures; $46,826 to Line Transformers and $47,418 to Transportation Equipment. There were no disposals recorded in 2009.

Amortization Additions and Disposals Account	2009
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 8,296
Buildings	$ 13,621
Distribution Station Equipment <50 kV	$ 26,026
Poles, Towers & Fixtures	$ 176,098
Underground Conductors & Devices	$ 2,972
Line Transformers	$ 46,826
Meters	$ 14,126
Buildings & Fixtures	$ 726
Leasehold Improvements	$ 888
Office Furniture & Equipment (10 years)	$ 4,652
Transportation Equipment	$ 47,418
Tools, Shop & Garage Equipment	$ 7,073
Sub-Total	$ 348,721
Description	**Disposals**
Sub-Total	$ -
Gross Fixed Assets (Additions - Disposals)	$ 348,721

- Net Book Value: $ (70,936)
  - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ (128,039)
  - Average of the two variances: 1) NBV Variance 2008 Actual vs 2009 Actual and 2) 2007 Actual and 2008 Actual.
- Working Capital: $ 468,266
  - Variance mainly due to the 2009 cost of power being $419,454 higher than the 2008 cost of power.
- Working Capital Allowance: $ 70,240

- *Result of applying 15% to Working Capital variance explained above*

- Rate Base: $ (57,800)
  - Sum of average net book value and working capital variances explained above.

2009 Actual vs 2010 Actual:

Table 2.1.6: 2009 Actual vs. 2010 Actual

Description	2009 Actuals	2010 Actuals	Variance
Gross Fixed Assets	$ 10,110,278	$ 10,617,987	$ 507,709
Accumulated Depreciation	$ 7,200,755	$ 7,543,754	$ 342,999
Net Book Value	$ 2,909,523	$ 3,074,233	$ 164,710
Average Net Book Value	$ 2,944,991	$ 2,991,878	$ 46,887
Working Capital	$ 7,639,514	$ 7,060,565	$ (578,949)
Working Capital Allowance	$ 1,145,927	$ 1,059,085	$ (86,842)
Rate Base	**$ 4,090,916**	**$ 4,050,961**	**$ (39,956)**

- Gross Fixed Assets: $ 507,709
  - Capital additions of $523,048 less disposals of $15,339, as per Table 2.2.5: Fixed Asset Continuity Schedule 2010 (Summary provided below). Significant additions include; $154,615 to Poles, Towers & Fixtures; $75,466 to Leasehold Improvements, for the installation of an emergency backup generator to power FFPC's Main Office Building; and $245,900 to Transportation Equipment, for the purchase of a Digger Derrick Truck. Significant disposals include end of life transformers, in the amount of $15,339.

Asset Addition and Disposal Summary Account	2010
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 2,454
Buildings	$ 1,480
Distribution Station Equipment <50 kV	$ 4,319
Poles, Towers & Fixtures	$ 154,615
Overhead Conductors & Devices	$ 503
Underground Conductors & Devices	$ 11,305
Line Transformers	$ 289
Buildings & Fixtures	$ 13,592
Leasehold Improvements	$ 75,466
Office Furniture & Equipment (10 years)	$ 1,799
Computer Equipment - Hardware	$ 8,839
Transportation Equipment	$ 245,900
Tools, Shop & Garage Equipment	$ 2,487
Sub-Total	$ 523,048
Description	**Disposals**
Line Transformers	$ 15,339
Sub-Total	$ 15,339
Gross Fixed Assets (Additions - Disposals)	$ 507,709

- Accumulated Depreciation: $ 342,999
  - Depreciation of assets less disposals as shown in Table 2.2.5: Fixed Asset Continuity Schedule - 2010 (Summary provided below). Significant additions include $182,303 to Poles, Towers & Fixtures; $45,150 to Line Transformers and $60,677 to Transportation Equipment.

Amortization Additions and Disposals Account	2010
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 8,381
Buildings	$ 14,198
Distribution Station Equipment <50 kV	$ 26,133
Poles, Towers & Fixtures	$ 182,303
Underground Conductors & Devices	$ 3,425
Line Transformers	$ 45,150
Meters	$ 2,844
Buildings & Fixtures	$ 218
Leasehold Improvements	$ 2,545
Office Furniture & Equipment (10 years)	$ 4,092
Transportation Equipment	$ 60,677
Tools, Shop & Garage Equipment	$ 7,152
Sub-Total	$ 357,118
Description	**Disposals**
Line Transformers	$ 14,119
Sub-Total	$ 14,119
Gross Fixed Assets (Additions - Disposals)	$ 342,999

- Net Book Value: $ 164,710
  - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ 46,887
  - Average of the two variances: 1) NBV Variance 2009 Actual vs 2010 Actual and 2) 2008 Actual and 2009 Actual.
- Working Capital: $ (578,949)
  - Variance mainly due to the 2010 cost of power being $586,758 lower than the 2009 cost of power.
- Working Capital Allowance: $ (86,842)

- *Result of applying 15% to Working Capital variance explained above*

- Rate Base: $ (39,956)
  - Sum of average net book value and working capital variances explained above.

2010 Actual vs 2011 Actual:

Table 2.1.7: 2010 Actual vs. 2011 Actual

Description	2010 Actuals	2011 Actuals	Variance
Gross Fixed Assets	$ 10,617,987	$ 10,629,133	$ 11,146
Accumulated Depreciation	$ 7,543,754	$ 7,758,541	$ 214,787
Net Book Value	$ 3,074,233	$ 2,870,592	$ (203,641)
Average Net Book Value	$ 2,991,878	$ 2,972,412	$ (19,466)
Working Capital	$ 7,060,565	$ 7,502,303	$ 441,739
Working Capital Allowance	$ 1,059,085	$ 1,125,346	$ 66,261
Rate Base	**$ 4,050,961**	**$ 4,097,757**	**$ 46,796**

- Gross Fixed Assets: $ 11,146
  - Capital additions of $145,321 less disposals of $134,175, as per Table 2.2.6: Fixed Asset Continuity Schedule 2011 (Summary provided below). Significant additions include $124,298 to Poles, Towers & Fixtures. FFPC also disposed of a Digger Derrick truck, resulting in $118,846 being recorded to Transportation Equipment Disposals.

Asset Addition and Disposal Summary Account	2011
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 875
Buildings	$ 3,756
Storage Battery Equipment	$ 696
Poles, Towers & Fixtures	$ 124,298
Underground Conductors & Devices	$ 6,511
Line Transformers	$ 2,609
Buildings & Fixtures	$ 3,728
Computer Equipment - Hardware	$ 2,268
Tools, Shop & Garage Equipment	$ 580
Sub-Total	$ 145,321
Description	**Disposals**
Line Transformers	$ 15,329
Transportation Equipment	$ 118,846
Sub-Total	$ 134,175
Gross Fixed Assets (Additions - Disposals)	$ 11,146

- Accumulated Depreciation: $ 214,787
  - Additions to depreciation of assets of $333,633 less disposals of $118,846 as shown in Table 2.2.6: Fixed Asset Continuity Schedule - 2011 (Summary provided below). Significant additions include $187,275 to Poles, Towers & Fixtures; $37,856 to Line Transformers and $42,176 to Transportation Equipment. Significant disposals include $118,846 to Transportation Equipment to reflect the disposal of FFPC's end of life Digger Derrick Truck.

Amortization Additions and Disposals Account	2011
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 3,417
Buildings	$ 14,497
Distribution Station Equipment <50 kV	$ 26,133
Poles, Towers & Fixtures	$ 187,275
Underground Conductors & Devices	$ 3,685
Line Transformers	$ 37,856
Buildings & Fixtures	$ 206
Leasehold Improvements	$ 2,545
Office Furniture & Equipment (10 years)	$ 3,792
Computer Equipment - Hardware	$ 5,127
Transportation Equipment	$ 42,176
Tools, Shop & Garage Equipment	$ 6,924
Sub-Total	$ 333,633
Description	**Disposals**
Transportation Equipment	$ 118,846
Sub-Total	$ 118,846
Gross Fixed Assets (Additions - Disposals)	$ 214,787

- Net Book Value: $ (203,641)
  - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ (19,466)
  - Average of the two variances: 1) NBV Variance 2010 Actual vs 2011 Actual and 2) 2009 Actual and 2010 Actual.
- Working Capital: $ 441,739
  - Variance mainly due to the 2011 cost of power being $465,722 higher than the 2010 cost of power.

- Working Capital Allowance: $ 66,261
  - *Result of applying 15% to Working Capital variance explained above*
- Rate Base: $ 46,796
  - Sum of average net book value and working capital variances explained above.

2011 Actual vs 2012 Actual:

Table 2.1.8: 2011 Actual vs. 2012 Actual

Description	2011 Actuals	2012 Actuals	Variance
Gross Fixed Assets	$ 10,629,133	$ 11,273,287	$ 644,154
Accumulated Depreciation	$ 7,758,541	$ 8,022,923	$ 264,382
Net Book Value	$ 2,870,592	$ 3,250,363	$ 379,772
Average Net Book Value	$ 2,972,412	$ 3,060,478	$ 88,065
Working Capital	$ 7,502,303	$ 8,902,297	$ 1,399,993
Working Capital Allowance	$ 1,125,346	$ 1,335,345	$ 209,999
Rate Base	**$ 4,097,757**	**$ 4,395,821**	**$ 298,064**

- Gross Fixed Assets: $ 644,154
  - Capital additions of $194,602, $841,418 of Smart Metering asset additions (from disposition of variance accounts), less disposals of $391,866, as per Table 2.2.7: Fixed Asset Continuity Schedule 2012 (Summary provided below). Significant additions include; $841,418 for the inclusion of Smart Meters in FFPC's asset base; and $157,180 to Poles, Towers & Fixtures. In 2012, FFPC also formally disposed of its traditional metering assets due to their replacement with Smart Meters and as such, $391,866 was recorded to Meters Disposal.

Asset Addition and Disposal Summary Account	2012
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 760
Poles, Towers & Fixtures	$ 157,180
Underground Conductors & Devices	$ 8,000
Line Transformers	$ 13,634
Meters	$ -
Meters (Smart Meters)	$ 841,418
Buildings & Fixtures	$ 10,835
Computer Equipment - Hardware	$ 1,910
Tools, Shop & Garage Equipment	$ 2,283
Sub-Total	$ 1,036,020
Description	**Disposals**
Meters	$ 391,866
Sub-Total	$ 391,866
Gross Fixed Assets (Additions - Disposals)	$ 644,154

- Accumulated Depreciation: $ 264,382
  - Additions to depreciation of assets of $564,032, less disposals of $299,649, as shown in Table 2.2.7: Fixed Asset Continuity Schedule - 2012. Significant additions include; $176,581 to Poles, Towers & Fixtures; $209,763 to Meters (Smart Meters); $30,987 to Line Transformers; and $42,176 to Transportation Equipment. Significant disposals include $299,649 to Meters, reflecting the disposal of conventional metering equipment utilized prior to the acquisition of Smart Meters.

Amortization Additions and Disposals Account	**2012**
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 3,266
Buildings	$ 14,633
Transformer Station Equipment >50 kV	$ 26,133
Poles, Towers & Fixtures	$ 176,581
Underground Conductors & Devices	$ 4,005
Line Transformers	$ 30,987
Meters	$ 38,356
Meters (Smart Meters)	$ 209,763
Buildings & Fixtures	$ 74
Leasehold Improvements	$ 2,545
Office Furniture & Equipment (10 years)	$ 3,680
Computer Equipment - Hardware	$ 4,899
Transportation Equipment	$ 42,176
Tools, Shop & Garage Equipment	$ 6,933
Sub-Total	$ 564,032
Description	**Disposals**
Meters	$ 299,649
Sub-Total	$ 299,649
Gross Fixed Assets (Additions - Disposals)	$ 264,382

- Net Book Value: $ 379,772
  - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ 88,065
  - Average of the two variances: 1) NBV Variance 2011 Actual vs 2012 Actual and 2) 2010 Actual and 2011 Actual.

- Working Capital: $ 1,399,993
  - Variance mainly due to the 2012 cost of power being $1,097,235 higher than the 2011 cost of power, as well as to the disposition of Smart Meter Variance accounts resulting in the recognition of $187,044 in increased OM&A expenses in 2012.
- Working Capital Allowance: $ 209,999
  - *Result of applying 15% to Working Capital variance explained above*
- Rate Base: $ 298,064
  - Sum of average net book value and working capital variances explained above.

2012 Actual vs 2013 Bridge:

Table 2.1.9: 2012 Actual vs. 2013 Bridge

Description	2012 Actuals	2013 Bridge Year	Variance
Gross Fixed Assets	$ 11,273,287	$ 11,530,209	$ 256,922
Accumulated Depreciation	$ 8,022,923	$ 8,132,181	$ 109,258
Net Book Value	$ 3,250,363	$ 3,398,027	$ 147,664
Average Net Book Value	$ 3,060,478	$ 3,324,195	$ 263,718
Working Capital	$ 8,902,297	$ 8,295,081	$ (607,216)
Working Capital Allowance	$ 1,335,345	$ 1,078,361	$ (256,984)
Rate Base	**$ 4,395,821**	**$ 4,402,553**	**$ 6,732**

- Gross Fixed Assets: $ 256,922
  - Capital additions of $363,960, less disposals of $107,038, as per Table 2.2.8: Fixed Asset Continuity Schedule 2013 - Bridge Year (Summary provided below). Significant additions include; $121,891 to Poles, Towers & Fixtures; and $120,000 to Transportation Equipment, for the replacement of a Single Bucket Truck. Material disposal include $107,038 recorded to Transportation Equipment, from the replacement of the Single Bucket Truck.

Asset Addition and Disposal Summary Account	2013
Description	Additions
Computer Software (Formally known as Account 1925)	$ 27,500
Buildings	$ 2,000
Transformer Station Equipment >50 kV	$ 2,000
Storage Battery Equipment	$ 2,000
Poles, Towers & Fixtures	$ 121,891
Overhead Conductors & Devices	$ 14,500
Underground Conductors & Devices	$ 8,769
Line Transformers	$ 15,000
Services (Overhead & Underground)	$ 2,000
Buildings & Fixtures	$ 24,000
Leasehold Improvements	$ 1,500
Office Furniture & Equipment (10 years)	$ 3,000
Computer Equipment - Hardware	$ 5,900
Transportation Equipment	$ 120,000
Tools, Shop & Garage Equipment	$ 11,500
Measurement & Testing Equipment	$ 1,500
Communications Equipment	$ 900
Sub-Total	$ 363,960

Description	Disposals
Transportation Equipment	$ 107,038
Sub-Total	$ 107,038
Gross Fixed Assets (Additions - Disposals)	$ 256,922

- Accumulated Depreciation: $ 109,258
  - Additions to depreciation of assets of $216,296 less disposals of $107,038, as shown in Table 2.2.9: Fixed Asset Continuity Schedule - 2013 Bridge Year (Summary provided below). Significant additions include; $37,172 to Poles, Towers & Fixtures; and $63,166 to Meters (Smart Meters). Significant disposals include $107,038 recorded to Transportation Equipment, for the disposal of a Single Bucket Truck.

Amortization Additions and Disposals Account	2013
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 10,115
Buildings	$ 3,483
Transformer Station Equipment >50 kV	$ 6,618
Storage Battery Equipment	$ 1,728
Poles, Towers & Fixtures	$ 37,172
Overhead Conductors & Devices	$ 15,648
Underground Conduit	$ 55
Underground Conductors & Devices	$ 5,740
Line Transformers	$ 15,627
Services (Overhead & Underground)	$ 1,078
Meters (Smart Meters)	$ 63,166
Buildings & Fixtures	$ 9,265
Leasehold Improvements	$ 4,605
Office Furniture & Equipment (10 years)	$ 2,570
Computer Equipment - Hardware	$ 2,026
Transportation Equipment	$ 29,858
Tools, Shop & Garage Equipment	$ 7,267
Measurement & Testing Equipment	$ 188
Communications Equipment	$ 90
Sub-Total	$ 216,296
Description	**Disposals**
Transportation Equipment	$ 107,038
Sub-Total	$ 107,038
Gross Fixed Assets (Additions - Disposals)	$ 109,258

- Net Book Value: $ 147,664
  - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ 263,718
  - Average of the two variances: 1) NBV Variance 2012 Actual vs 2013 Bridge and 2) 2011 Actual and 2012 Actual.
- Working Capital: $ (607,216)
  - Variance mainly due to the 2013 forecasted cost of power being $416,231 lower than the 2012 cost of power, as well as a reduction in OM&A expense as one-time Smart Meter expenses were recognized in 2012.
- Working Capital Allowance: $ (256,984)
  - *Result of applying 13% to Working Capital variance explained above*
- Rate Base: $ (6,732)
  - Sum of average net book value and working capital variances explained above.

2013 Bridge vs 2014 Test:

Table 2.1.10: 2013 Bridge vs. 2014 Test

Description	2013 Bridge Year	2014 Test Year	Variance
Gross Fixed Assets	$ 11,530,209	$ 12,279,383	$ 749,174
Accumulated Depreciation	$ 8,132,181	$ 8,339,638	$ 207,457
Net Book Value	$ 3,398,027	$ 3,939,744	$ 541,717
Average Net Book Value	$ 3,324,195	$ 3,668,886	$ 344,690
Working Capital	$ 8,295,081	$ 8,650,546	$ 355,465
Working Capital Allowance	$ 1,078,361	$ 1,124,571	$ 46,210
Rate Base	**$ 4,402,553**	**$ 4,793,453**	**$ 390,900**

- Gross Fixed Assets: $ 749,174
  - Capital additions of $770,316 less disposals of $21,142, as per Table 2.2.9: Fixed Asset Continuity Schedule - 2014 Test Year (Summary provided below). Significant additions include; $424,609 to Poles, Towers & Fixtures, due largely to planned feeder expansions to eliminate Long Term Load Transfers; $134,228 to Line Transformers; and $50,000 to Transportation Equipment, for the replacement of a Cable Reel & Tensioning Trailer.

Asset Addition and Disposal Summary Account	2014
Description	Additions
Computer Software (Formally known as Account 1925)	$ 4,000
Buildings	$ 5,000
Storage Battery Equipment	$ 2,000
Poles, Towers & Fixtures	$ 424,609
Overhead Conductors & Devices	$ 51,680
Underground Conduit	$ 27,000
Underground Conductors & Devices	$ 18,549
Line Transformers	$ 134,228
Services (Overhead & Underground)	$ 4,000
Meters (Smart Meters)	$ 5,750
Buildings & Fixtures	$ 7,500
Office Furniture & Equipment (10 years)	$ 6,500
Computer Equipment - Hardware	$ 15,500
Transportation Equipment	$ 50,000
Tools, Shop & Garage Equipment	$ 10,500
Measurement & Testing Equipment	$ 3,500
Sub-Total	$ 770,316

Description	Disposals
Transportation Equipment	$ 21,142
Sub-Total	$ 21,142
Gross Fixed Assets (Additions - Disposals)	$ 749,174

- Accumulated Depreciation: $ 207,457
  - Additions to depreciation of assets of $228,599 less disposals of $21,142, as shown in Table 2.2.9: Fixed Asset Continuity Schedule - 2013 Test Year (Summary provided below). Significant additions include; $41,890 to Poles, Towers & Fixtures; and $63,357 to Meters (Smart Meters). Significant disposals include $21,142 recorded to Transportation Equipment, for the disposal of a Cable Reel & Tensioning Trailer.

Amortization Additions and Disposals Account	2014
Description	**Additions**
Computer Software (Formally known as Account 1925)	$ 10,515
Buildings	$ 3,523
Transformer Station Equipment >50 kV	$ 6,618
Storage Battery Equipment	$ 1,794
Poles, Towers & Fixtures	$ 41,890
Overhead Conductors & Devices	$ 16,078
Underground Conduit	$ 280
Underground Conductors & Devices	$ 5,972
Line Transformers	$ 17,305
Services (Overhead & Underground)	$ 1,128
Meters (Smart Meters)	$ 63,357
Buildings & Fixtures	$ 9,359
Leasehold Improvements	$ 4,605
Office Furniture & Equipment (10 years)	$ 2,786
Computer Equipment - Hardware	$ 3,576
Transportation Equipment	$ 31,525
Tools, Shop & Garage Equipment	$ 7,792
Measurement & Testing Equipment	$ 406
Communications Equipment	$ 90
Sub-Total	$ 228,599
Description	**Disposals**
Transportation Equipment	$ 21,142
Sub-Total	$ 21,142
Gross Fixed Assets (Additions - Disposals)	$ 207,457

- Net Book Value: $ 541,717
    - Difference between Gross Fixed Assets and Accumulated Depreciation variances explained above.
- Average Net Book Value: $ 344,690
    - Average of the two variances: 1) NBV Variance 2013 Bridge vs 2014 Test and 2) 2012 Actual and 2013 Bridge.
- Working Capital: $ 355,465
    - Variance mainly due to the 2014 forecasted cost of power being $124,065 higher than the 2013 cost of power, as well as eligible OM&A expenses are projected to be $231,400 higher in 2014 than in 2013.
- Working Capital Allowance: $ 46,210
    - *Result of applying 13% to Working Capital variance explained above*
- Rate Base: $ 390,900
    - Sum of average net book value and working capital variances explained above.

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT and ACCUMULATED AMORTIZATION:

REGULATORY ACCOUNTING POLICY DIRECTION REGARDING CHANGES TO DEPRECIATION EXPENSE AND CAPITALIZATION POLICIES

As a rate-regulated entity, FFPC has elected to defer implementation of modified International Financial Reporting Standards (IFRS) until January 1, 2015. However, pursuant to the Board letter July 17, 2012, FFPC has applied changes to the depreciation expense and capitalization policies effective January 1, 2013. These changes are reflected in FFPC's 2013 Bridge Year and 2014 Test Year financial statements and results. Details of the amount of the changes are provided in Exhibit 9, Tab 3, Schedule 6.

Fixed Asset Continuity Statements

Tables 2.2.1, 2.2.2, 2.2.3, 2.2.4, 2.2.5, 2.2.6, 2.2.7, 2.2.8, 2.2.9 below provide details of the Fixed Asset Continuity Schedules for the years 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and 2014 Test Year.

Table 2.2.10 below provides details of Variances of Gross Assets year over from 2006 Actual through to 2014 Test Year.

Table 2.2.11 below provides details of Variances of Accumulated Amortization year over from 2006 Actual through to 2014 Test Year.

FFPC uses the following accounts and descriptions in the calculations of its net fixed assets:

1805 – Land: This account is used to record the cost of land held by FFPC, used in connection with distribution.

1806 - Land Rights: This account is used to record the cost of rights, interests, easements and privileges held by the LDC in land owned by others. FFPC currently does not have any balances recorded in this account.

1815 - Transformer Station Equipment - Normally Primary above 50 kV: FFPC owns and operates one transformer station. Historically, the transformer station was improperly classified as a Distribution Station - Normally Primary below 50 kV, when in actuality it is a Transformer Station - Normally Primary above 50 kV station, or in other words a "High Voltage" asset. As such, expenses are recorder under this account as of 2012. This account is used to record the installed cost of transforming and switching equipment of FFPC's transformer station "Fort Frances MTS". The purpose of the station is to step down the incoming transmission supply voltage from 115 kV, to the 7.2/12.47 distribution voltage. As FFPC only owns and operates one transformer station, it is not necessary to track and detail the age, cost location, and voltage characteristics of multiple stations.

1820 - Distribution Station Equipment – Normally Primary below 50 kV: As per the above, this account was used prior to 2012 to record the installed cost of transforming and switching equipment of FFPC's transformer station "Fort Frances MTS", a high voltage asset. In 2012, the balances recorded under this account were transferred to account 1815, and this account is no longer used as FFPC does not own or operate Distribution Stations Equipment.

1830 - Poles, Towers and Fixtures: This account is used to record the installed cost of poles, towers, and fixtures used for supporting overhead distribution conductors and

service wires in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. FFPC owns approximately 1,776 poles within its service territory.

1835 - Overhead Conductors and Devices: This account is used to record the installed cost of overhead conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. FFPC has approximately 66 kilometers of overhead line within its service territory.

1840 - Underground Conduit: This account is used to record the installed cost of underground conduit and tunnels used for housing distribution cables or wires in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1845 - Underground Conductors and Devices: This account is used to record the installed cost of underground conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1850 - Distribution Transformers: This account is used to record the installed cost of overhead and underground distribution line transformers and pole type and underground voltage regulators owned by the utility for use in transforming electricity to the voltage at which it is to be used by the customer in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1855 - Services: This account is used to record the installed cost of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system of the transformers, or manhole, or the top of the pole of the

distribution line to the point of connection with the customers' electrical panel, in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1860 - Meters: This account is used to record the installed cost of traditional meters or devices for use in measuring the electricity delivered to its users, including Smart Meters.

1908 - Buildings and Fixtures: This account includes the costs of buildings and fixtures used for utility purposes owned by FFPC.

1915 - Office Furniture & Equipment: This account contains the cost of general office furniture and equipment.

1920 - Computer Equipment -Hardware: This account includes costs of all computer hardware purchased. Hardware is inclusive of all physical equipment associated with input, processing, storage and output functions, also word processing equipment.

1925 - Computer Software: This account contains the installed costs of all computer software purchased or developed in house.

1930 – Transportation Equipment: This account contains the costs of all vehicles owned by FFPC, including automobiles, small trucks, truck chassis, special truck bodies, and other mobile equipment. The items in this account are considered unique and identifiable assets.

1935 – Stores Equipment: This account is used to record the cost of equipment used in FFPC's warehouse for shipping, receiving, handling and storage of materials and supplies. FFPC currently does not have any balances recorded in this account.

1940 – Tools, Shop and Garage Equipment: This account contains the cost of all tools and non-power equipment purchased by FFPC in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB.

1945 – Measurement and Testing Equipment: This account contains the cost of all measurement and testing equipment purchased by FFPC in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB.

1955 – Communications Equipment: This account includes amounts relating to telephone and wireless equipment for the general use in connection with utility operations.

1960 – Miscellaneous Equipment: This account is used to record amounts relating to equipment, apparatus, etc. used in the LDC operations which is not included in other accounts. FFPC currently does not have any balances recorded in this account.

1980 – System Supervisory Equipment: This account is used to record amounts relating to control equipment used for the purposes of remote operation and control of utility transformer stations and distribution equipment. FFPC currently does not have any balances recorded in this account.

1995 – Contributions and Grants: This account is used to record amounts relating to contribution or grants in cash, services or property from government or government

agencies, corporation, individuals and others who received in aid of construction or for acquisition of fixed assets (contributed capital.).

Table 2.2.1: Fixed Asset Continuity Schedule (CGAAP) - 2006

			Year	2006						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 2,905			$ 2,905				$ -	$ 2,905
1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
1805	Land	$ 100,000			$ 100,000				$ -	$ 100,000
1808	Buildings	$ 817,909			$ 817,909	$ 658,305	$ 8,559		$ 666,864	$ 151,045
1810	Leasehold Improvements				$ -				$ -	$ -
1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 1,047,561	$ 18,512		$ 1,066,073	$ 755,860	$ 25,875		$ 781,735	$ 284,338
1825	Storage Battery Equipment		$ 8,869		$ 8,869				$ -	$ 8,869
1830	Poles, Towers & Fixtures	$ 4,376,905	$ 70,755		$ 4,447,660	$ 2,657,165	$ 205,237		$ 2,862,402	$ 1,585,258
1835	Overhead Conductors & Devices	$ 312,669	$ 41,062		$ 353,731	$ 750			$ 750	$ 352,981
1840	Underground Conduit	$ 2,183			$ 2,183				$ -	$ 2,183
1845	Underground Conductors & Devices	$ 36,180	$ 6,975		$ 43,155	$ 5,371	$ 1,814		$ 7,185	$ 35,970
1850	Line Transformers	$ 1,105,368	$ 19,624		$ 1,124,992	$ 758,210	$ 43,009		$ 801,219	$ 323,773
1855	Services (Overhead & Underground)	$ 7,197			$ 7,197				$ -	$ 7,197
1860	Meters	$ 351,835	$ 30,766		$ 382,601	$ 202,470	$ 13,755		$ 216,225	$ 166,376
1860	Meters (Smart Meters)				$ -				$ -	$ -
1905	Land				$ -				$ -	$ -
1908	Buildings & Fixtures	$ 250,639			$ 250,639	$ 250,062	$ 727		$ 250,789	-$ 150
1910	Leasehold Improvements	$ 10,507			$ 10,507	$ 3,345	$ 2,102		$ 5,447	$ 5,060
1915	Office Furniture & Equipment (10 years)	$ 91,245	$ 9,586		$ 100,831	$ 76,416	$ 3,275		$ 79,691	$ 21,140
1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
1920	Computer Equipment - Hardware	$ 26,707	$ 2,322		$ 29,029	$ 14,630	$ 5,153		$ 19,783	$ 9,246
1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
1930	Transportation Equipment	$ 643,038	$ 90,569	-$ 75,000	$ 658,607	$ 397,318	$ 66,693	-$ 75,000	$ 389,011	$ 269,596
1935	Stores Equipment				$ -				$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 105,108	$ 35,554		$ 140,662	$ 90,195	$ 7,903		$ 98,098	$ 42,564
1945	Measurement & Testing Equipment				$ -				$ -	$ -
1950	Power Operated Equipment				$ -				$ -	$ -
1955	Communications Equipment				$ -				$ -	$ -
1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
1960	Miscellaneous Equipment				$ -				$ -	$ -
1970	Load Management Controls Customer Premises				$ -				$ -	$ -
1975	Load Management Controls Utility Premises				$ -				$ -	$ -
1980	System Supervisor Equipment				$ -				$ -	$ -
1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
1990	Other Tangible Property				$ -				$ -	$ -
1995	Contributions & Grants				$ -				$ -	$ -
1531	REG Capital Deferral Account				$ -				$ -	$ -
1565	CDM Expenditures				$ -				$ -	$ -
	Sub-Total	**$ 9,287,956**	**$ 334,594**	**-$ 75,000**	**$ 9,547,550**	**$ 5,870,097**	**$ 384,102**	**-$ 75,000**	**$ 6,179,199**	**$ 3,368,351**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	Total PP&E	**$ 9,287,956**	**$ 334,594**	**-$ 75,000**	**$ 9,547,550**	**$ 5,870,097**	**$ 384,102**	**-$ 75,000**	**$ 6,179,199**	**$ 3,368,351**

Table 2.2.2: Fixed Asset Continuity Schedule (CGAAP) - 2007

			Year	2007						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 2,905	$ 2,090		$ 4,995	$ -			$ -	$ 4,995
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 817,909			$ 817,909	$ 666,864	$ 9,235		$ 676,099	$ 141,810
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 1,066,073		$ 4,750	$ 1,061,323	$ 781,735	$ 25,756		$ 807,491	$ 253,832
1825	Storage Battery Equipment	$ 8,869			$ 8,869	$ -			$ -	$ 8,869
1830	Poles, Towers & Fixtures	$ 4,447,660	$ 73,722		$ 4,521,382	$ 2,862,402	$ 209,720		$ 3,072,122	$ 1,449,260
1835	Overhead Conductors & Devices	$ 353,731	$ 38,368		$ 392,099	$ 750			$ 750	$ 391,349
1840	Underground Conduit	$ 2,183			$ 2,183	$ -			$ -	$ 2,183
1845	Underground Conductors & Devices	$ 43,155	$ 9,200		$ 52,355	$ 7,185	$ 2,181		$ 9,366	$ 42,989
1850	Line Transformers	$ 1,124,992	$ 40,008		$ 1,165,000	$ 801,219	$ 44,897		$ 846,116	$ 318,884
1855	Services (Overhead & Underground)	$ 7,197			$ 7,197	$ -			$ -	$ 7,197
1860	Meters	$ 382,601	$ 6,690		$ 389,291	$ 216,225	$ 14,023		$ 230,248	$ 159,043
1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 250,639	$ 16,874		$ 267,513	$ 250,789	$ 727		$ 251,516	$ 15,997
1910	Leasehold Improvements	$ 10,507			$ 10,507	$ 5,447	$ 2,101		$ 7,548	$ 2,959
1915	Office Furniture & Equipment (10 years)	$ 100,831	$ 657		$ 101,488	$ 79,691	$ 3,240		$ 82,931	$ 18,557
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 29,029	$ 2,055		$ 31,084	$ 19,783	$ 5,807		$ 25,590	$ 5,494
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 658,607	$ 1,550	$ 90,813	$ 569,344	$ 389,011	$ 67,081	$ 90,813	$ 365,279	$ 204,065
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 140,662	$ 2,391		$ 143,053	$ 98,098	$ 6,837		$ 104,935	$ 38,118
1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ -			$ -	$ -			$ -	$ -
1565	CDM Expenditures	$ -			$ -	$ -			$ -	$ -
	Sub-Total	**$ 9,547,550**	**$ 193,605**	**$ 95,563**	**$ 9,645,591**	**$ 6,179,199**	**$ 391,605**	**$ 90,813**	**$ 6,479,991**	**$ 3,165,600**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -	$ -			$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -	$ -			$ -	$ -
	Total PP&E	**$ 9,547,550**	**$ 193,605**	**$ 95,563**	**$ 9,645,591**	**$ 6,179,199**	**$ 391,605**	**$ 90,813**	**$ 6,479,991**	**$ 3,165,600**

Table 2.2.3: Fixed Asset Continuity Schedule (CGAAP) - 2008

			Year	2008						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 4,995	$ 15,540		$ 20,535	$ -	$ 956		$ 956	$ 19,579
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 817,909			$ 817,909	$ 676,099	$ 9,234		$ 685,333	$ 132,576
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 1,061,323	$ 10,104		$ 1,071,427	$ 807,491	$ 26,009		$ 833,500	$ 237,927
1825	Storage Battery Equipment	$ 8,869			$ 8,869	$ -			$ -	$ 8,869
1830	Poles, Towers & Fixtures	$ 4,521,382	$ 108,677		$ 4,630,059	$ 3,072,122	$ 191,193		$ 3,263,315	$ 1,366,744
1835	Overhead Conductors & Devices	$ 392,099	$ 3,645		$ 395,744	$ 750			$ 750	$ 394,994
1840	Underground Conduit	$ 2,183			$ 2,183	$ -			$ -	$ 2,183
1845	Underground Conductors & Devices	$ 52,355	$ 13,247		$ 65,602	$ 9,366	$ 2,711		$ 12,077	$ 53,525
1850	Line Transformers	$ 1,165,000	$ 17,158		$ 1,182,158	$ 846,116	$ 45,583		$ 891,699	$ 290,459
1855	Services (Overhead & Underground)	$ 7,197			$ 7,197	$ -			$ -	$ 7,197
1860	Meters	$ 389,291	$ 1,299		$ 390,590	$ 230,248	$ 14,075		$ 244,323	$ 146,267
1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 267,513			$ 267,513	$ 251,516	$ 727		$ 252,243	$ 15,270
1910	Leasehold Improvements	$ 10,507			$ 10,507	$ 7,548	$ 2,101		$ 9,649	$ 858
1915	Office Furniture & Equipment (10 years)	$ 101,488	$ 12,933		$ 114,421	$ 82,931	$ 4,532		$ 87,463	$ 26,958
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 31,084	$ 1,638		$ 32,722	$ 25,590	$ 7,128		$ 32,718	$ 4
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 569,344			$ 569,344	$ 365,279	$ 60,798		$ 426,077	$ 143,267
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 143,053	$ 2,661		$ 145,714	$ 104,935	$ 6,997		$ 111,932	$ 33,782
1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ -			$ -	$ -			$ -	$ -
1565	CDM Expenditures	0			$ -	0			$ -	$ -
	Sub-Total	**$ 9,645,591**	**$ 186,902**	**$ -**	**$ 9,832,493**	**$ 6,479,991**	**$ 372,044**	**$ -**	**$ 6,852,035**	**$ 2,980,458**
	Less Socialized Renewable Energy Generation Investments (input as negative)	0			$ -	0			$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)	0			$ -	0			$ -	$ -
	Total PP&E	**$ 9,645,591**	**$ 186,902**	**$ -**	**$ 9,832,493**	**$ 6,479,991**	**$ 372,044**	**$ -**	**$ 6,852,035**	**$ 2,980,458**

Table 2.2.4: Fixed Asset Continuity Schedule (CGAAP)- 2009

			Year	2009						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 20,535	$ 5,230		$ 25,765	$ 956	$ 8,296		$ 9,252	$ 16,513
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 817,909	$ 232		$ 818,141	$ 685,333	$ 13,621		$ 698,954	$ 119,187
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 1,071,427	$ 477		$ 1,071,904	$ 833,500	$ 26,026		$ 859,526	$ 212,378
1825	Storage Battery Equipment	$ 8,869			$ 8,869	$ -			$ -	$ 8,869
1830	Poles, Towers & Fixtures	$ 4,630,059	$ 103,477		$ 4,733,536	$ 3,263,315	$ 176,098		$ 3,439,413	$ 1,294,123
1835	Overhead Conductors & Devices	$ 395,744	$ 5,062		$ 400,806	$ 750			$ 750	$ 400,056
1840	Underground Conduit	$ 2,183			$ 2,183	$ -			$ -	$ 2,183
1845	Underground Conductors & Devices	$ 65,602	$ 6,521		$ 72,123	$ 12,077	$ 2,972		$ 15,049	$ 57,074
1850	Line Transformers	$ 1,182,158	$ 41,351		$ 1,223,509	$ 891,699	$ 46,826		$ 938,525	$ 284,984
1855	Services (Overhead & Underground)	$ 7,197			$ 7,197	$ -			$ -	$ 7,197
1860	Meters	$ 390,590	$ 1,276		$ 391,866	$ 244,323	$ 14,126		$ 258,449	$ 133,417
1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 267,513	$ 109,440		$ 376,953	$ 252,243	$ 726		$ 252,969	$ 123,984
1910	Leasehold Improvements	$ 10,507	$ 149		$ 10,656	$ 9,649	$ 888		$ 10,537	$ 119
1915	Office Furniture & Equipment (10 years)	$ 114,421	$ 1,188		$ 115,609	$ 87,463	$ 4,652		$ 92,115	$ 23,494
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 32,722	$ 1,312		$ 34,034	$ 32,718			$ 32,718	$ 1,316
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 569,344			$ 569,344	$ 426,077	$ 47,418		$ 473,495	$ 95,849
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 145,714	$ 2,070		$ 147,784	$ 111,932	$ 7,073		$ 119,005	$ 28,779
1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ -			$ -	$ -			$ -	$ -
1565	CDM Expenditures	$ -			$ -	$ -			$ -	$ -
	Sub-Total	**$ 9,832,493**	**$ 277,785**	**$ -**	**$ 10,110,278**	**$ 6,852,035**	**$ 348,721**	**$ -**	**$ 7,200,755**	**$ 2,909,523**
	Less Socialized Renewable Energy Generation Investments (input as negative)	$ -			$ -	$ -			$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
	Total PP&E	**$ 9,832,493**	**$ 277,785**	**$ -**	**$ 10,110,278**	**$ 6,852,035**	**$ 348,721**	**$ -**	**$ 7,200,755**	**$ 2,909,523**

Table 2.2.5: Fixed Asset Continuity Schedule (CGAAP) - 2010

			Year	2010						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 25,765	$ 2,454		$ 28,219	$ 9,252	$ 8,381		$ 17,633	$ 10,586
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 818,141	$ 1,480		$ 819,621	$ 698,954	$ 14,198		$ 713,152	$ 106,469
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 1,071,904	$ 4,319		$ 1,076,223	$ 859,526	$ 26,133		$ 885,659	$ 190,564
1825	Storage Battery Equipment	$ 8,869			$ 8,869	$ -			$ -	$ 8,869
1830	Poles, Towers & Fixtures	$ 4,733,536	$ 154,615		$ 4,888,151	$ 3,439,413	$ 182,303		$ 3,621,716	$ 1,266,435
1835	Overhead Conductors & Devices	$ 400,806	$ 503		$ 401,309	$ 750			$ 750	$ 400,559
1840	Underground Conduit	$ 2,183			$ 2,183	$ -			$ -	$ 2,183
1845	Underground Conductors & Devices	$ 72,123	$ 11,305		$ 83,428	$ 15,049	$ 3,425		$ 18,474	$ 64,954
1850	Line Transformers	$ 1,223,509	$ 289	$ 15,339	$ 1,208,459	$ 938,525	$ 45,150	$ 14,119	$ 969,556	$ 238,903
1855	Services (Overhead & Underground)	$ 7,197			$ 7,197	$ -			$ -	$ 7,197
1860	Meters	$ 391,866			$ 391,866	$ 258,449	$ 2,844		$ 261,293	$ 130,573
1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 376,953	$ 13,592		$ 390,545	$ 252,969	$ 218		$ 253,187	$ 137,358
1910	Leasehold Improvements	$ 10,656	$ 75,466		$ 86,122	$ 10,537	$ 2,545		$ 13,082	$ 73,040
1915	Office Furniture & Equipment (10 years)	$ 115,609	$ 1,799		$ 117,407	$ 92,115	$ 4,092		$ 96,207	$ 21,201
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 34,034	$ 8,839		$ 42,873	$ 32,718			$ 32,718	$ 10,155
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 569,344	$ 245,900		$ 815,244	$ 473,495	$ 60,677		$ 534,172	$ 281,072
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 147,784	$ 2,487		$ 150,271	$ 119,005	$ 7,152		$ 126,157	$ 24,114
1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ -			$ -	$ -			$ -	$ -
1565	CDM Expenditures	$ -			$ -	$ -			$ -	$ -
	Sub-Total	**$ 10,110,278**	**$ 523,048**	**$ 15,339**	**$ 10,617,987**	**$ 7,200,755**	**$ 357,118**	**$ 14,119**	**$ 7,543,754**	**$ 3,074,233**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	Total PP&E	**$ 10,110,278**	**$ 523,048**	**$ 15,339**	**$ 10,617,987**	**$ 7,200,755**	**$ 357,118**	**$ 14,119**	**$ 7,543,754**	**$ 3,074,233**

Table 2.2.6: Fixed Asset Continuity Schedule (CGAAP) - 2011

			Year	2011						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 28,219	$ 875		$ 29,094	$ 17,633	$ 3,417		$ 21,050	$ 8,044
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 819,621	$ 3,756		$ 823,377	$ 713,152	$ 14,497		$ 727,649	$ 95,728
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 1,076,223			$ 1,076,223	$ 885,659	$ 26,133		$ 911,792	$ 164,431
1825	Storage Battery Equipment	$ 8,869	$ 696		$ 9,565	$ -			$ -	$ 9,565
1830	Poles, Towers & Fixtures	$ 4,888,151	$ 124,298		$ 5,012,449	$ 3,621,716	$ 187,275		$ 3,808,991	$ 1,203,458
1835	Overhead Conductors & Devices	$ 401,309			$ 401,309	$ 750			$ 750	$ 400,559
1840	Underground Conduit	$ 2,183			$ 2,183	$ -			$ -	$ 2,183
1845	Underground Conductors & Devices	$ 83,428	$ 6,511		$ 89,939	$ 18,474	$ 3,685		$ 22,159	$ 67,780
1850	Line Transformers	$ 1,208,459	$ 2,609	$ 15,329	$ 1,195,739	$ 969,556	$ 37,856		$ 1,007,412	$ 188,327
1855	Services (Overhead & Underground)	$ 7,197			$ 7,197	$ -			$ -	$ 7,197
1860	Meters	$ 391,866			$ 391,866	$ 261,293			$ 261,293	$ 130,573
1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 390,545	$ 3,728		$ 394,273	$ 253,187	$ 206		$ 253,393	$ 140,880
1910	Leasehold Improvements	$ 86,122			$ 86,122	$ 13,082	$ 2,545		$ 15,627	$ 70,495
1915	Office Furniture & Equipment (10 years)	$ 117,407			$ 117,407	$ 96,207	$ 3,792		$ 99,999	$ 17,409
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 42,873	$ 2,268		$ 45,141	$ 32,718	$ 5,127		$ 37,845	$ 7,296
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 815,244		$ 118,846	$ 696,398	$ 534,172	$ 42,176	$ 118,846	$ 457,502	$ 238,896
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 150,271	$ 580		$ 150,851	$ 126,157	$ 6,924		$ 133,081	$ 17,770
1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ -			$ -	$ -			$ -	$ -
1565	CDM Expenditures	$ -			$ -	$ -			$ -	$ -
	Sub-Total	**$ 10,617,987**	**$ 145,321**	**$ 134,175**	**$ 10,629,133**	**$ 7,543,754**	**$ 333,633**	**$ 118,846**	**$ 7,758,541**	**$ 2,870,592**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	Total PP&E	**$ 10,617,987**	**$ 145,321**	**$ 134,175**	**$ 10,629,133**	**$ 7,543,754**	**$ 333,633**	**$ 118,846**	**$ 7,758,541**	**$ 2,870,592**

Table 2.2.7: Fixed Asset Continuity Schedule (CGAAP) - 2012

			Year	2012						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 29,094	$ 760		$ 29,854	$ 21,050	$ 3,266		$ 24,316	$ 5,538
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 823,377			$ 823,377	$ 727,649	$ 14,633		$ 742,282	$ 81,095
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 1,076,223			$ 1,076,223	$ 911,792	$ 26,133		$ 937,925	$ 138,298
1820	Distribution Station Equipment <50 kV								$ -	$ -
1825	Storage Battery Equipment	$ 9,565			$ 9,565	$ -			$ -	$ 9,565
1830	Poles, Towers & Fixtures	$ 5,012,449	$ 157,180		$ 5,169,629	$ 3,808,991	$ 176,581		$ 3,985,572	$ 1,184,057
1835	Overhead Conductors & Devices	$ 401,309			$ 401,309	$ 750			$ 750	$ 400,559
1840	Underground Conduit	$ 2,183			$ 2,183	$ -			$ -	$ 2,183
1845	Underground Conductors & Devices	$ 89,939	$ 8,000		$ 97,939	$ 22,159	$ 4,005		$ 26,164	$ 71,775
1850	Line Transformers	$ 1,195,739	$ 13,634		$ 1,209,373	$ 1,007,412	$ 30,987		$ 1,038,399	$ 170,974
1855	Services (Overhead & Underground)	$ 7,197			$ 7,197	$ -			$ -	$ 7,197
1860	Meters	$ 391,866	$ -	$ 391,866	$ -	$ 261,293	$ 38,356	$ 299,649	-$ 0	$ 0
1860	Meters (Smart Meters)	$ 841,418			$ 841,418		$ 209,763		$ 209,763	$ 631,655
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 394,273	$ 10,835		$ 405,108	$ 253,393	$ 74		$ 253,467	$ 151,641
1910	Leasehold Improvements	$ 86,122			$ 86,122	$ 15,627	$ 2,545		$ 18,172	$ 67,950
1915	Office Furniture & Equipment (10 years)	$ 117,407			$ 117,407	$ 99,999	$ 3,680		$ 103,679	$ 13,729
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 45,141	$ 1,910		$ 47,051	$ 37,845	$ 4,899		$ 42,744	$ 4,307
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 696,398			$ 696,398	$ 457,502	$ 42,176		$ 499,678	$ 196,720
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 150,851	$ 2,283		$ 153,134	$ 133,081	$ 6,933		$ 140,014	$ 13,120
1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ -	$ 27,672		$ 27,672	$ -			$ -	$ 27,672
1565	CDM Expenditures				$ -	$ -			$ -	$ -
	Sub-Total	**$ 11,470,551**	**$ 222,274**	**$ 391,866**	**$ 11,300,959**	**$ 7,758,541**	**$ 564,032**	**$ 299,649**	**$ 8,022,924**	**$ 3,278,035**
	Less Socialized Renewable Energy Generation Investments (input as negative)		-27672		-$ 27,672				$ -	-$ 27,672
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	Total PP&E	**$ 11,470,551**	**$ 194,602**	**$ 391,866**	**$ 11,273,287**	**$ 7,758,541**	**$ 564,032**	**$ 299,649**	**$ 8,022,924**	**$ 3,250,363**

Table 2.2.8: Fixed Asset Continuity Schedule (Old CGAAP) - 2013 Bridge

			Year	2013						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 29,854	$ 27,500		$ 57,354	$ 24,316	$ 10,115		$ 34,431	$ 22,923
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 823,377	$ 2,000		$ 825,377	$ 742,282	$ 3,483		$ 745,765	$ 79,612
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 1,076,223	$ 2,000		$ 1,078,223	$ 937,925	$ 6,618		$ 944,543	$ 133,680
1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
1825	Storage Battery Equipment	$ 9,565	$ 2,000		$ 11,565	$ -	$ 1,728		$ 1,728	$ 9,838
1830	Poles, Towers & Fixtures	$ 5,169,629	$ 121,891		$ 5,291,520	$ 3,985,572	$ 37,172		$ 4,022,744	$ 1,268,776
1835	Overhead Conductors & Devices	$ 401,309	$ 14,500		$ 415,809	$ 750	$ 15,648		$ 16,398	$ 399,412
1840	Underground Conduit	$ 2,183			$ 2,183	$ -	$ 55		$ 55	$ 2,128
1845	Underground Conductors & Devices	$ 97,939	$ 8,769		$ 106,708	$ 26,164	$ 5,740		$ 31,904	$ 74,804
1850	Line Transformers	$ 1,209,373	$ 15,000		$ 1,224,373	$ 1,038,399	$ 15,627		$ 1,054,026	$ 170,347
1855	Services (Overhead & Underground)	$ 7,197	$ 2,000		$ 9,197	$ -	$ 1,078		$ 1,078	$ 8,119
1860	Meters	$ -			$ -	-$ 0			-$ 0	$ 0
1860	Meters (Smart Meters)	$ 841,418			$ 841,418	$ 209,763	$ 63,166		$ 272,929	$ 568,490
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 405,108	$ 24,000		$ 429,108	$ 253,467	$ 9,265		$ 262,732	$ 166,376
1910	Leasehold Improvements	$ 86,122	$ 1,500		$ 87,622	$ 18,172	$ 4,605		$ 22,777	$ 64,845
1915	Office Furniture & Equipment (10 years)	$ 117,407	$ 3,000		$ 120,407	$ 103,679	$ 2,570		$ 106,248	$ 14,159
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 47,051	$ 5,900		$ 52,951	$ 42,744	$ 2,026		$ 44,770	$ 8,182
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 696,398	$ 120,000	$ 107,038	$ 709,360	$ 499,678	$ 29,858	$ 107,038	$ 422,498	$ 286,862
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 153,134	$ 11,500		$ 164,634	$ 140,014	$ 7,267		$ 147,281	$ 17,353
1945	Measurement & Testing Equipment	$ -	$ 1,500		$ 1,500	$ -	$ 188		$ 188	$ 1,313
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -	$ 900		$ 900	$ -	$ 90		$ 90	$ 810
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ 27,672	$ 35,000		$ 62,672	$ -			$ -	$ 62,672
1565	CDM Expenditures	$ -			$ -	$ -			$ -	$ -
	Sub-Total	**$ 11,300,959**	**$ 398,960**	**$ 107,038**	**$ 11,592,881**	**$ 8,022,924**	**$ 216,296**	**$ 107,038**	**$ 8,132,182**	**$ 3,460,699**
	Less Socialized Renewable Energy Generation Investments (input as negative)	-27672	-35000		-$ 62,672				$ -	-$ 62,672
	Less Other Non Rate-Regulated Utility Assets (input as negative)	0			$ -	0			$ -	$ -
	Total PP&E	**$ 11,273,287**	**$ 363,960**	**$ 107,038**	**$ 11,530,209**	**$ 8,022,924**	**$ 216,296**	**$ 107,038**	**$ 8,132,182**	**$ 3,398,027**

Table 2.2.9: Fixed Asset Continuity Schedule (Old CGAAP) - 2014 Test

			Year	2014						
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 57,354	$ 4,000		$ 61,354	$ 34,431	$ 10,515		$ 44,946	$ 16,408
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 100,000			$ 100,000	$ -			$ -	$ 100,000
1808	Buildings	$ 825,377	$ 5,000		$ 830,377	$ 745,765	$ 3,523		$ 749,288	$ 81,089
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 1,078,223			$ 1,078,223	$ 944,543	$ 6,618		$ 951,161	$ 127,062
1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
1825	Storage Battery Equipment	$ 11,565	$ 2,000		$ 13,565	$ 1,728	$ 1,794		$ 3,522	$ 10,043
1830	Poles, Towers & Fixtures	$ 5,291,520	$ 424,609		$ 5,716,129	$ 4,022,744	$ 41,890		$ 4,064,633	$ 1,651,496
1835	Overhead Conductors & Devices	$ 415,809	$ 51,680		$ 467,489	$ 16,398	$ 16,078		$ 32,476	$ 435,013
1840	Underground Conduit	$ 2,183	$ 27,000		$ 29,183	$ 55	$ 280		$ 334	$ 28,849
1845	Underground Conductors & Devices	$ 106,708	$ 18,549		$ 125,257	$ 31,904	$ 5,972		$ 37,876	$ 87,381
1850	Line Transformers	$ 1,224,373	$ 134,228		$ 1,358,601	$ 1,054,026	$ 17,305		$ 1,071,331	$ 287,270
1855	Services (Overhead & Underground)	$ 9,197	$ 4,000		$ 13,197	$ 1,078	$ 1,128		$ 2,206	$ 10,991
1860	Meters	$ -			$ -	-$ 0			-$ 0	$ 0
1860	Meters (Smart Meters)	$ 841,418	$ 5,750		$ 847,168	$ 272,929	$ 63,357		$ 336,286	$ 510,882
1905	Land	$ -			$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ 429,108	$ 7,500		$ 436,608	$ 262,732	$ 9,359		$ 272,091	$ 164,517
1910	Leasehold Improvements	$ 87,622			$ 87,622	$ 22,777	$ 4,605		$ 27,382	$ 60,240
1915	Office Furniture & Equipment (10 years)	$ 120,407	$ 6,500		$ 126,907	$ 106,248	$ 2,786		$ 109,034	$ 17,873
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 52,951	$ 15,500		$ 68,451	$ 44,770	$ 3,576		$ 48,345	$ 20,106
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ 709,360	$ 50,000	$ 21,142	$ 738,218	$ 422,498	$ 31,525	$ 21,142	$ 432,880	$ 305,338
1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 164,634	$ 10,500		$ 175,134	$ 147,281	$ 7,792		$ 155,073	$ 20,061
1945	Measurement & Testing Equipment	$ 1,500	$ 3,500		$ 5,000	$ 188	$ 406		$ 594	$ 4,406
1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
1955	Communications Equipment	$ 900			$ 900	$ 90	$ 90		$ 180	$ 720
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
1531	REG Capital Deferral Account	$ 62,672	$ 50,000		$ 112,672	$ -			$ -	$ 112,672
1565	CDM Expenditures				$ -	$ -			$ -	$ -
	Sub-Total	**$ 11,592,881**	**$ 820,316**	**$ 21,142**	**$ 12,392,055**	**$ 8,132,182**	**$ 228,599**	**$ 21,142**	**$ 8,339,639**	**$ 4,052,416**
	Less Socialized Renewable Energy Generation Investments (input as negative)	$ (62,672.00)	$ (50,000)		-$ 112,672	$ -			$ -	-$ 112,672
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -	$ -			$ -	$ -
	Total PP&E	**$ 11,530,209**	**$ 770,316**	**$ 21,142**	**$ 12,279,383**	**$ 8,132,182**	**$ 228,599**	**$ 21,142**	**$ 8,339,639**	**$ 3,939,744**

Gross Assets Table:

Table 2.2.10: Gross Assets 1 of 2 (CGAAP)

OEB	Description	2006 Approved	2006 Actual	Variance 2006 Approved to 2006 Actual	2007 Actual	Variance 2006 Actual to 2007 Actual	2008 Actual	Variance 2007 Actual to 2008 Actual	2009 Actual	Variance 2008 Actual to 2009 Actual	2010 Actual	Variance 2009 Actual to 2010 Actual
1611	Computer Software (Formally known as Account 1925)	$503	$2,905	$2,402	$4,995	$2,090	$20,535	$15,540	$25,765	$5,230	$28,219	$2,454
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$100,000	$100,000	$0	$100,000	$0	$100,000	$0	$100,000	$0	$100,000	$0
1808	Buildings	$817,909	$817,909	$0	$817,909	$0	$817,909	$0	$818,141	$232	$819,621	$1,480
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$1,027,067	$1,066,073	$39,006	$1,061,323	($4,750)	$1,071,427	$10,104	$1,071,904	$477	$1,076,223	$4,319
1825	Storage Battery Equipment	$0	$8,869	$8,869	$8,869	$0	$8,869	$0	$8,869	$0	$8,869	$0
1830	Poles, Towers & Fixtures	$4,309,166	$4,447,660	$138,494	$4,521,382	$73,722	$4,630,059	$108,677	$4,733,536	$103,477	$4,888,151	$154,615
1835	Overhead Conductors & Devices	$265,517	$353,731	$88,214	$392,099	$38,368	$395,744	$3,645	$400,806	$5,062	$401,309	$503
1840	Underground Conduit	$2,183	$2,183	$0	$2,183	$0	$2,183	$0	$2,183	$0	$2,183	$0
1845	Underground Conductors & Devices	$30,712	$43,155	$12,443	$52,355	$9,200	$65,602	$13,247	$72,123	$6,521	$83,428	$11,305
1850	Line Transformers	$1,050,113	$1,124,992	$74,878	$1,165,000	$40,008	$1,182,158	$17,158	$1,223,509	$41,351	$1,208,459	($15,050)
1855	Services (Overhead & Underground)	$6,715	$7,197	$482	$7,197	$0	$7,197	$0	$7,197	$0	$7,197	$0
1860	Meters	$351,835	$382,601	$30,766	$389,291	$6,690	$390,590	$1,299	$391,866	$1,276	$391,866	$0
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$250,639	$250,639	($0)	$267,513	$16,874	$267,513	$0	$376,953	$109,440	$390,545	$13,592
1910	Leasehold Improvements	$3,110	$10,507	$7,397	$10,507	$0	$10,507	$0	$10,656	$149	$86,122	$75,466
1915	Office Furniture & Equipment (10 years)	$83,493	$100,831	$17,338	$101,488	$657	$114,421	$12,933	$115,609	$1,188	$117,407	$1,799
1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$50,579	$29,029	($21,550)	$31,084	$2,055	$32,722	$1,638	$34,034	$1,312	$42,873	$8,839
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$517,934	$658,607	$140,673	$569,344	($89,263)	$569,344	$0	$569,344	$0	$815,244	$245,900
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$100,680	$140,662	$39,982	$143,053	$2,391	$145,714	$2,661	$147,784	$2,070	$150,271	$2,487
1945	Measurement & Testing Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1531	Renewable Connection Capital Deferral Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1556	CDM Expenditures	$19,000	$0	($19,000)	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-Total	**$8,987,154**	**$9,547,550**	**$560,395**	**$9,645,591**	**$98,042**	**$9,832,493**	**$186,902**	**$10,110,278**	**$277,785**	**$10,617,987**	**$507,709**
	Less Socialized Renewable Energy Generation Investments (input as negative)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Less Other Non Rate-Regulated Utility Assets (input as negative)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total PP&E	**$8,987,154**	**$9,547,550**	**$560,395**	**$9,645,591**	**$98,042**	**$9,832,493**	**$186,902**	**$10,110,278**	**$277,785**	**$10,617,987**	**$507,709**

Table 2.2.10: Gross Assets 2 of 2 (CGAAP)

OEB	Description	2011 Actual	Variance 2010 Actual to 2011 Actual	2012 Actual	Variance 2011 Actual to 2012 Actual	2013 Bridge	Variance 2012 Actual to 2013 Bridge	2014 Test	Variance 2013 Bridge to 2014 Test
1611	Computer Software (Formally known as Account 1925)	$29,094	$875	$29,854	$760	$57,354	$27,500	$61,354	$4,000
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$100,000	$0	$100,000	$0	$100,000	$0	$100,000	$0
1808	Buildings	$823,377	$3,756	$823,377	$0	$825,377	$2,000	$830,377	$5,000
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$1,076,223	$1,076,223	$1,078,223	$2,000	$1,078,223	$0
1820	Distribution Station Equipment <50 kV	$1,076,223	$0	$0	($1,076,223)	$0	$0	$0	$0
1825	Storage Battery Equipment	$9,565	$696	$9,565	$0	$11,565	$2,000	$13,565	$2,000
1830	Poles, Towers & Fixtures	$5,012,449	$124,298	$5,169,629	$157,180	$5,291,520	$121,891	$5,716,129	$424,609
1835	Overhead Conductors & Devices	$401,309	$0	$401,309	$0	$415,809	$14,500	$467,489	$51,680
1840	Underground Conduit	$2,183	$0	$2,183	$0	$2,183	$0	$29,183	$27,000
1845	Underground Conductors & Devices	$89,939	$6,511	$97,939	$8,000	$106,708	$8,769	$125,257	$18,549
1850	Line Transformers	$1,195,739	($12,720)	$1,209,373	$13,634	$1,224,373	$15,000	$1,358,601	$134,228
1855	Services (Overhead & Underground)	$7,197	$0	$7,197	$0	$9,197	$2,000	$13,197	$4,000
1860	Meters	$391,866	$0	$0	($391,866)	$0	$0	$0	$0
1860	Meters (Smart Meters)	$0	$0	$841,418	$841,418	$841,418	$0	$847,168	$5,750
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$394,273	$3,728	$405,108	$10,835	$429,108	$24,000	$436,608	$7,500
1910	Leasehold Improvements	$86,122	$0	$86,122	$0	$87,622	$1,500	$87,622	$0
1915	Office Furniture & Equipment (10 years)	$117,407	$0	$117,407	$0	$120,407	$3,000	$126,907	$6,500
1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$45,141	$2,268	$47,051	$1,910	$52,951	$5,900	$68,451	$15,500
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$696,398	($118,846)	$696,398	$0	$709,360	$12,962	$738,218	$28,858
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$150,851	$580	$153,134	$2,283	$164,634	$11,500	$175,134	$10,500
1945	Measurement & Testing Equipment	$0	$0	$0	$0	$1,500	$1,500	$5,000	$3,500
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$0	$0	$0	$0	$900	$900	$900	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	$0	$0	$0	$0	$0	$0	$0	$0
1531	Renewable Connection Capital Deferral Account	$0	$0	$27,672	$27,672	$62,672	$35,000	$112,672	$50,000
1556	CDM Expenditures	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-Total	**$10,629,133**	**$11,146**	**$11,300,959**	**$671,826**	**$11,592,881**	**$291,922**	**$12,392,055**	**$799,174**
	Less Socialized Renewable Energy Generation Investments (input as negative)	$0	$0	($27,672)	($27,672)	($62,672)	($35,000)	($112,672)	($50,000)
	Less Other Non Rate-Regulated Utility Assets (input as negative)	$0	$0	$0	$0	$0	$0	$0	$0
	Total PP&E	**$10,629,133**	**$11,146**	**$11,273,287**	**$644,154**	**$11,530,209**	**$256,922**	**$12,279,383**	**$749,174**

Variance Analysis on Gross Assets:

Table 2.2.10 above shows the year-to-year variances in gross assets. The Gross Asset Variance analysis for these variances is provided as follows, and can also be found in Exhibit 2, Tab 2, Schedule 3.

2006 Board Approved vs. 2006 Actual

- Variance $560,395
  - Please note that 2006 Board approved amounts are based on 2004 historical amounts, which is causing the large variance between 2006 actual and 2006 Board comparisons, as there is a two year timing difference in the data sets.

2006 Actual vs. 2007 Actual

- Variance: $98,042
  - Capital additions less disposals as per Table 2.2.2: Fixed Asset Continuity Schedule 2007, a summary of the resulting net variances is provided below. Significant net increases include; $73,722 to Poles, Towers & Fixtures; $40,008 to Line Transformers; and $38,368 to Overhead Conductor and Devices. Significant net decreases include $89,263 under Transportation Equipment, due to the disposal of a line truck.

Description	Variance 2006 Actual to 2007 Actual
Computer Software (Formally known as Account 1925)	$2,090
Distribution Station Equipment <50 kV	($4,750)
Poles, Towers & Fixtures	$73,722
Overhead Conductors & Devices	$38,368
Underground Conductors & Devices	$9,200
Line Transformers	$40,008
Meters	$6,690
Buildings & Fixtures	$16,874
Office Furniture & Equipment (10 years)	$657
Computer Equipment - Hardware	$2,055
Transportation Equipment	($89,263)
Tools, Shop & Garage Equipment	$2,391
Sub Total	**$98,042**

2007 Actual vs. 2008 Actual

- Variance: $186,902
  - Capital additions less disposals as per Table 2.2.3: Fixed Asset Continuity Schedule 2008, a summary of the resulting net variances is provided below. Significant net increases include $108,667 to Poles, Towers & Fixtures, and there were no significant disposals, and as such no net decreases.

Description	Variance 2007 Actual to 2008 Actual
Computer Software (Formally known as Account 1925)	$15,540
Distribution Station Equipment <50 kV	$10,104
Poles, Towers & Fixtures	$108,677
Overhead Conductors & Devices	$3,645
Underground Conductors & Devices	$13,247
Line Transformers	$17,158
Meters	$1,299
Office Furniture & Equipment (10 years)	$12,933
Computer Equipment - Hardware	$1,638
Tools, Shop & Garage Equipment	$2,661
Sub-Total	**$186,902**

2008 Actual vs. 2009 Actual

- Variance: $277,785
  - Capital additions less disposals as per Table 2.2.4: Fixed Asset Continuity Schedule 2009, a summary of the resulting net variances is provided below. Significant additions resulting in net increases include; $103,477 to Poles, Towers & Fixtures; and $109,440 to Buildings and Fixture, for FFPC's Operational Centre Expansion project. There were no significant disposals, and as such no net decreases.

Description	Variance 2008 Actual to 2009 Actual
Computer Software (Formally known as Account 1925)	$5,230
Buildings	$232
Distribution Station Equipment <50 kV	$477
Poles, Towers & Fixtures	$103,477
Overhead Conductors & Devices	$5,062
Underground Conductors & Devices	$6,521
Line Transformers	$41,351
Meters	$1,276
Buildings & Fixtures	$109,440
Leasehold Improvements	$149
Office Furniture & Equipment (10 years)	$1,188
Computer Equipment - Hardware	$1,312
Tools, Shop & Garage Equipment	$2,070
Sub-Total	**$277,785**

2009 Actual vs. 2010 Actual

- Variance: $507,709
  - Capital additions less disposals as per Table 2.2.5: Fixed Asset Continuity Schedule 2010, a summary of the resulting net variances is provided below. Significant additions resulting in net increases include; $154,615 to Poles, Towers & Fixtures; $75,466 to Leasehold Improvements, for the installation of an emergency backup generator to power FFPC's Main Office Building; and $245,900 to Transportation Equipment, for the purchase of a Digger Derrick Truck. Significant disposals include end of life transformers, in the amount of $15,339, resulting in a net decrease of $15,050.

Description	Variance 2009 Actual to 2010 Actual
Computer Software (Formally known as Account 1925)	$2,454
Buildings	$1,480
Distribution Station Equipment <50 kV	$4,319
Poles, Towers & Fixtures	$154,615
Overhead Conductors & Devices	$503
Underground Conductors & Devices	$11,305
Line Transformers	($15,050)
Buildings & Fixtures	$13,592
Leasehold Improvements	$75,466
Office Furniture & Equipment (10 years)	$1,799

Computer Equipment - Hardware	$8,839
Transportation Equipment	$245,900
Tools, Shop & Garage Equipment	$2,487
Sub-Total	**$507,709**

2010 Actual vs. 2011 Actual

- Variance: $11,146
  - Capital additions less disposals as per Table 2.2.6: Fixed Asset Continuity Schedule 2011, a summary of the resulting net variances is provided below. Significant additions resulting in net increases include $124,298 to Poles, Towers & Fixtures. FFPC also disposed of a Digger Derrick truck, resulting in a net decrease of $118,846 being recorded to Transportation Equipment.

Description	Variance 2010 Actual to 2011 Actual
Computer Software (Formally known as Account 1925)	$875
Buildings	$3,756
Storage Battery Equipment	$696
Poles, Towers & Fixtures	$124,298
Underground Conductors & Devices	$6,511
Line Transformers	($12,720)
Buildings & Fixtures	$3,728
Computer Equipment - Hardware	$2,268
Transportation Equipment	($118,846)
Tools, Shop & Garage Equipment	$580
Sub-Total	**$11,146**

2011 Actual vs. 2012 Actual

- Variance: $671,826
  - Capital additions less disposals as per Table 2.2.7: Fixed Asset Continuity Schedule 2012, a summary of the resulting net variances is provided below. Significant additions include; $841,418 for the inclusion of Smart Meters in FFPC's asset base; and $157,180 to Poles, Towers & Fixtures. FFPC's transformer station classification was also corrected to reflect that it is a greater than 50 kV station, as opposed to a less than 50 kV station. In 2012,

FFPC also formally disposed of its traditional metering assets due to their replacement with Smart Meters and as such, $391,866 was recorded to Meters Disposal.

Description	Variance 2011 Actual to 2012 Actual
Computer Software (Formally known as Account 1925)	$760
Transformer Station Equipment >50 kV	$1,076,223
Distribution Station Equipment <50 kV	($1,076,223)
Poles, Towers & Fixtures	$157,180
Underground Conductors & Devices	$8,000
Line Transformers	$13,634
Meters	($391,866)
Meters (Smart Meters)	$841,418
Buildings & Fixtures	$10,835
Computer Equipment - Hardware	$1,910
Tools, Shop & Garage Equipment	$2,283
Renewable Connection Capital Deferral Account	$27,672
Sub-Total	**$671,826**

2012 Actual vs. 2013 Bridge

- Variance: $291,922
  - Capital additions less disposals as per Table 2.2.8: Fixed Asset Continuity Schedule 2013 - Bridge Year, a summary of the resulting net variances is provided below. Significant additions include; $121,891 to Poles, Towers & Fixtures; and $120,000 (with an offsetting disposal of 107,038) to Transportation Equipment, for the replacement of a Single Bucket Truck. Material disposal include $107,038 recorded to Transportation Equipment, from the replacement of the Single Bucket Truck, resulting in a net increase of $12,962.

Description	Variance 2012 Actual to 2013 Bridge
Computer Software (Formally known as Account 1925)	$27,500
Buildings	$2,000
Transformer Station Equipment >50 kV	$2,000
Storage Battery Equipment	$2,000
Poles, Towers & Fixtures	$121,891
Overhead Conductors & Devices	$14,500
Underground Conductors & Devices	$8,769
Line Transformers	$15,000
Services (Overhead & Underground)	$2,000
Buildings & Fixtures	$24,000
Leasehold Improvements	$1,500
Office Furniture & Equipment (10 years)	$3,000
Computer Equipment - Hardware	$5,900
Transportation Equipment	$12,962
Tools, Shop & Garage Equipment	$11,500
Measurement & Testing Equipment	$1,500
Communications Equipment	$900
Renewable Connection Capital Deferral Account	$35,000
Sub-Total	**$291,922**

2013 Bridge vs. 2014 Test

- Variance: $799,194
  - Capital additions less disposals as per Table 2.2.9: Fixed Asset Continuity Schedule - 2014 Test Year, a summary of the resulting net variances is provided below. Significant additions include; $424,609 to Poles, Towers & Fixtures, due largely to planned feeder expansions to eliminate Long Term Load Transfers; $134,228 to Line Transformers; and $50,000 to Transportation Equipment, for the replacement of a Cable Reel & Tensioning Trailer. Disposals include the Cable Reel & Tensioning Trailer at $21,142, resulting in a net increase of $28,858 to transportation equipment.

Description	Variance 2013 Bridge to 2014 Test
Computer Software (Formally known as Account 1925)	$4,000
Buildings	$5,000
Storage Battery Equipment	$2,000
Poles, Towers & Fixtures	$424,609
Overhead Conductors & Devices	$51,680
Underground Conduit	$27,000
Underground Conductors & Devices	$18,549
Line Transformers	$134,228
Services (Overhead & Underground)	$4,000
Meters (Smart Meters)	$5,750
Buildings & Fixtures	$7,500
Office Furniture & Equipment (10 years)	$6,500
Computer Equipment - Hardware	$15,500
Transportation Equipment	$28,858
Tools, Shop & Garage Equipment	$10,500
Measurement & Testing Equipment	$3,500
Renewable Connection Capital Deferral Account	$50,000
Sub-Total	**$799,174**

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Accumulated Amortization Table:

Table 2.2.11: Accumulated Amortization 1 of 2 (CGAAP)

OEB	Description	2006 Approved	2006 Actual	Variance 2006 Approved to 2006 Actual	2007 Actual	Variance 2006 Actual to 2007 Actual	2008 Actual	Variance 2007 Actual to 2008 Actual	2009 Actual	Variance 2008 Actual to 2009 Actual	2010 Actual	Variance 2009 Actual to 2010 Actual
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0	$956	$956	$9,252	$8,296	$17,633	$8,381
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings	$623,746	$666,864	$43,118	$676,099	$9,235	$685,333	$9,234	$698,954	$13,621	$713,152	$14,198
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$704,602	$781,735	$77,133	$807,491	$25,756	$833,500	$26,009	$859,526	$26,026	$885,659	$26,133
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$2,349,593	$2,862,402	$512,809	$3,072,122	$209,720	$3,263,315	$191,193	$3,439,413	$176,098	$3,621,716	$182,303
1835	Overhead Conductors & Devices	$750	$750	$0	$750	$0	$750	$0	$750	$0	$750	$0
1840	Underground Conduit	$3,836	$0	($3,836)	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors & Devices	$0	$7,185	$7,185	$9,366	$2,181	$12,077	$2,711	$15,049	$2,972	$18,474	$3,425
1850	Line Transformers	$717,977	$801,219	$83,242	$846,116	$44,897	$891,699	$45,583	$938,525	$46,826	$969,556	$31,031
1855	Services (Overhead & Underground)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$189,946	$216,225	$26,279	$230,248	$14,023	$244,323	$14,075	$258,449	$14,126	$261,293	$2,844
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$249,335	$250,789	$1,454	$251,516	$727	$252,243	$727	$252,969	$726	$253,187	$218
1910	Leasehold Improvements	$1,246	$5,447	$4,201	$7,548	$2,101	$9,649	$2,101	$10,537	$888	$13,082	$2,545
1915	Office Furniture & Equipment (10 years)	$73,524	$79,691	$6,167	$82,931	$3,240	$87,463	$4,532	$92,115	$4,652	$96,207	$4,092
1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$44,368	$19,783	($24,585)	$25,590	$5,807	$32,718	$7,128	$32,718	$0	$32,718	$0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$443,831	$389,011	($54,820)	$365,279	($23,732)	$426,077	$60,798	$473,495	$47,418	$534,172	$60,677
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$86,554	$98,098	$11,544	$104,935	$6,837	$111,932	$6,997	$119,005	$7,073	$126,157	$7,152
1945	Measurement & Testing Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
etc.		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-Total	**$5,489,308**	**$6,179,199**	**$689,891**	**$6,479,991**	**$300,792**	**$6,852,035**	**$372,044**	**$7,200,755**	**$348,721**	**$7,543,754**	**$342,999**
	Less Socialized Renewable Energy Generation Investments (input as negative)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total PP&E	**$5,489,308**	**$6,179,199**	**$689,891**	**$6,479,991**	**$300,792**	**$6,852,035**	**$372,044**	**$7,200,755**	**$348,721**	**$7,543,754**	**$342,999**

Table 2.2.11: Accumulated Amortization 2 of 2 (CGAAP)

OEB	Description	2011 Actual	Variance 2010 Actual to 2011 Actual	2012 Actual	Variance 2011 Actual to 2012 Actual	2013 Bridge	Variance 2012 Actual to 2013 Bridge	2014 Test	Variance 2013 Bridge to 2014 Test
1611	Computer Software (Formally known as Account 1925)	$21,050	$3,417	$24,316	$3,266	$34,431	$10,115	$44,946	$10,515
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings	$727,649	$14,497	$742,282	$14,633	$745,765	$3,483	$749,288	$3,523
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$937,925	$937,925	$944,543	$6,618	$951,161	$6,618
1820	Distribution Station Equipment <50 kV	$911,792	$26,133	$0	($911,792)	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$1,728	$1,728	$3,522	$1,794
1830	Poles, Towers & Fixtures	$3,808,991	$187,275	$3,985,572	$176,581	$4,022,744	$37,172	$4,064,633	$41,890
1835	Overhead Conductors & Devices	$750	$0	$750	$0	$16,398	$15,648	$32,476	$16,078
1840	Underground Conduit	$0	$0	$0	$0	$55	$55	$334	$280
1845	Underground Conductors & Devices	$22,159	$3,685	$26,164	$4,005	$31,904	$5,740	$37,876	$5,972
1850	Line Transformers	$1,007,412	$37,856	$1,038,399	$30,987	$1,054,026	$15,627	$1,071,331	$17,305
1855	Services (Overhead & Underground)	$0	$0	$0	$0	$1,078	$1,078	$2,206	$1,128
1860	Meters	$261,293	$0	($0)	($261,293)	($0)	$0	($0)	$0
1860	Meters (Smart Meters)	$0	$0	$209,763	$209,763	$272,929	$63,166	$336,286	$63,357
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$253,393	$206	$253,467	$74	$262,732	$9,265	$272,091	$9,359
1910	Leasehold Improvements	$15,627	$2,545	$18,172	$2,545	$22,777	$4,605	$27,382	$4,605
1915	Office Furniture & Equipment (10 years)	$99,999	$3,792	$103,679	$3,680	$106,248	$2,570	$109,034	$2,786
1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$37,845	$5,127	$42,744	$4,899	$44,770	$2,026	$48,345	$3,576
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$457,502	($76,670)	$499,678	$42,176	$422,498	($77,180)	$432,880	$10,383
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$133,081	$6,924	$140,014	$6,933	$147,281	$7,267	$155,073	$7,792
1945	Measurement & Testing Equipment	$0	$0	$0	$0	$188	$188	$594	$406
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$0	$0	$0	$0	$90	$90	$180	$90
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	$0	$0	$0	$0	$0	$0	$0	$0
etc.		$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0
	Sub-Total	**$7,758,541**	**$214,787**	**$8,022,924**	**$264,383**	**$8,132,182**	**$109,258**	**$8,339,639**	**$207,457**
	Less Socialized Renewable Energy Generation Investments (input as negative)	$0	$0		$0		$0		$0
	Less Other Non Rate-Regulated Utility Assets (input as negative)	$0	$0	$0	$0	$0	$0	$0	$0
	Total PP&E	**$7,758,541**	**$214,787**	**$8,022,924**	**$264,383**	**$8,132,182**	**$109,258**	**$8,339,639**	**$207,457**

Variance Analysis on Accumulated Amortization:

Changes in accumulated amortization are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identified assets.

Table 2.2.11 shows the changes in accumulated amortization from 2006 Actual to the 2014 Test Year. It is important to note that the following variance analysis for the 2013 Bridge and 2014 Test Years are based on FFPC's old CGAAP depreciation schedule. The Accumulated Depreciation Variance analysis for these variances is provided as follows, and can also be found in Exhibit 2, Tab 3, Schedule 5. Please refer to Exhibit 4, Tab 4, Schedule 1 for details of annual amortization expense for each asset account.

2006 Approved vs. 2006 Actual

- Variance $689,891
    - Please note that 2006 Board approved amounts are based on 2004 historical amounts, which is causing the large variance between 2006 actual and 2006 Board comparisons, as there is a two year timing difference in the data sets.

2006 Actual vs. 2007 Actual

- Variance $300,792
    - Depreciation of assets less disposals of as shown in Table 2.2.2: Fixed Asset Continuity Schedule - 2007, a summary of the resulting net variances is provided below. Significant additions to depreciation include; $209,720 to Poles, Towers & Fixtures; $44,897 to Line Transformers and $67,081 to Transportation Equipment. Significant disposals include $90,813 for a line truck, resulting in a net decrease of $23,732 under Transportation Equipment.

Description	Variance 2006

	Actual to 2007 Actual
Buildings	$9,235
Distribution Station Equipment <50 kV	$25,756
Poles, Towers & Fixtures	$209,720
Underground Conductors & Devices	$2,181
Line Transformers	$44,897
Meters	$14,023
Buildings & Fixtures	$727
Leasehold Improvements	$2,101
Office Furniture & Equipment (10 years)	$3,240
Computer Equipment - Hardware	$5,807
Transportation Equipment	($23,732)
Tools, Shop & Garage Equipment	$6,837
Sub-Total	**$300,792**

2007 Actual vs. 2008 Actual

- Variance $372,044
  - Depreciation of assets less disposals as shown in Table 2.2.3: Fixed Asset Continuity Schedule - 2008, a summary of the resulting net variances is provided below. Significant additions include; $191,193 to Poles, Towers & Fixtures; $45,583 to Line Transformers; and $60,798 to Transportation Equipments. There were no disposals recorded in 2008.

Description	Variance 2007 Actual to 2008 Actual
Computer Software (Formally known as Account 1925)	$956
Buildings	$9,234
Distribution Station Equipment <50 kV	$26,009
Poles, Towers & Fixtures	$191,193
Underground Conductors & Devices	$2,711
Line Transformers	$45,583
Meters	$14,075
Buildings & Fixtures	$727
Leasehold Improvements	$2,101
Office Furniture & Equipment (10 years)	$4,532
Computer Equipment - Hardware	$7,128
Transportation Equipment	$60,798
Tools, Shop & Garage Equipment	$6,997
Sub-Total	**$372,044**

2008 Actual vs. 2009 Actual

- Variance $348,721
  - Depreciation of assets less disposals as shown in Table 2.2.4: Fixed Asset Continuity Schedule - 2009, a summary of the resulting net variances is provided below. Significant additions include $176,098 to Poles, Towers & Fixtures; $46,826 to Line Transformers and $47,418 to Transportation Equipment. There were no disposals recorded in 2009.

Description	Variance 2008 Actual to 2009 Actual
Computer Software (Formally known as Account 1925)	$8,296
Buildings	$13,621
Distribution Station Equipment <50 kV	$26,026
Poles, Towers & Fixtures	$176,098
Underground Conductors & Devices	$2,972
Line Transformers	$46,826
Meters	$14,126
Buildings & Fixtures	$726
Leasehold Improvements	$888
Office Furniture & Equipment (10 years)	$4,652
Transportation Equipment	$47,418
Tools, Shop & Garage Equipment	$7,073
Sub-Total	**$348,721**

2009 Actual vs. 2010 Actual

- Variance $342,999
  - Depreciation of assets less disposals as shown in Table 2.2.5: Fixed Asset Continuity Schedule - 2010, a summary of the resulting net variances is provided below. Significant additions include $182,303 to Poles, Towers & Fixtures; $45,150 to Line Transformers and $60,677 to Transportation Equipment. Disposals included $14,119 for Line Transformers, and as such the resulting net increase to Line Transformers was $31,031

Description	Variance 2009 Actual to 2010 Actual
Computer Software (Formally known as Account 1925)	$8,381
Buildings	$14,198
Distribution Station Equipment <50 kV	$26,133
Poles, Towers & Fixtures	$182,303
Underground Conductors & Devices	$3,425
Line Transformers	$31,031
Meters	$2,844
Buildings & Fixtures	$218
Leasehold Improvements	$2,545
Office Furniture & Equipment (10 years)	$4,092
Transportation Equipment	$60,677
Tools, Shop & Garage Equipment	$7,152
Sub-Total	**$342,999**

2010 Actual vs. 2011 Actual

- Variance $214,787
  - Depreciation of assets less disposals as shown in Table 2.2.6: Fixed Asset Continuity Schedule - 2011, a summary of the resulting net variances is provided below. Significant additions include $187,275 to Poles, Towers & Fixtures; $37,856 to Line Transformers and $42,176 to Transportation Equipment. Significant disposals include $118,846 to Transportation Equipment to reflect the disposal of FFPC's end of life Digger Derrick Truck, as well as $15,329 for the disposal of failed Line Transformer. The resulting net decrease to Transportation equipment was $76,670.

Description	Variance 2010 Actual to 2011 Actual
Computer Software (Formally known as Account 1925)	$3,417
Buildings	$14,497
Distribution Station Equipment <50 kV	$26,133
Poles, Towers & Fixtures	$187,275
Underground Conductors & Devices	$3,685
Line Transformers	$37,856
Buildings & Fixtures	$206
Leasehold Improvements	$2,545
Office Furniture & Equipment (10 years)	$3,792
Computer Equipment - Hardware	$5,127
Transportation Equipment	($76,670)
Tools, Shop & Garage Equipment	$6,924
Sub-Total	**$214,787**

2011 Actual vs. 2012 Actual

- Variance $264,383
  - Depreciation of assets less disposals as shown in Table 2.2.7: Fixed Asset Continuity Schedule - 2012, a summary of the resulting net variances is provided below. Significant additions include; $176,581 to Poles, Towers & Fixtures; $56,095 to Meters (Smart Meters); $30,987 to Line Transformers; and $42,176 to Transportation Equipment. FFPC also corrected the classification of its transformer station from a less than 50k station to a greater than 50 kV station. Significant disposals include $299,649 to Meters, reflecting the disposal of conventional metering equipment utilized prior to the acquisition of Smart Meters.

Description	Variance 2011 Actual to 2012 Actual
Computer Software (Formally known as Account 1925)	$3,266
Buildings	$14,633
Transformer Station Equipment >50 kV	$937,925
Distribution Station Equipment <50 kV	($911,792)
Poles, Towers & Fixtures	$176,581
Underground Conductors & Devices	$4,005
Line Transformers	$30,987
Meters	($261,293)
Meters (Smart Meters)	$209,763
Buildings & Fixtures	$74
Leasehold Improvements	$2,545
Office Furniture & Equipment (10 years)	$3,680
Computer Equipment - Hardware	$4,899
Transportation Equipment	$42,176
Tools, Shop & Garage Equipment	$6,933
Sub-Total	**$264,383**

2012 Actual vs. 2013 Bridge

- Variance $109,258
  - Depreciation of assets less disposals as shown in Table 2.2.8: Fixed Asset Continuity Schedule - 2013 Bridge Year, a summary of the resulting net variances is provided below. Significant additions include; $29,858 to Transportation Equipment, $37,172 to Poles, Towers & Fixtures; and $63,166 to Meters (Smart Meters). Significant disposals include $107,038 under Transportation Equipment, for the disposal of a Single Bucket Truck, resulting in a net amortization decrease for Transportation equipment of $77,180.

Description	Variance 2012 Actual to 2013 Bridge
Computer Software (Formally known as Account 1925)	$10,115
Buildings	$3,483
Transformer Station Equipment >50 kV	$6,618
Storage Battery Equipment	$1,728
Poles, Towers & Fixtures	$37,172
Overhead Conductors & Devices	$15,648
Underground Conduit	$55
Underground Conductors & Devices	$5,740
Line Transformers	$15,627
Services (Overhead & Underground)	$1,078
Meters (Smart Meters)	$63,166
Buildings & Fixtures	$9,265
Leasehold Improvements	$4,605
Office Furniture & Equipment (10 years)	$2,570
Computer Equipment - Hardware	$2,026
Transportation Equipment	($77,180)
Tools, Shop & Garage Equipment	$7,267
Measurement & Testing Equipment	$188
Communications Equipment	$90
Sub-Total	**$109,258**

2013 Bridge vs. 2014 Test

- Variance $207,457
  - Depreciation of assets less disposals as shown in Table 2.2.9: Fixed Asset Continuity Schedule - 2013 Test Year, a summary of the resulting net variances is provided below. Significant additions include; $31,525 to Transportation Equipment, $41,890 to Poles, Towers & Fixtures; and $63,357 to Meters (Smart Meters). Significant disposals include $21,142 recorded to Transportation Equipment, for the disposal of a Cable Reel & Tensioning Trailer, resulting in a net increase of $10,383 for Transpiration Equipment.

Description	Variance 2013 Bridge to 2014 Test
Computer Software (Formally known as Account 1925)	$10,515
Buildings	$3,523
Transformer Station Equipment >50 kV	$6,618
Storage Battery Equipment	$1,794
Poles, Towers & Fixtures	$41,890
Overhead Conductors & Devices	$16,078
Underground Conduit	$280
Underground Conductors & Devices	$5,972
Line Transformers	$17,305
Services (Overhead & Underground)	$1,128
Meters (Smart Meters)	$63,357
Buildings & Fixtures	$9,359
Leasehold Improvements	$4,605
Office Furniture & Equipment (10 years)	$2,786
Computer Equipment - Hardware	$3,576
Transportation Equipment	$10,383
Tools, Shop & Garage Equipment	$7,792
Measurement & Testing Equipment	$406
Communications Equipment	$90
Sub-Total	**$207,457**

CAPITAL EXPENDITURES:

Overview of Capital Expenditures

In managing its distribution system assets, FFPC's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service expectations. This Application incorporates FFPC's 2014 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

FFPC considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, risk and impact of failure, loading, customer connection requirements, system configuration, line loss reduction, outage mitigation and procuring the lowest cost of commodity to determine investment needs in the system.
On an annual basis, FFPC reviews capital projects identified for potential implementation and prioritizes each project based on a defined criteria basis. The management team annually reviews FFPC's multiyear Asset Management Plan ("DS Plan"), and prioritizes projects in order from highest to lowest priority, and then proceeds with project implementation on an "as-needed" basis.

With the recent development and implementation of formalized asset management and capital planning processes, FFPC has taken a new approach to identifying, prioritizing and categorizing system renewal projects driven by assets reaching the end of their useful service life. It is worth mentioning that FFPC also subjects its General Plant assets to these processes, to determine which assets require replacement or refurbishments just like distribution related assets.

FFPC selects and prioritizes its capital investments projects based on the degree to which they achieve the following objectives:

1. Ensuring that the health and safety of employees and the public is maintained
2. Eliminate or mitigate threats to the environment
3. Ensuring compliance to regulatory and legal obligations
4. Meeting the needs and preference of customers
5. Replacing, sustaining or retiring assets that are at the end of their useful life
6. Improving operational efficiency and effectiveness

In the past, distribution system renewal projects were typically performed on a Region or Zone Basis, such as "Scott Street Pole Replacements"; however, with availability of intricate asset specific dimensional and condition data, FFPC has transitioned to an asset class investment approach based on the results of the asset management and capital planning processes. Using this approach, FFPC limits replacements to the "worst in class" assets and does not replace assets that are in the same "zone" which may still have significant useful life remaining.

FFPC's Asset Management Plan is documented in detail under Section 5.3 of the DS Plan, which is attached to Exhibit 2 as Appendix 2A.

In addition to the capital needs of FFPC's asset base, system maintenance needs are also planned on a priority basis according to the findings of FFPC's Maintenance Inspection Program. The same preparation and consideration steps are undertaken before the final recommended budget amounts are established. Further information on FFPC's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

Investment Categories

Historically, FFPC's assets have fallen into two broad categories – ***Distribution Plant***, which includes assets such as municipal transformer stations (FFPC's High Voltage Station "Fort Frances MTS"), poles, conductors, overhead and underground electricity distribution infrastructure, transformers, and meters. The second is ***General Plant*** which includes modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.

Since the release of Chapter 5 – Consolidated Distribution System Plan Filing Requirements, FFPC has broken down the ***distribution plant*** into the OEB's investment categories. i.e ***System Access,*** which is defined modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system. ***System Renewal*** which is defined as replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services and ***System Service*** which is defined as modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.

FFPC has provided below, Appendix 2-AB, Capital Expenditure Summary. FFPC has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. FFPC has provided a complete Appendix 2-AA with information about capital expenditures on a project-specific basis following table 2-AB below.

Table 2-AB: Capital Expenditure Summary

CATEGORY	Historical Period (previous plan[1] & actual)														
	2006			2007			2008			2009			2010		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access		-	--		-	--		-	--		-	--		-	--
System Renewal		191	--		130	--		154	--		153	--		166	--
System Service		43	--		43	--		16	--		6	--		80	--
General Plant		100	--		21	--		17	--		118	--		277	--
TOTAL EXPENDITURE	-	335	--	-	194	--	-	187	--	-	278	--	-	523	--
System O&M		$ 248	--		$ 281	--		$ 305	--		$ 325	--		$ 376	--

Table 2-AB Continued: Capital Expenditure Summary

CATEGORY	Historical Period (previous plan[1] & actual)									Forecast Period (planned)				
	2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		3	--		41	--		37	--	422	40	20	45	12
System Renewal		133	--		165	--		150	--	254	419	504	531	361
System Service		1	--		-	--		55	--	49	142	60	58	15
General Plant		9	--		16	--		157	--	97	76	76	33	311
TOTAL EXPENDITURE	-	145	--	-	222	--	-	399	--	820	676	660	667	698
System O&M		$ 365	--		$ 591	--		$ 423	--	$ 675	$ 722	$ 777	$ 839	$ 894

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Table 2-AA: Capital Projects Table

Projects	2006	2007	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Poles, Towers and Fixtures									
2006 Wood Pole Replacement Program	70,702								
2007 Wood Pole Replacement Program		76,776							
2008 Wood Pole Replacement Program			89,464						
2009 Wood Pole Replacement Program				101,896					
2010 Wood Pole Replacement Program					116,198				
2011 Wood Pole Replacement Program						135,340			
2012 Wood Pole Replacement Program							157,180		
2013 Wood Pole Replacement Program								127,975	
14-18-001: Fully Dressed Wood Pole Replacement Program									129,928
Sub-Total	70,702	76,776	89,464	101,896	116,198	135,340	157,180	127,975	129,928
Line Transformers									
14-18-002: Overhead & Pad-Mounted Transformer Replacement Program									95,648
Sub-Total	0	0	0	0	0	0	0	0	95,648
Mandated Service Obligations									
14-18-004: Renewable Enabling Improvements								35,000	50,000
14-14-006: Elimination of Long Term Load Transfers									371,739
Sub-Total	0	0	0	0	0	0	0	35,000	421,739
Other Projects									
Unit #4 & #12: Half Ton & F550 Dump Truck Replacements	90,569								
Unit #5: Digger Derrick Replacement					245,900				
Unit #2: Single Bucket Truck Replacement								120,000	
Unit #6: Cable Reel & Tensioning Trailer Replacement									50,000
Operations Centre Shop Expansion				103,332					
Main Office Emergency Backup Generator					75,466				
Sub-Total	90,569	0	0	103,332	321,366	0	0	120,000	50,000
Miscellaneous	173,322	116,829	97,438	72,557	85,484	9,981	65,094	115,985	123,001
Total	334,594	193,605	186,902	277,785	523,048	145,321	222,274	398,960	820,316
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*							-27,673	-35,000	-50,000
Total	334,594	193,605	186,902	277,785	523,048	145,321	194,602	363,960	770,316

Budget Process:

FFPC has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. FFPC completes ground inspections throughout the year while completing maintenance on the distribution system. In addition, FFPC relies on external contractors to provide a comprehensive analysis of the transformer station infrastructure and to provide maintenance.

In addition, FFPC's Asset Management Plan that is contained in the 2014 - 2018 DS Plan, sets out the necessary distribution system investments to ensure safe, reliable delivery of electricity to our customers.

The budget is prepared annually by management based on the outcomes of the Asset Management and Capital Planning Processes, and is reviewed and approved by the FFPC Board of Directors. The budget is completed for the start of each fiscal year. Once approved, it typically does not change but provides a plan against which actual results may be evaluated. A comparison to each of the year's budget to actual costs is included in this analysis.

The FFPC Board provides direction to Management regarding budget priorities and changes that may result from year-end financial results.

Responsibilities:

- It is the responsibility of the Management of FFPC to co-ordinate the development of the operating budget, capital budget and forecast processes.
- The Management of FFPC is responsible for preparing their respective operating budget, capital budget, and forecasts.

- The CEO is responsible for presenting and recommending the budget to the Board of Directors for approval.

The budget is an important planning tool for FFPC. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of departmental budgets to collectively ensure appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

The annual budget represents the output of detailed work plans based on required activities for the year. FFPC notes that the budget addresses both capital and operating requirements.

Planning - Distribution System Plan

FFPC has included in this Exhibit (Appendix 2A) a consolidated distribution system plan (DS Plan), which was developed in accordance with "Chapter 5 - Consolidated Distribution System Plan Filing Requirements", dated March 28, 2013.

The DS Plan is also submitted as a separate standalone file (PDF).

Capital Projects[1]

The following table provides an overall summary of capital expenditures from 2006 to 2014. This table is taken from Appendix 2-AB of the Chapter 2 Appendices Excel file. Historical "previous plan" data and variances are not provided as a DS Plan has not been previously filed. There were no projects with life-cycle greater than one year.

Table 2.3.1(a) – Summary of Capital Expenditures - Period 2006 to 2014

CATEGORY	Historical Period (previous plan[1] & actual)														
	2006			2007			2008			2009			2010		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access		-	--		-	--		-	--		-	--		-	--
System Renewal		191	--		130	--		154	--		153	--		166	--
System Service		43	--		43	--		16	--		6	--		80	--
General Plant		100	--		21	--		17	--		118	--		277	--
TOTAL EXPENDITURE	-	335	--	-	194	--	-	187	--	-	278	--	-	523	--
System O&M		$ 248	--		$ 281	--		$ 305	--		$ 325	--		$ 376	--

Historical Period (previous plan[1] & actual)										Forecast Period (planned)				
2011			2012			2013			2014	2015	2016	2017	2018
Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
$ '000		%	$ '000		%	$ '000		%	$ '000				
	3	--		41	--		37	--	422	40	20	45	12
	133	--		165	--		150	--	254	419	504	531	361
	1	--		-	--		55	--	49	142	60	58	15
	9	--		16	--		157	--	97	76	76	33	311
-	145	--	-	222	--	-	399	--	820	676	660	667	698
	$ 365	--		$ 591	--		$ 423	--	$ 675	$ 722	$ 777	$ 839	$ 894

Table 2.3.2 below provides capital expenditures on a project-specific basis. This table is taken from Appendix 2-AA of the Chapter 2 Appendices Excel file.

[1] Provincial Sales Tax Impact

As a result of the implementation of HST in the province of Ontario on July 1, 2010, FFPC has considered the reduction in capital expenditures relating to the purchase of products and services due to the increased input tax credit (ITC). Neither the 2013 Bridge Year forecast nor the 2014 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2010.

Table 2.3.1(b) – Capital Projects - Period 2006 to 2014

Projects	2006	2007	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Poles, Towers and Fixtures									
2006 Wood Pole Replacement Program	70,702								
2007 Wood Pole Replacement Program		76,776							
2008 Wood Pole Replacement Program			89,464						
2009 Wood Pole Replacement Program				101,896					
2010 Wood Pole Replacement Program					116,198				
2011 Wood Pole Replacement Program						135,340			
2012 Wood Pole Replacement Program							157,180		
2013 Wood Pole Replacement Program								127,975	
14-18-001: Fully Dressed Wood Pole Replacement Program									129,928
Sub-Total	70,702	76,776	89,464	101,896	116,198	135,340	157,180	127,975	129,928
Line Transformers									
14-18-002: Overhead & Pad-Mounted Transformer Replacement Program									95,648
Sub-Total	0	0	0	0	0	0	0	0	95,648
Mandated Service Obligations									
14-18-004: Renewable Enabling Improvements								35,000	50,000
14-14-006: Elimination of Long Term Load Transfers									371,739
Sub-Total	0	0	0	0	0	0	0	35,000	421,739
Other Projects									
Unit #4 & #12: Half Ton & F550 Dump Truck Replacements	90,569								
Unit #5: Digger Derrick Replacement					245,900				
Unit #2: Single Bucket Truck Replacement								120,000	
Unit #6: Cable Reel & Tensioning Trailer Replacement									50,000
Operations Centre Shop Expansion				103,332					
Main Office Emergency Backup Generator					75,466				
Sub-Total	90,569	0	0	103,332	321,366	0	0	120,000	50,000
Miscellaneous	173,322	116,829	97,438	72,557	85,484	9,981	37,422	115,985	123,001
Total	334,594	193,605	186,902	277,785	523,048	145,321	194,602	398,960	820,316
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*							-27,673	-35,000	-50,000
Total	334,594	193,605	186,902	277,785	523,048	145,321	166,930	363,960	770,316

Variance Analysis of Actual Capital Expenditures versus Board

Section 2.5.2.2 "Required Information" of the Boards filing requirements asks distributors to provide written explanation of variances, between actual and Board approved capital expenditures. FFPC's last Board-approved cost of service application was conducted in 2006, at which time to the best of FFPC's knowledge, the Board did not provide distributors with approved capital expenditure amounts. As such, FFPC is unable to perform the "Actuals versus Board Approved Variance Analysis".

Non-Distribution Activities:

FFPC did not incur any capital expenditures related to non-distribution activities.

Asset Management Plan:

Over the last few years, FFPC has worked extensively on formalizing its asset management process and on preparing its first formal asset management plan. FFPC and its predecessors had been managing distribution assets in the Town of Fort Frances since the early 1900's, long before the electrification of the Province as a whole occurred. Although FFPC has extensive experience managing assets, historically a formal process or plan was never documented. Section 5.3 of the DS Plan details FFPC's approach to the management of its assets. A flow chart of FFPC's Asset Management Process, as well as a step-by-step "Recipe" format summary, are also included in the section.

FFPC is very pleased with the OEB's impetus for distributors to develop DS Plans. FFPC believes that its newly developed asset management and capital planning processes, which are at the heart of the DS Plan, will bring tremendous future value to its customers. The initiative has allowed FFPC to transition from reactive short term planning and historic budgeting practices, to proactive long range planning and asset condition based budgeting. FFPC is confident that its DS Plan will accomplish the Board's five objectives of "Good Distributor Planning" (Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance).

Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

FFPC has incurred and plans to incur further eligible investments as described in section 79.1 of the OEB Act and Reg.330/09 under the Act. Details regarding FFPC's Renewable Enabling Improvements to its Greater than 50 kV Transformer Station are discussed in Section 5.4.3 of the 2014 to 2018 DS Plan, has been attached as Appendix 2A.

FFPC has assumed a direct the benefit of 6% associated with renewable enabling improvement investments, as well as 17% for any renewable generation connection investments, as per the Board's July 17, 2013 released Filing Requirements for distributors. FFPC believes the standard direct benefits to be reflective of FFPC's circumstances, and as such FFPC is not planning to pursue the option to undertake its own "detailed" direct benefits assessment based on the criteria set out in the Direct Benefits Report.

FFPC notes that its eligible renewable enabling improvements span over a seven year horizon, as FFPC's last COS of Rate Rebasing was conducted in 2006. As such, FFPC has not been able to formally dispose of its renewable enabling improvement expenses incurred in 2012 and 2013.

The following tables reflect Appendices 2-FA and 2-FB from the Chapter 2 Appendices, identifying all eligible investments. The appendices provide information on all costs (capital and OM&A), and the shares of total costs to be recovered from all Ontario ratepayers (net of direct benefits) and FFPC's ratepayers. The appendices also provide a revenue requirement calculation for the asset costs to be recovered annually through Regulation 330/09 Provincial Rate Protection. FFPC does not have any REG specific expansion projects, and as such Appendices 2-FC has been omitted

Appendix 2-FA
Renewable Generation Connection Investment Summary (over the rate setting period)

REI Investments (Direct Benefit at 6%)	2014	2015	2016	2017	2018
Project 1					
Transformer T1 Protection					
Capital Costs	$32,772	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Transformer T2 Protection					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Station Data Acquisition System					
Capital Costs	$0	$20,000	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$2,000	$0	$0	$0
Project 4					
Station Communication Network Installation					
Capital Costs	$0	$20,000	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$2,000	$0	$0	$0
Project 5					
Station OCB Protection					
Capital Costs	$0	$0	$20,000	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$2,000	$0	$0
Project 6					
Station Supervisory Control					
Capital Costs	$0	$0	$0	$45,000	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$3,500	$0
Project 7					
Station DC System Monitoring & Remote Annunciation					
Capital Costs	$0	$0	$0	$0	$12,000
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$1,200
Total Capital Costs	**$ 32,772**	**$ 40,000**	**$ 20,000**	**$ 45,000**	**$ 12,000**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ 4,000**	**$ 2,000**	**$ 3,500**	**$ 1,200**

Part B

Expansion Investments (Direct Benefit at 17%)	2014	2015	2016	2017	2018
Project 1					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: Expansion Connection Project					

Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount:
Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentag
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014 Test Year			2015			2016			2017			2018		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ 16,204	$ 972	$ 15,232	$ 51,822	$ 3,109	$ 48,712	$ 80,315	$ 4,819	$ 75,497	$ 110,615	$ 6,637	$ 103,978	$ 136,237	$ 8,174	$ 128,063
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$4,000	$ 4,000		$2,000	$ 2,000		$3,500	$ 3,500		$1,200	$ 1,200	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13%		$ -	$ -		$ 520	$ -		$ 260	$ -		$ 455	$ -		$ 156	$ -
Rate Base			$ 972	$ 15,232		$ 3,629	$ 48,712		$ 5,079	$ 75,497		$ 7,092	$ 103,978		$ 8,330	$ 128,063
Deemed ST Debt	4%		$ 39	$ 609		$ 145	$ 1,948		$ 203	$ 3,020		$ 284	$ 4,159		$ 333	$ 5,123
Deemed LT Debt	56%		$ 544	$ 8,530		$ 2,032	$ 27,279		$ 2,844	$ 42,278		$ 3,971	$ 58,228		$ 4,665	$ 71,715
Deemed Equity	40%		$ 389	$ 6,093		$ 1,452	$ 19,485		$ 2,032	$ 30,199		$ 2,837	$ 41,591		$ 3,332	$ 51,225
ST Interest	2.11%		$ 1	$ 13		$ 3	$ 41		$ 4	$ 64		$ 6	$ 88		$ 7	$ 108
LT Interest	4.88%		$ 27	$ 416		$ 99	$ 1,331		$ 139	$ 2,063		$ 194	$ 2,842		$ 228	$ 3,500
ROE	0.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ 27	$ 429		$ 102	$ 1,372		$ 143	$ 2,127		$ 200	$ 2,929		$ 235	$ 3,608
OM&A			$ -	$ -		$ 4,000	$ -		$ 2,000	$ -		$ 3,500	$ -		$ 1,200	$ -
Amortization		$ 364	$ 22	$ 342	$ 1,173	$ 70	$ 1,102	$ 1,839	$ 110	$ 1,729	$ 2,562	$ 154	$ 2,408	$ 3,195	$ 192	$ 3,003
Grossed-up PILs			$ -	-$ 48		$ -	-$ 19		$ -	$ 101		$ -	$ 229		$ -	$ 341
Revenue Requirement			$ 49	$ 723		$ 4,173	$ 2,456		$ 2,253	$ 3,956		$ 3,853	$ 5,566		$ 1,626	$ 6,952
Provincial Rate Protection				$ 723			$ 2,456			$ 3,956			$ 5,566			$ 6,952
Monthly Amount Paid by IESO				$ 60			$ 205			$ 330			$ 464			$ 579

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2014 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2014		2015		2016		2017		2018	
	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Amortization (6% DB and 94% P)	$ 22	$ 342	$ 70	$ 1,102	$ 110	$ 1,729		$ 154	$ 2,408		$ 192	$ 3,003
CCA (6% DB and 94% P)	-$ 39	-$ 616	-$ 77	-$ 1,208	-$ 74	-$ 1,159		-$ 71	-$ 1,113		-$ 68	-$ 1,068
Taxable income	-$ 17	-$ 274	-$ 7	-$ 105	$ 36	$ 570		$ 83	$ 1,295		$ 124	$ 1,935
Tax Rate (to be entered)	0.00%	15.00%	0.00%	15.00%	0.00%	15.00%		0.00%	15.00%		0.00%	15.00%
Income Taxes Payable	$ -	-$ 41.07	$ -	-$ 15.79	$ -	$ 85.46		$ -	$ 194.25		$ -	$ 290.23
Gross Up												
Income Taxes Payable	$ -	-$ 48.32	$ -	-$ 18.57	$ -	$ 100.54		$ -	$ 228.53		$ -	$ 341.44
Grossed Up PILs	$ -	-$ 48	$ -	-$ 19	$ -	$ 101		$ -	$ 229		$ -	$ 341

Net Fixed Assets	2014	2015	2016	2017	2018
Enter applicable amortization in years: 45					
Opening Gross Fixed Assets		$ 32,772	$ 72,772	$ 92,772	$ 137,772
Gross Capital Additions	$ 32,772	$ 40,000	$ 20,000	$ 45,000	$ 12,000
Closing Gross Fixed Assets	$ 32,772	$ 72,772	$ 92,772	$ 137,772	$ 149,772
Opening Accumulated Amortization		$ 364	$ 1,537	$ 3,376	$ 5,938
Current Year Amortization (before additions)		$ 728	$ 1,617	$ 2,062	$ 3,062
Additions (half year)	$ 364	$ 444	$ 222	$ 500	$ 133
Closing Accumulated Amortization	$ 364	$ 1,537	$ 3,376	$ 5,938	$ 9,133
Opening Net Fixed Assets	$ -	$ 32,408	$ 71,235	$ 89,396	$ 131,834
Closing Net Fixed Assets	$ 32,408	$ 71,235	$ 89,396	$ 131,834	$ 140,639
Average Net Fixed Assets	$ 16,204	$ 51,822	$ 80,315	$ 110,615	$ 136,237

UCC for PILs Calculation

	2014	2015	2016	2017	2018
Opening UCC		$ 32,117	$ 30,832	$ 29,599	$ 28,415
Capital Additions (from Appendix 2-FA)	$ 32,772	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ 32,772	$ 32,117	$ 30,832	$ 29,599	$ 28,415
Half Year Rule (1/2 Additions - Disposals)	$ 16,386	$ -	$ -	$ -	$ -
Reduced UCC	$ 16,386	$ 32,117	$ 30,832	$ 29,599	$ 28,415
CCA Rate Class (to be entered) 1	1	1	1	1	1
CCA Rate (to be entered) 4%	4%	4%	4%	4%	4%
CCA	$ 655	$ 1,285	$ 1,233	$ 1,184	$ 1,137
Closing UCC	$ 32,117	$ 30,832	$ 29,599	$ 28,415	$ 27,278

Addition of ICM Assets to Rate Base

FFPC does not have an approved ICM, and as such is not filing a schedule of the ICM capital asset amounts to have them incorporated into rate base.

Capitalization Policy

FFPC has historically applied the following general capitalization policies and principles based on Canadian Generally Accepted Accounting Principles ("CGAAP"), as well as guidelines set out by the Ontario Energy Board, where applicable. As stated in Exhibit 1, Tab 5, Schedule 9, FFPC has elected to defer implementation of modified International Financial Reporting Standards (IFRS) until January 1, 2015.

The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit greater than one year will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset will be capitalized.
- With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.

Guidelines for Capitalization

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A "betterment" is a cost which enhances the service potential of a capital asset and is therefore capitalized. A "betterment" includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

CAPITAL ASSET COST

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost.

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

Amortization

In 2013, FFPC changed its amortization policy under CGAAP, to align it with its newly developed asset management process that was developed based on the useful life of assets set out in the Kinectrics Asset Depreciation Study (Kinectrics Report). Table 1.5.11

included in *Exhibit 1, Tab 5, Schedule 9 contains the useful lives by Uniform System of Account, compared to the current useful lives used under CGAAP.

For the purposes of this rate application, FFPC used the half year rule for calculating depreciation expense for the 2014 Test Year. Details of FFPC's depreciation by account number are provided in the Fixed Asset Continuity Schedules as set out in Exhibit 2, Tab 2, Schedule 4.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. The units are required to be on hand to ensure continued customer supply, in the event of transformer or meter failures.

Capitalization of Burdens

As stated in Exhibit 1, Tab 5, Schedule 9, as a rate-regulated entity, FFPC has elected to defer implementation of modified International Financial Reporting Standards (IFRS) until January 1, 2015. Historically, FFPC did not capitalize administrative burdens.

Service Quality and Reliability Indices

FFPC tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding loss of supply related incidents. Detailed System Reliability and Performance, as well as Service Quality assessments are provided in Section 5.2.3.6 of the DS Plan. The following summary tables illustrate FFPC reported results over the past seven years.

Service Reliability Indices Including Loss of Supply

	2006	2007	2008	2009	2010	2011	2012
SAIDI = Annual	0.151	0.300	3.770	6.633	0.597	0.090	0.302
SAIFI = Annual	0.242	0.310	1.770	2.401	0.310	0.210	0.296
CAIDI = Annual	0.624	0.950	2.130	2.763	1.924	0.430	1.021

Service Reliability Indices Adjusted for Loss of Supply

	2006	2007	2008	2009	2010	2011	2012
SAIDI = Annual	0.151	0.300	0.987	0.384	0.597	0.090	0.302
SAIFI = Annual	0.242	0.310	0.791	0.401	0.310	0.210	0.296
CAIDI = Annual	0.624	0.950	1.248	0.957	1.924	0.430	1.021

The following table illustrates FFPC's five year Service Reliability Indicators as per Appendix 2-G of the Board's Chapter 2 Appendices.

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
SAIDI	3.770	6.633	0.597	0.090	0.302	0.987	0.384	0.597	0.090	0.302
SAIFI	1.770	2.401	0.310	0.210	0.296	0.791	0.401	0.310	0.210	0.296

	5 Year Historical Average			
SAIDI		2.278		0.472
SAIFI		0.997		0.402

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

FFPC is committed to maintaining the reliability of its distribution system to meet regulatory requirements, as well as customer expectations. In order to maintain current performance levels, which meet regulatory and customer expectations, FFPC will need to continue to invest in capital and maintenance programs. In particular, the capital programs noted Section 5.4.2 of the DS Plan, with a primary driver of End-of-Life or Risk of Failure, are necessary to sustain the overall health and reliability of the distribution system. Renewal of these assets removes the risk to reliability and safety that would otherwise be unacceptable.

In addition to the reliability indices, FFPC also measures service quality indicators ("SQIs"). Table 2.4.3 below summarizes FFPC's reported SQIs for the historical years 2005, 2006, 2007, 2008, 2009, 2010, 2011 and 2012. In 2011, the SQI's were replaced by the Electricity Service Quality Requirements (ESQRs).

Table 2.4.3 - Reported Service Quality Indicators (SQIs)

Service Quality Requirements	2005	2006	2007	2008	2009	2010	2011	2012
Low Voltage Connections (OEB Min. Standard: 90%)	N/A	100	100	100	100	100	100	100
High Voltage Connections (OEB Min. Standard: 90%)	N/A	100	0	100	100	100	100	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	N/A	100	100	100	97.4	94	94.1	93.6
Appointments Met (OEB Min. Standard: 90%)	N/A	100	100	100	100	100	100	100
Written Response to Enquiries (OEB Min. Standard: 80%)	N/A	0	100	100	100	100	98	100
Emergency Urban Response (OEB Min. Standard: 80%)	N/A	100	100	100	100	100	100	100
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	N/A	N/A	N/A	N/A	3.1	2.8	5.1	2.2
Appointments Scheduling (OEB Min. Standard: 90%)	N/A	N/A	N/A	N/A	100	100	100	100
Rescheduling a Missed Appointment (OEB Standard: 100%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Reconnection Performance Standard (OEB Min. Standard: 85%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	100

ALLOWANCE FOR WORKING CAPITAL:

In accordance with the Ontario Energy Board's letter dated April 12, 2013 "RE: *Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital*", FFPC has incorporated the default value of 13% as the Allowance Approach for Working Capital on the following basis:

- The 13% Allowance Approach is calculated to be 13% of the sum of Cost of Power and controllable expenses (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

- The commodity price estimate used to calculate the Cost of Power is based on the split between RPP and non-RPP customers on actual data. The calculation reflects the most recent Uniform Transmission Rates approved by the Board (EB-2012-0031), issued on December 20, 2012 and effective January 1, 2013. In the event new Uniform Transmission Rates are approved by the Board before finalization of this Rate Application, the commodity price estimate will be recalculated to reflect those new rates.

Overview and Calculation by Account:

FFPC's working capital allowance is forecast to be $1,124,571 for 2014, based on the methodology outlined above in accordance with the April 12, 2012 letter from the Ontario Energy Board. Table 2.4.1 below sets out FFPC's working capital allowance calculation.

Table 2.4.1: Working Capital Allowance Calculation 2014 (CGAAP)

Description	2014 Test Year
Operations	$ 371,000
Maintenance	$ 6,992,896
Billing and Collecting	$ 268,000
Community Relations	$ 37,150
Administrative and General	$ 664,500
Taxes Other Than Income Taxes	$ 13,000
Total Eligible Distribution Expenses	**$ 1,657,650**
Power Supply Expenses	$ 6,992,896
Total Working Capital Expenses	**$ 8,650,546**
Working Capital Allowance @ 13%	**$ 1,124,571**

As indicated in Exhibit 2, Schedule 1, Table 2.1.1(b) provides a summary of Working Capital comparison for the 2006 OEB Approved; 2006, 2007, 2008, 2009, 2010, 2011 and 2012 Actual years; and 2013 Bridge Year/2014 Test Year under CGAAP. This Table is reproduced here for reference to Table 2.4.1 above.

Table 2.1.1(b): Summary of Working Capital 2010-2014

Description	2006 OEB Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$142,165	$154,931	$167,586	$161,730	$194,356	$192,399	$195,697	$213,851	$209,500	$371,000
Maintenance	$106,651	$92,874	$113,833	$142,860	$130,396	$183,394	$169,076	$377,219	$213,000	$304,000
Billing and Collecting	$144,547	$237,343	$235,870	$254,460	$266,345	$265,204	$213,984	$255,946	$235,500	$268,000
Community Relations	$4,712	$62,599	$35,457	$21,187	$14,905	$8,805	$6,024	$5,978	$4,750	$37,150
Administrative and General	$603,271	$577,417	$612,906	$686,964	$710,557	$675,883	$717,211	$751,977	$750,500	$664,500
Taxes Other Than Income Taxes	$0	$14,525	$14,652	$14,638	$14,092	$12,775	$12,484	$12,264	$13,000	$13,000
Total Eligible Distribution Expenses	**$1,001,346**	**$1,139,689**	**$1,180,304**	**$1,281,839**	**$1,330,651**	**$1,338,460**	**$1,314,476**	**$1,617,235**	**$1,426,250**	**$1,657,650**
Power Supply Expenses	$5,416,974	$5,805,198	$6,159,730	$5,889,409	$6,308,863	$5,722,105	$6,187,827	$7,285,062	$6,868,831	$6,992,896
Total Working Capital Expenses	**$6,418,320**	**$6,944,887**	**$7,340,034**	**$7,171,248**	**$7,639,514**	**$7,060,565**	**$7,502,303**	**$8,902,297**	**$8,295,081**	**$8,650,546**
OEB Prescribed % Working Capital Allowance	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*13%*	*13%*
Working Capital Allowance	**$962,748**	**$1,041,733**	**$1,101,005**	**$1,075,687**	**$1,145,927**	**$1,059,085**	**$1,125,346**	**$1,335,345**	**$1,078,361**	**$1,124,571**

Cost of Power

FFPC has calculated cost of power for the 2013 Bridge Year and 2014 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Report – May 1, 2013 to April 30, 2014, issued April 5, 2013. FFPC will update the electricity prices should the OEB publish a revised Regulated Price Plan Report prior to a Decision.

The Cost of Power calculations for the 2013 Bridge Year and a cost of power summary are provided in the following Table 2.4.2 and Table 2.4.3 respectively. The cost of power calculations for the 2014 Test Year and a cost of power summary are provided in the following Table 2.4.4 and Table 2.4.5 respectively.

Table 2.4.2 Cost of Power Forecast Calculation – 2013 Bridge Year

2013 Load Foreacst	kWh	kW	2012 %RPP
Residential	37,551,665		98%
General Service< 50 kW	14,200,992		98%
General Service> 50 kW	25,160,587	64,192	13%
Streetlights	765,211	2,199	0%
Unmetered Loads	55,151		100%
TOTAL	**77,733,606**	**66,391**	

Table 2.4.2 Cost of Power Forecast Calculation – 2013 Bridge Year (cont'd)

Electricity - Commodity RPP Class per Load Forecast RPP	2013	2013 Loss	2013	*	
Residential	36,800,632	1.0406	38,294,738	$0.08760	$3,354,619
General Service< 50 kW	13,916,972	1.0406	14,482,001	$0.08760	$1,268,623
General Service> 50 kW	3,270,876	1.0406	3,403,674	$0.08760	$298,162
Streetlights	0	1.0406	0	$0.08760	$0
Unmetered Loads	55,151	1.0406	57,390	$0.08760	$5,027
TOTAL	**54,043,632**		**56,237,803**		**$4,926,432**

Electricity - Commodity Non-RPP Class per Load Forecast	2013	2013 Loss	2013		
Residential	751,033	1.0406	781,525	$0.08545	$66,781
General Service< 50 kW	284,020	1.0406	295,551	$0.08545	$25,255
General Service> 50 kW	21,889,710	1.0406	22,778,433	$0.08545	$1,946,417
Streetlights	765,211	1.0406	796,279	$0.08545	$68,042
Unmetered Loads	0	1.0406	0	$0.08545	$0
TOTAL	**23,689,975**		**24,651,788**		**$2,106,495**

Transmission - Network Class per Load Forecast		Volume Metric	2013		
Residential		kWh	39,076,263	$0.0066	$257,903
General Service< 50 kW		kWh	14,777,552	$0.0060	$88,665
General Service> 50 kW		kW	64,192	$2.4488	$157,193
Streetlights		kW	2,199	$1.8469	$4,061
Unmetered Loads		kWh	57,390	$0.0060	$344
TOTAL					**$508,168**

Transmission - Connection Class per Load Forecast		Volume Metric	2013		
Residential		kWh	39,076,263	$0.0016	$62,522
General Service< 50 kW		kWh	14,777,552	$0.0014	$20,689
General Service> 50 kW		kW	64,192	$0.5770	$37,039
Streetlights		kW	2,199	$0.4461	$981
Unmetered Loads		kWh	57,390	$0.0014	$80
TOTAL				`	**$121,311**

Wholesale Market Service Class per Load Forecast			2013		
Residential			39,076,263	$0.0044	$171,936
General Service< 50 kW			14,777,552	$0.0044	$65,021
General Service> 50 kW			26,182,107	$0.0044	$115,201
Streetlights			796,279	$0.0044	$3,504
Unmetered Loads			57,390	$0.0044	$253
TOTAL			**80,889,591**		**$355,914**

Rural Rate Assistance Class per Load Forecast			2013		
Residential			39,076,263	$0.0012	$46,892
General Service< 50 kW			14,777,552	$0.0012	$17,733
General Service> 50 kW			26,182,107	$0.0012	$31,419
Streetlights			796,279	$0.0012	$956
Unmetered Loads			57,390	$0.0012	$69
TOTAL			**80,889,591**		**$97,068**

Table 2.4.3 Cost of Power Summary – 2013 Bridge Year

Cost of Power	2013
4705-Power Purchased	$7,032,927
4708-Charges-WMS	$355,914
4714-Charges-NW	$508,168
4716-Charges-CN	$121,311
4730-Rural Rate Assistance	$97,068
4750-Low Voltage	
TOTAL	**8,115,387**

Table 2.4.4 Cost of Power Forecast Calculation – 2014 Test Year

2014 Load Foreacst	kWh	kW	2012 %RPP
Residential	37,751,518		98%
General Service< 50 kW	13,617,679		98%
General Service> 50 kW	26,376,324	67,294	13%
Streetlights	366,947	1,055	0%
Unmetered Loads	48,552		100%
TOTAL	**78,161,019**	**68,348**	

Electricity - Commodity RPP Class per Load Forecast RPP	2014	2014 Loss	2014		
Residential	36,996,487	1.0406	38,498,545	$0.08395	$3,231,953
General Service< 50 kW	13,345,325	1.0406	13,887,146	$0.08395	$1,165,826
General Service> 50 kW	3,428,922	1.0406	3,568,136	$0.08395	$299,545
Streetlights	0	1.0406	0	$0.08395	$0
Unmetered Loads	48,552	1.0406	50,523	$0.08395	$4,241
TOTAL	**53,819,287**		**56,004,350**		**$4,701,565**

Electricity - Commodity Non-RPP Class per Load Forecast	2014	2014 Loss	2014		
Residential	755,030	1.0406	785,685	$0.08545	$67,137
General Service< 50 kW	272,354	1.0406	283,411	$0.08545	$24,217
General Service> 50 kW	22,947,402	1.0406	23,879,066	$0.08545	$2,040,466
Streetlights	366,947	1.0406	381,845	$0.08545	$32,629
Unmetered Loads	0	1.0406	0	$0.08545	$0
TOTAL	**24,341,732**		**25,330,006**		**$2,164,449**

Table 2.4.4 Cost of Power Forecast Calculation – 2014 Test Year (cont'd)

Transmission - Network Class per Load Forecast		Volume Metric	2014		
Residential		kWh	39,284,229	$0.0067	$263,204
General Service< 50 kW		kWh	14,170,557	$0.0061	$86,440
General Service> 50 kW		kW	67,294	$2.4949	$167,891
Streetlights		kW	1,055	$1.8817	$1,984
Unmetered Loads		kWh	50,523	$0.0061	$308
TOTAL					**$519,828**

Transmission - Connection Class per Load Forecast		Volume Metric	2014		
Residential		kWh	39,284,229	$0.0015	$58,926
General Service< 50 kW		kWh	14,170,557	$0.0013	$18,422
General Service> 50 kW		kW	67,294	$0.5516	$37,119
Streetlights		kW	1,055	$0.4265	$450
Unmetered Loads		kWh	50,523	$0.0013	$66
TOTAL					**$114,983**

Wholesale Market Service Class per Load Forecast			2014		
Residential			39,284,229	$0.0044	$172,851
General Service< 50 kW			14,170,557	$0.0044	$62,350
General Service> 50 kW			27,447,202	$0.0044	$120,768
Streetlights			381,845	$0.0044	$1,680
Unmetered Loads			50,523	$0.0044	$222
TOTAL			**81,334,357**		**$357,871**

Rural Rate Assistance Class per Load Forecast			2014		
Residential			39,284,229	$0.0012	$47,141
General Service< 50 kW			14,170,557	$0.0012	$17,005
General Service> 50 kW			27,447,202	$0.0012	$32,937
Streetlights			381,845	$0.0012	$458
Unmetered Loads			50,523	$0.0012	$61
TOTAL			**81,334,357**		**$97,601**

Table 2.4.5 Cost of Power Summary – 2014 Test Year

Cost of Power	2014
4705-Power Purchased	$6,866,014
4708-Charges-WMS	$357,871
4714-Charges-NW	$519,828
4716-Charges-CN	$114,983
4730-Rural Rate Assistance	$97,601
4750-Low Voltage	
TOTAL	**7,956,298**

Treatment of Stranded Assets Related to Smart Meter Deployment

Summary

The Board's Guideline: Smart Meter Funding and Cost Recovery (G-2008-0002) provided two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters: (1) leave them in rate base (i.e. Account 1860); or (2) record them in "Sub-account Stranded Meter Costs" of Account 1555. FFPC adopted Option 1 and left the stranded meters in Account #1860.

Accounting guidance in the December 2010 Accounting Procedures Handbook FAQs (Q and A #15) provided information as to how the COS rate-setting process may be used to address the recovery by distributors of costs associated with stranded meters On December 15, 2011, the Board issued Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition, which provides the most current guidance on the treatment for recovery of costs for stranded meters replaced by smart meters.

FFPC is filing as part of this 2014 application a proposed treatment for the recovery of stranded meters that FFPC believes is in conformity with the approach taken by the Board in the guidance documents referred to above. The details of FFPC's filing including are set out in Exhibit 9, Tab 3, Schedule 3.

Fort Frances Power Corporation

APPENDIX 2A

FFPC Distribution System Plan for the Period 2014 to 2018



Fort Frances Power Corporation

Distribution System Plan

For the Period

2014 to 2018

Filed with FFPC's 2014 Cost of Service Rate Application

Case Number EB-2013-0130

Submitted December 20, 2013

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5.2 FFPC Distribution System Plan

FFPC has organized its Distribution System Plan (DS Plan) according to the suggested format contained within the March 28, 2013 "Chapter 5 Consolidated Distribution System Plan Filing Requirements Guide". Considerable additional subsections have been added to expand on relevant topics of discussion, as well as for ease of reference. This is FFPC's first DS Plan, and as such there are no available comparisons to any previously filed DS Plans.

5.2.1 Distribution System Plan Overview

5.2.1.1 The History of our Community and Customers We Serve

The settlement now known as the town of "Fort Frances", was the first European settlement west of Lake Superior. The settlement was established by French Canadian Pierre Gaultier de Varennes et de La Vérendrye, first commander of the western district. In 1731 he built Fort St. Pierre near the settlement, as support for the fur trade with native peoples.

In 1817, following the War of 1812 and redefinition of borders between Canada and the United States, the Hudson's Bay Company (HBC) also built a fort here. Officials named the subsequent settlement after Lady Frances Simpson, wife of then Hudson's Bay Company Governor George Simpson, who visited the fort many times. In 1903 the settlement was incorporated as "the Corporation of the Town of Fort Frances", in honour of Lady Frances Simpson.

The main employer in Fort Frances up until recently, was a pulp and paper mill which was established in the early 1900s by Edward Wellington Backus. The mill is now owned by Resolute Forest Products, and currently employs approximately 250 employees. At its peak operation, the mill employed just over 1,000 employees.

Fort Frances is a town in, and the seat of, Rainy River District in Northwestern Ontario, Canada. The population as of the 2011 census was 7,952. Fort Frances is a popular fishing destination and it hosts the annual Fort Frances Canadian Bass Championship. Located on the international border with the United States where Rainy Lake narrows to become Rainy River, it is connected to International Falls, Minnesota, by the Fort Frances-International Falls International Bridge. The town is currently the third largest community of Northwestern Ontario, after Thunder Bay and Kenora. Fort Frances offers many shopping and dining outlets for local and outlying residents, as well to many tourists.

5.2.1.2 Introduction to the Fort Frances Power Corporation

The Fort Frances Power Corporation (FFPC) is a municipally owned local distribution company serving the residents and customers of the town of Fort Frances. FFPC is currently licensed to distribute electricity within the confines of the municipal boundaries of town of Fort Frances. FFPC is one of the last local distribution

companies in Ontario to operate under the principle of "Power at Cost", which was the philosophy under which the province was electrified. As such, FFPC operates under a rate-minimization model with a target Return-on-Equity of zero percent (0%).

FFPC's distribution system was meticulously designed and constructed accordingly, during a complete system wide voltage conversion project that lasted from the mid 1970's until the mid 1980's. During this time, the entire distribution system was converted from a 2400 Volt system to a 7200 Volt system. Essentially all of FFPC's distribution assets were replaced as a result of this initiative. To this day, FFPC owns and operates a very well built, reliable, safe and efficient electrical distribution system. Due to the entire system being rebuilt over a relatively short timeframe, FFPC has had the luxury of operating in a "maintenance mode" for the last few decades. Over the 2014 to 2018 planning horizon, FFPC is transitioning out of its maintenance mode into a capital rebuild mode. The transition is driven by the results of the newly implemented asset management and capital planning processes, which have given FFPC improved oversight and understanding of the state of its distribution system.

In 2008, FFPC contracted EnerSpectrum Group to perform a distribution system analysis for loss optimization. The analysis reported the following conclusions:

> "The results from this analysis indicate marginal if not negative implications of any attempts to rebalance the system by changing individual load phase connections. This is a reflection of the quality of the work undertaken by operations staff over several years to sustain a well balanced distribution network."
>
> "Although additional options for loss reduction were considered briefly (eg. Increasing conductor size), the costs would greatly outweigh any benefits that would accrue, again representation of a well designed, constructed and maintained system."
>
> Fort Frances Power Corporation, System Loss Optimization, EnerSpectrum Group, August 2008

It is also important to note that FFPC also owns and operates a greater than 50 KV transformer station called "Fort Frances MTS" (FFMTS), which steps down the incoming 115 kV transmission supply to 7.2 kV, which is suitable for distribution. The station was also built to coincide with the voltage conversion initiative and as such it was built in two phases during the 1970's. FFMTS replaced five individual transformer stations that were located throughout Fort Frances. All five stations have been decommissioned and returned to natural green spaces. From a replacement cost perspective, the transformer station "Fort Frances MTS" (High Voltage Asset) represents approximately 20% of FFPC's entire asset base.

5.2.1.3 Planning Process

FFPC operates under a rate minimization philosophy with the objective of balancing necessary distribution system maintenance and reinvestment, with providing customers with a safe and reliable supply of electricity at the lowest possible rates. FFPC has taken a "just-in-time" asset replacement approach, under which assets will

be replaced on a proactive manner, as they approach their high probability of failure zone of their lifecycle, as established by FFPC's asset management process. FFPC's strategy is to replace end-of-life assets under planned and coordinated circumstances, as opposed to under emergency or afterhours circumstances which add unnecessary risk and expense.

Over the last eight years, FFPC has exerted significant effort in quantifying and characterizing its property, plant and equipment with the assistance of a Geographic Information System (GIS). FFPC now has a very detailed asset register that contains both quantitative data such as the age of individual assets, as well as key qualitative data, such as inspection and condition testing results. This wealth of data has enabled FFPC to project when individual assets are expected to reach the end of their useful service life, at which time the assets have a high probability of failure.

The GIS system has become one of FFPC's most relied upon day-to-day core business systems. The tool has allowed FFPC to gain improved oversight of its entire asset base at the individual asset level, thereby enabling data driven decision making for improved long range planning. FFPC's DS Plan is built on the foundation of data contained within the GIS tool, and as such the DS Plan has been built based on a "bottom up" approach. This approach has allowed FFPC to transition from planning projects in general areas such as streets or blocks, to pin-pointing individual assets throughout the distribution system. As such, FFPC's budgets are now largely driven by the needs of individual assets, their lifecycle and replacement cost.

FFPC has also incorporated the OEB's principles for good planning with a focus of achieving performance outcomes as per the renewed regulatory framework for electricity. As such, FFPC is committed to Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. Throughout this submission, FFPC aims to demonstrate the functionality of its asset management and capital planning processes, that underpin delivering value to customers.

FFPC's planning objectives are to deliver on the following performance outcomes over the 2014 to 2018 planning horizon and beyond:

- Customer Focus
    - To provide services in alignment with customer preferences and needs
- Operational Effectiveness
    - Keep pace with distribution system deterioration through reinvestments as determined by FFPC's asset management process
    - Minimize future rate instability by smoothing the age profile of distribution asset classes/groups
    - Support the achievement of customer and regulatory reliability & service quality expectations
    - Support the achievement of performance measures contained in the OEB's Distributor Scorecard
    - Support future objectives of Regional Planning (unknown at this time)
- Support Public Policy Objectives:
    - Support the connection of renewable generation to the distribution system, as well as directly to the transformer station
    - Support the deployment of a smart grid and the achievement of associated objectives

- Support the achievement of conservation and demand management targets
- Support the mandated elimination of Long Term Load Transfer Arrangements

- Financial Performance:
  - To ensure that financial viability is maintained in consideration of operating under a zero-percent rate-of-return on equity

5.2.1.4 Key Elements of the DS Plan

FFPC utilized its newly developed Asset Management and Capital Planning Processes to develop its 2014 to 2018 Capital Investment Plan. Since 2005, FFPC has dedicated tremendous resources towards the development of a Geographical Information System (GIS). The system has been invaluable for building the foundation of this data driven DS Plan. The system was heavily relied upon for the lifecycle analysis of essentially all assets owned, including General Plant assets. Lifecycle sustaining capital reinvestments account for $2,775,966 or 78.8% of the total $3,522,205 capital investment need identified for the 2014 to 2018 planning period. FFPC conducted detailed asset category specific lifecycle needs analyses to determine expenditure requirements. The detailed analysis summaries are included as part of the DS Plan throughout Section 5.3. It is very important to note that FFPC's entire distribution system, including its greater than 50 kV transformer station, was rebuilt from the mid 1970s to mid 1980s, and as such FFPC operated in a "maintenance mode" for several decades, with relatively low requirements for capital reinvestments. Many assets owned are now aging and will be approaching the end of their useful service life over the course of the 2014 to 2018 planning period. The oncoming wave of aging assets has prompted FFPC to transition from its maintenance mode to a capital rebuild mode, to keep pace with the disproportionate high volume of assets posing high risks of failure.

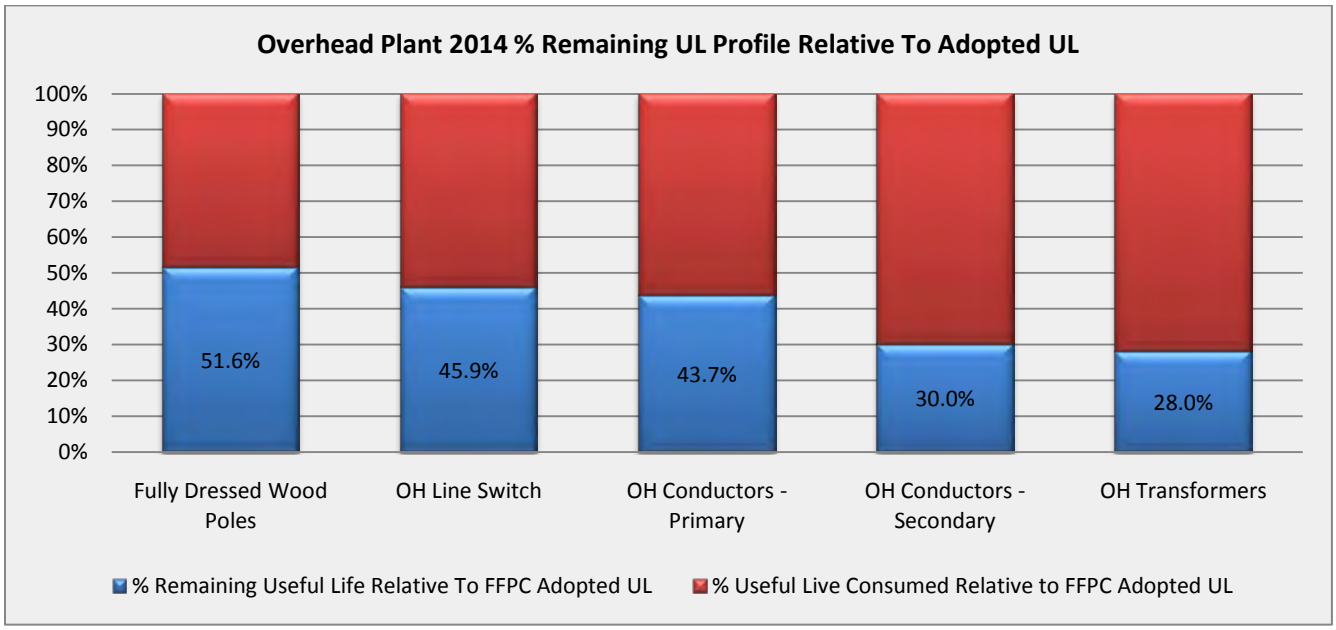
FFPC's asset management process has established a total asset replacement cost of $24,379,821 for all existing assets managed, based on FFPC's current cost structure (relative to 2013 pricing). Based on FFPC's adopted useful life values for each asset category, the average annual reinvestment needed to keep pace with asset deterioration is $618,169. The overall % remaining useful life (relative to FFPC's adopted UL and replacement cost) of all assets owned is 41.4%. FFPC's long term objective is to maintain a 50% "Remaining UL" profile where possible, to smooth long term spending requirements in the interest of long term rate stability. As such, FFPC's optimal annual capital reinvestment rate is $618,169, which is necessary to sustain the lifecycles of all assets managed, thereby keeping pace with asset deterioration. FFPC recognizes; however, that its' Greater than 50 kV Transformer Stations is made up of a small number of high priced assets that require sporadic long term investments. FFPC has therefore adjusted its optimal annual reinvestment rate, to only include costs related to necessary Transformer Station reinvestments over the planning period, as identified through the asset management process (lifecycle analyses). As such, FFPC's optimal annual reinvestment rate is $568,857 and FFPC has targeted an average annual reinvestment rate of $555,193. The actual average reinvestment rate is approximately 2.5% lower than the optimal; as FFPC is targeting overall cost reductions of 2.5% attributed to improved planning and asset oversight. The following table summarizes FFPC's assets, Useful Life Assessments, Investment Boundaries and Capital Budget Allocations for all lifecycle sustaining reinvestments:

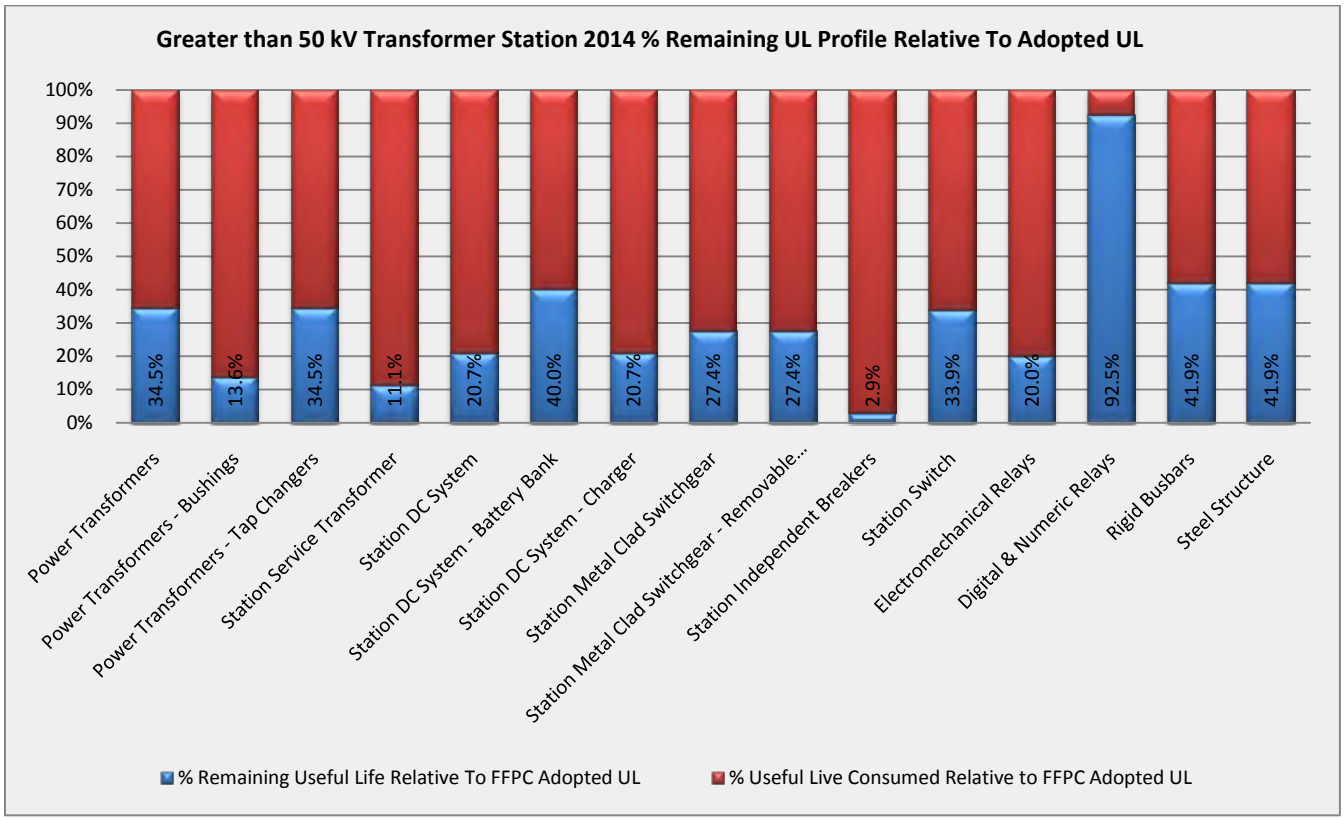
FFPC Asset Summary, Useful Life Assessment, Investment Boundaries and Capital Budget Allocations

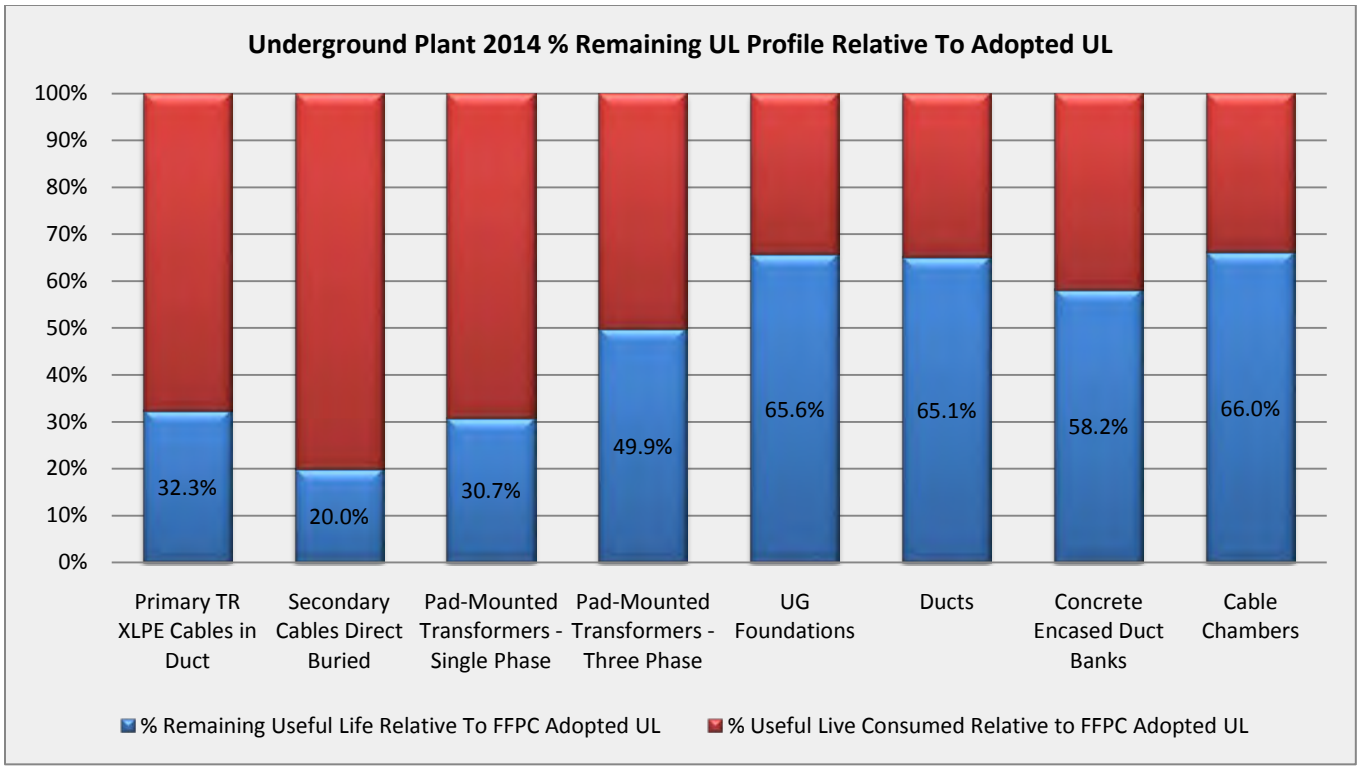
		Asset Details			FFPC Assets			Kinectrics Useful Life			Useful Life Assessment					Reinvestment Needs Assessment					Capital Budget Allocation		
Parent*	#	Category| Component | Type			Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to Kinectrics TUL	% Remaining Useful Life Relative to Kinectrics TUL	Remaining Useful Life Relative to FFPC Adopted UL	% Remaining Useful Life Relative To FFPC Adopted UL	Total Replacement Cost of Asset Group	Average Annual Reinvestment Need Based on Kinectrics Min UL	Average Annual Reinvestment Need Based on Kinectrics TUL	Average Annual Reinvestment Need Based on Kinectrics Max UL	Average Annual Reinvestment Need Based on FFPC Adopted UL	Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2044 to 2018)	% of Total DS Plan Capital Expenditures
OH	1	Fully Dressed Wood Poles	Overall		1776	Each	21.79	35	45	75	45	23.21	51.58%	23.21	51.6%	$ 5,850,761	$ 167,165	$ 130,017	$ 78,010	**$ 130,017**	$ 679,638	$ 135,928	19.3%
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	2	Fully Dressed Concrete Poles	Overall		N/A			50	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	3	Fully Dressed Steel Poles	Overall		N/A			60	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	4	OH Line Switch (Expressed as sets of 3 Phase Switches)			35	Each	24.34	30	45	55	45	20.66	45.90%	20.66	45.9%	$ 254,409	$ 8,480	$ 5,654	$ 4,626	**$ 5,654**	$ 32,500	$ 6,500	0.9%
	5	OH Line Switch Motor			N/A			15	25	25													
	6	OH Line Switch RTU			N/A			15	20	20													
	7	OH Integral Switches			N/A			35	45	60													
	8	OH Conductors	Primary Conductor		224.2	km	33.77	50	60	75	60	26.23	43.72%	26.23	43.7%	$ 676,409	$ 13,528	$ 11,273	$ 9,019	**$ 11,273**	$ -	$ -	0.0%
			Secondary Conductor		114.8	km	28.00	25	35	40	40	7.00	20.00%	12.00	30.0%	$ 1,033,603	$ 41,344	$ 29,532	$ 25,840	**$ 25,840**	$ 50,000	$ 10,000	1.4%
	9	OH Transformers			629	Each	28.79	30	40	60	40	11.21	28.02%	11.21	28.0%	$ 2,751,265	$ 91,709	$ 68,782	$ 45,854	**$ 68,782**	$ 491,617	$ 98,323	14.0%
	10	OH Shunt Capacitor Banks			N/A			25	30	40													
	11	Reclosers			N/A			25	40	55													
TS & MS	12	Power Transformers	Overall		2	Each	38.00	30	45	60	58	7.00	15.56%	20.00	34.5%	$ 1,930,575	$ 64,352	$ 42,902	$ 32,176	**$ 33,286**	$ -	$ -	0.0%
			Bushing		12	Each	38.00	10	20	30	44	0.00	0.00%	6.00	13.6%	$ 68,351	$ 6,835	$ 3,418	$ 2,278	**$ 1,553**	$ -	$ -	0.0%
			Tap Changer		2	Each	38.00	20	30	60	58	0.00	0.00%	20.00	34.5%	$ 1,127,792	$ 56,390	$ 37,593	$ 18,797	**$ 19,445**	$ -	$ -	0.0%
	13	Station Service Transformer			1	Each	40.00	30	45	55	45	5.00	11.11%	5.00	11.1%	$ 8,544	$ 285	$ 190	$ 155	**$ 190**	$ -	$ -	0.0%
	14	Station Grounding Transformer			N/A	Each		30	40	40													
	15	Station DC System	Overall		2	Each	23.00	10	20	30	29	0.00	0.00%	6.00	20.7%	$ 85,439	$ 8,544	$ 4,272	$ 2,848	**$ 2,946**	$ -	$ -	0.0%
			Battery Bank		2	Each	9.00	10	15	15	15	6.00	40.00%	6.00	40.0%	$ 51,263	$ 5,126	$ 3,418	$ 3,418	**$ 3,418**	$ 10,000	$ 2,000	0.3%
			Charger		2	Each	23.00	20	20	30	29	0.00	0.00%	6.00	20.7%	$ 34,176	$ 1,709	$ 1,709	$ 1,139	**$ 1,178**	$ 22,000	$ 4,400	0.6%
	16	Station Metal Clad Switchgear	Overall		11	Each	45.00	30	40	60	62	0.00	0.00%	17.00	27.4%	$ 845,844	$ 28,195	$ 21,146	$ 14,097	**$ 13,643**	$ -	$ -	0.0%
			Removable Breaker		11	Each	45.00	25	40	60	62	0.00	0.00%	17.00	27.4%	$ 205,053	$ 8,202	$ 5,126	$ 3,418	**$ 3,307**	$ -	$ -	0.0%
	17	Station Independent Breakers			1	Each	67.00	35	45	65	69	0.00	0.00%	2.00	2.9%	$ 138,411	$ 3,955	$ 3,076	$ 2,129	**$ 2,006**	$ 150,000	$ 30,000	4.3%
	18	Station Switch			5	Each	41.00	30	50	60	62	9.00	18.00%	21.00	33.9%	$ 68,351	$ 2,278	$ 1,367	$ 1,139	**$ 1,102**	$ -	$ -	0.0%
	19	Electromechanical Relays			34	Each	36.00	25	35	50	45	0.00	0.00%	9.00	20.0%	$ 131,576	$ 5,263	$ 3,759	$ 2,632	**$ 2,924**	$ -	$ -	0.0%
	20	Solid State Relays			N/A	Each		10	30	45													
	21	Digital & Numeric Relays			8	Each	1.50	15	20	20	20	18.50	92.50%	18.50	92.5%	$ 56,390	$ 3,759	$ 2,819	$ 2,819	**$ 2,819**	$ -	$ -	0.0%
	22	Rigid Busbars			3	Each	36.00	30	55	60	62	19.00	34.55%	26.00	41.9%	$ 42,719	$ 1,424	$ 777	$ 712	**$ 689**	$ -	$ -	0.0%
	23	Steel Structure			1	Each	36.00	35	50	90	62	14.00	28.00%	26.00	41.9%	$ 136,702	$ 3,906	$ 2,734	$ 1,519	**$ 2,205**	$ 25,000	$ 5,000	0.7%
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			N/A			60	65	75													
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			N/A			20	25	25													
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			N/A			20	25	30													

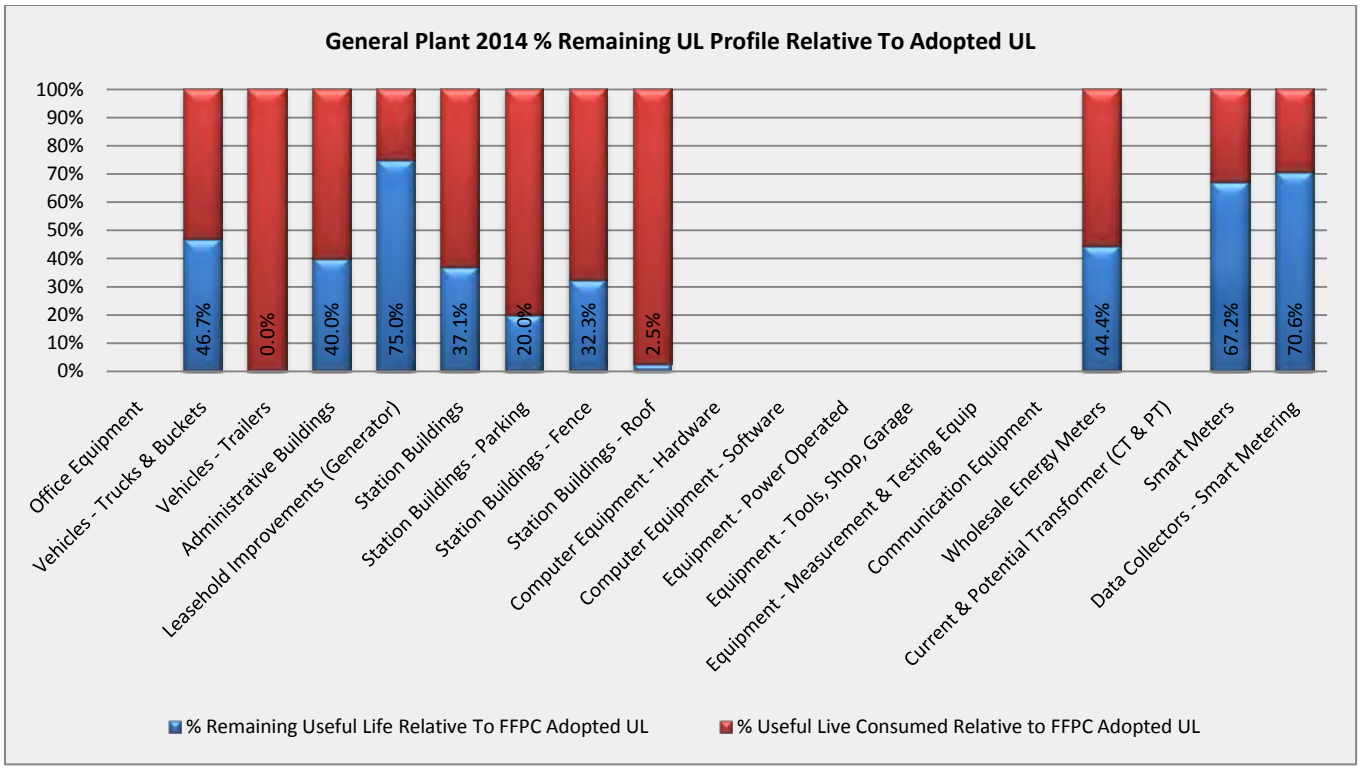
	27	Primary Non-TR XLPE Cables in Duct		N/A			20	25	30													
	28	Primary TR XLPE Cables Direct Buried		N/A			25	30	35													
	29	Primary TR XLPE Cables in Duct		30.7	km	27.07	35	40	55	40	12.93	32.32%	12.93	32.3%	$ 931,695	$ 26,620	$ 23,292	$ 16,940	**$ 23,292**	$ 180,537	$ 36,107	5.1%
	30	Secondary PILC Cables		N/A			70	75	80													
	31	Secondary Cables Direct Buried		3.8	km	28.00	25	35	40	35	7.00	20.00%	7.00	20.0%	$ 68,366	$ 2,735	$ 1,953	$ 1,709	**$ 1,953**	$ 10,000	$ 2,000	0.3%
	32	Secondary Cables in Duct		N/A			35	40	60													
	33	Network Transformers	Overall	N/A			20	35	50													
			Protector	N/A			20	35	40													
	34	Pad-Mounted Transformers	Single Phase	215	Each	27.70	25	40	45	40	12.30	30.74%	12.30	30.7%	$ 2,218,967	$ 88,759	$ 55,474	$ 49,310	**$ 55,474**	$ 368,761	$ 73,752	10.5%
			Three Phase	38	Each	20.05	25	40	45	40	19.95	49.87%	19.95	49.9%	$ 808,033	$ 32,321	$ 20,201	$ 17,956	**$ 20,201**	$ 147,163	$ 29,433	4.2%
	35	Submersible/Vault Transformers		N/A			25	35	45													
	36	UG Foundation		170	Each	27.52	35	55	70	80	27.48	49.97%	52.48	65.6%	$ 814,956	$ 23,284	$ 14,817	$ 11,642	**$ 10,187**	$ -	$ -	0.0%
	37	UG Vaults	Overall	N/A			40	60	80													
			Roof	N/A			20	30	45													
	38	UG Vault Switches		N/A			20	35	50													
	39	Pad-Mounted Switchgear		N/A			20	30	45													
	40	Ducts		23.5	km	27.95	30	50	85	80	22.05	44.10%	52.05	65.1%	$ 322,801	$ 10,760	$ 6,456	$ 3,798	**$ 4,035**	$ -	$ -	0.0%
	41	Concrete Encased Duct Banks		1.9	km	33.46	35	55	80	80	21.54	39.16%	46.54	58.2%	$ 712,998	$ 20,371	$ 12,964	$ 8,912	**$ 8,912**	$ -	$ -	0.0%
	42	Cable Chambers		5	Each	20.40	50	60	80	60	39.60	66.00%	39.60	66.0%	$ 35,000	$ 700	$ 583	$ 438	**$ 583**	$ -	$ -	0.0%
S	43	Remote SCADA		N/A			15	20	30													
	1	Office Equipment		Unknown	Each	Unknown	*5*	*10.0*	*15*	15	Unknown	Unknown	Unknown	Unknown	$ 60,000	$ 12,000	$ 6,000	$ 4,000	**$ 4,000**	$ 15,000	$ 3,000	0.4%
	2	Vehicles	Trucks & Buckets	7	Each	8.00	*5*	*10.0*	*15*	15	2.00	20.00%	7.00	46.7%	$ 801,000	$ 160,200	$ 80,100	$ 53,400	**$ 53,400**	$ 328,000	$ 65,600	9.3%
			Trailers	2	Each	26.00	*5*	*12.5*	*20*	20	0.00	0.00%	0.00	0.0%	$ 75,000	$ 15,000	$ 6,000	$ 3,750	**$ 3,750**	$ 75,000	$ 15,000	2.1%
			Vans	N/A			*5*	*7.5*	*10*													
	3	Administrative Buildings		1	Each	45.00	*50*	*62.5*	*75*	75	17.50	28.00%	30.00	40.0%	$ 550,000	$ 11,000	$ 8,800	$ 7,333	**$ 7,333**	$ 65,000	$ 13,000	1.8%
	4	Leasehold Improvements (Generator)		1	Each	5.00	*20*	*20.0*	*20*	20	15.00	75.00%	15.00	75.0%	$ 86,122	$ 4,306	$ 4,306	$ 4,306	**$ 4,306**	$ -	$ -	0.0%
	5	Station Buildings	Station Buildings	2	Each	39.0	*50*	*62.5*	*75*	62	23.50	37.60%	23.00	37.1%	$ 368,375	$ 7,368	$ 5,894	$ 4,912	**$ 5,942**	$ 31,000	$ 6,200	0.9%
			Parking	1	Each	24.00	*25*	*27.5*	*30*	30	3.50	12.73%	6.00	20.0%	$ 5,000	$ 200	$ 182	$ 167	**$ 167**	$ -	$ -	0.0%
			Fence	1	Each	42.00	*25*	*42.5*	*60*	62	0.50	1.18%	20.00	32.3%	$ 22,500	$ 900	$ 529	$ 375	**$ 363**	$ -	$ -	0.0%
			Roof	2	Each	39.00	*30*	*30.0*	*30*	40	0.00	0.00%	1.00	2.5%	$ 30,000	$ 1,000	$ 1,000	$ 1,000	**$ 750**	$ -	$ -	0.0%
	6	Computer Equipment	Hardware	Unknown	Each	Unknown	*3*	*4.0*	*5*	5	Unknown	Unknown	Unknown	Unknown	$ 32,000	$ 10,667	$ 8,000	$ 6,400	**$ 6,400**	$ 35,500	$ 7,100	1.0%
			Software	Unknown	Each	Unknown	*2*	*3.5*	*5*	5	Unknown	Unknown	Unknown	Unknown	$ 76,000	$ 38,000	$ 21,714	$ 15,200	**$ 15,200**	$ -	$ -	0.0%
General Plant	7	Equipment	Power Operated	Unknown	Each	Unknown	*5*	*7.5*	*10*	7	Unknown	Unknown	Unknown	Unknown	$ 7,000	$ 1,400	$ 933	$ 700	**$ 1,000**	$ 30,500	$ 6,100	0.9%
			Stores	N/A			*5*	*7.5*	*10*													
			Tools, Shop, Garage Equip.	Unknown	Each	Unknown	*5*	*7.5*	*10*	10	Unknown	Unknown	Unknown	Unknown	$ 10,000	$ 2,000	$ 1,333	$ 1,000	**$ 1,000**			
			Measurement & Testing Equip	Unknown	Each	Unknown	*5*	*7.5*	*10*	8	Unknown	Unknown	Unknown	Unknown	$ 65,000	$ 13,000	$ 8,667	$ 6,500	**$ 8,125**			
	8	Communication	Towers	N/A			*60*	*65.0*	*70*													
			Wireless	Unknown	Each	Unknown	*2*	*6.0*	*10*	10	Unknown	Unknown	Unknown	Unknown	$ 9,600	$ 4,800	$ 1,600	$ 960	**$ 960**	$ -	$ -	0.0%
	9	Residential Energy Meters		N/A			*25*	*30.0*	*35*													
	10	Industrial/Commercial Energy Meters		N/A			*25*	*30.0*	*35*													
	11	Wholesale Energy Meters		2	Each	5.00	*15*	*22.5*	*30*	9	17.50	77.78%	4.00	44.4%	$ 18,000	$ 1,200	$ 800	$ 600	**$ 2,000**	$ -	$ -	0.0%
	12	Current & Potential Transformer (CT & PT)		479	Each	Unknown	*35*	*42.5*	*50*	40	Unknown	Unknown	Unknown	Unknown	$ 85,262	$ 2,436	$ 2,006	$ 1,705	**$ 2,132**	$ 12,500	$ 2,500	0.4%
	13	Smart Meters		3966	Each	4.92	*5*	*10.0*	*15*	15	5.08	50.76%	10.08	67.2%	$ 650,543	$ 130,109	$ 65,054	$ 43,370	**$ 43,370**	$ 16,250	$ 3,250	0.5%
	14	Repeaters - Smart Metering		N/A			*10*	*12.5*	*15*													
	15	Data Collectors - Smart Metering		7	Each	5.00	*15*	*17.5*	*20*	17	12.50	71.43%	12.00	70.6%	$ 17,972	$ 1,198	$ 1,027	$ 899	**$ 1,057**	$ -	$ -	0.0%
Totals															$ 24,379,820.51	$ 1,144,782	$ 739,250	$ 519,907	**$ 618,169**	**$ 2,775,966**	**$ 555,193**	**78.8%**

The following graphs illustrate the percentage of remaining and consumed useful life of FFPC's asset base, by asset category (Please note that the age profiles for Equipment categories are not known at this time, and as such they have been left blank. FFPC plans to obtain the missing age profile data over the course of the planning horizon):



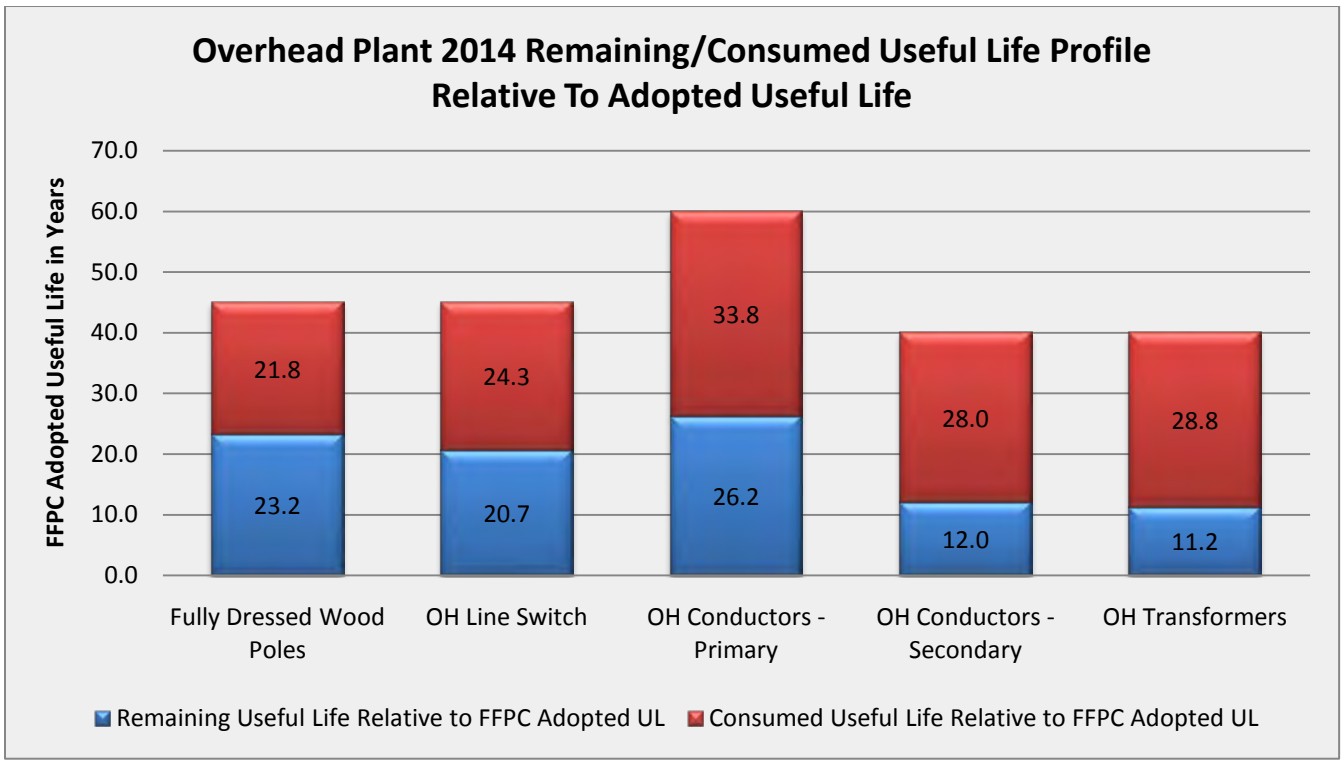


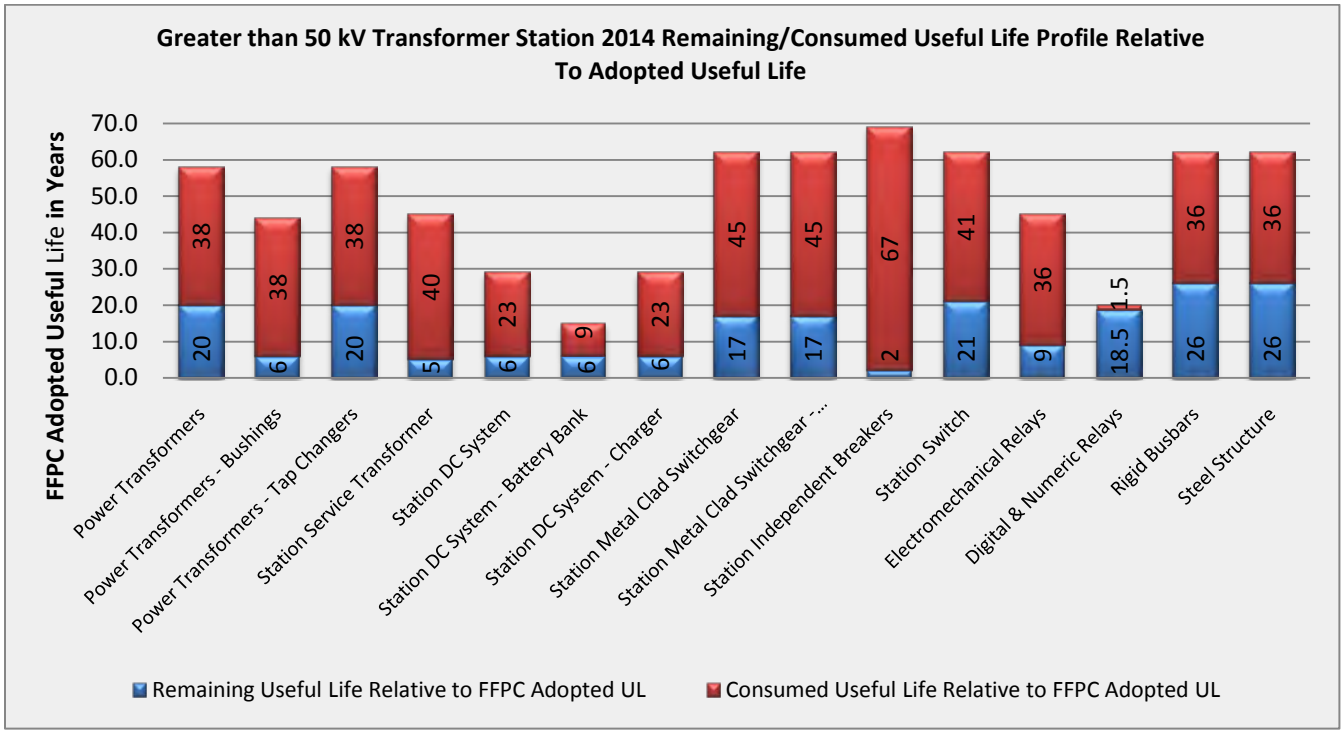


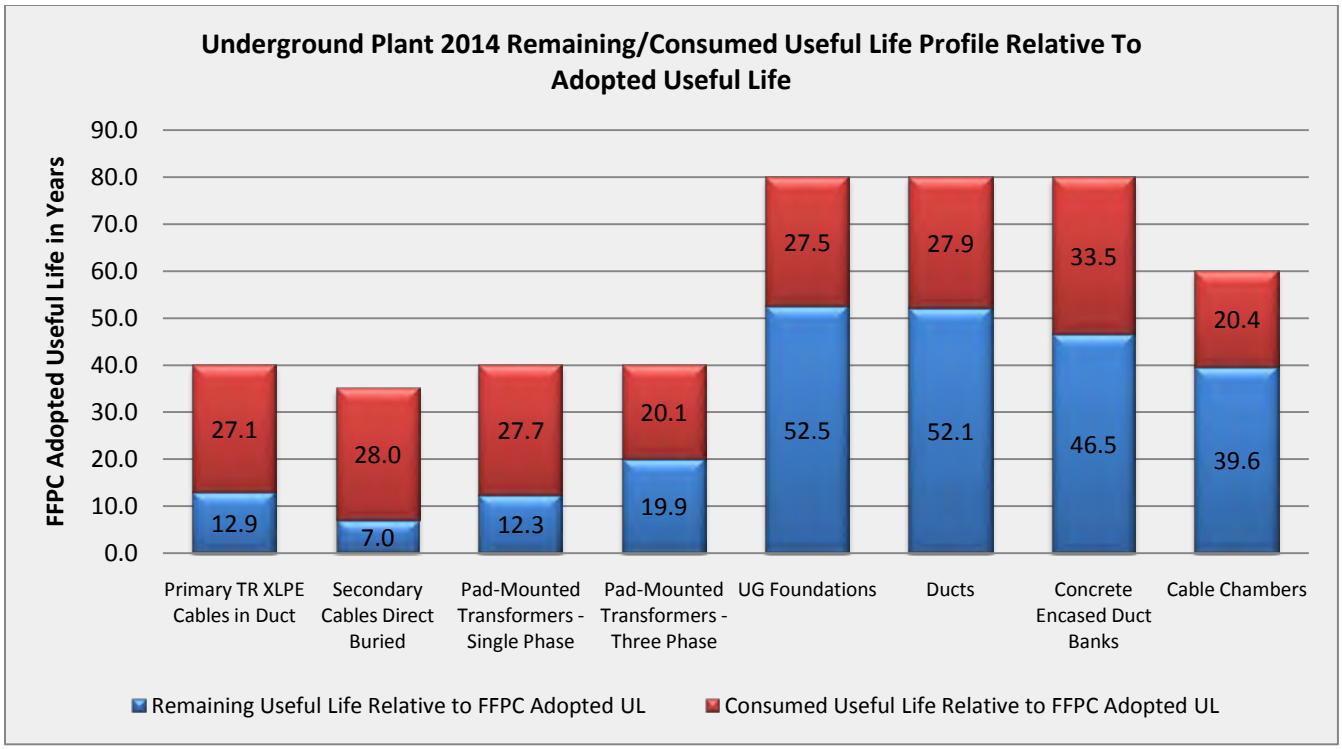


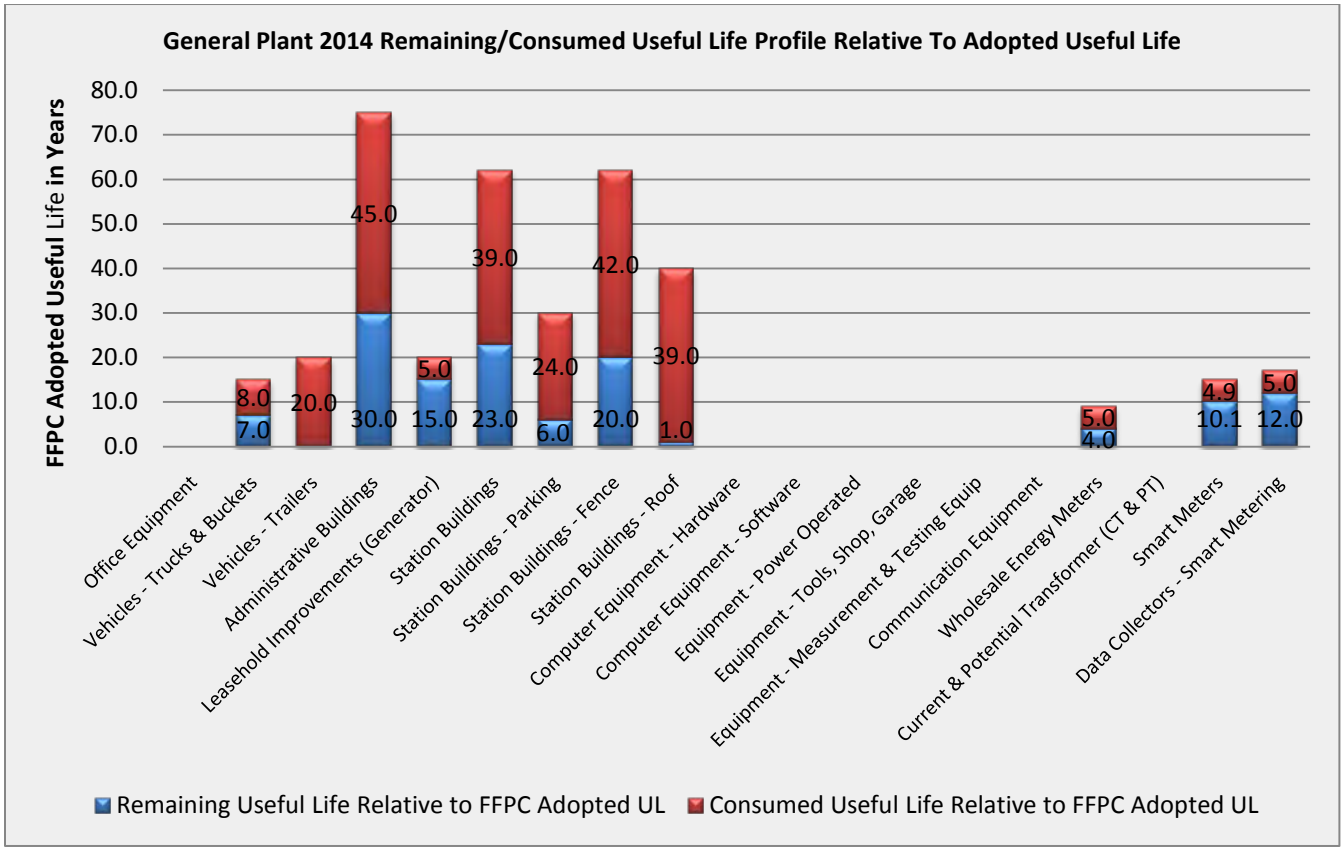
Note: Age profiles are not yet available for the Equipment related categories.

The following graphs illustrate the remaining and consumed years of useful life of FFPC's asset base, by asset category:









Note: Age profiles are not yet available for the Equipment related categories.

As previously mentioned, lifecycle sustaining capital reinvestments account for $2,775,966 (78.8%) of the total $3,522,205 capital investment needs identified, for the 2014 to 2018 planning period. The remaining portion of capital investment needs is required to address meeting other business objectives, addressing mandatory or legal obligations, as well as accommodating stakeholder needs (customer engagement activities). FFPC has allocated the following capital: $149,500 to address meeting business objectives, $538,739 to address meeting mandated service obligations, as well as $58,000 in response to customer preference. For filing purposes, FFPC has grouped and summarized its investment projects according to Section 5.1.1 of the Chapter 5 filing guide. As such, the following table summarizes the planned capital investments by category and investment driver, as well as the subsequent table illustrates the relative importance of each investment driver based on its percentage of the total planned investments:

FFPC 2014 to 2018 Planned Capital Expenditures by Investment Category							
Investment Category	**Investment Driver**	**2014**	**2015**	**2016**	**2017**	**2018**	**2014 - 2018 Total**
		Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Total Planned Expenditures
System Access	Mandated Service Obligations	$ 421,739	$ 40,000	$ 20,000	$ 45,000	$ 12,000	$ 538,739
	3rd Party Infrastructure Development	$ -	$ -	$ -	$ -	$ -	$ -
	Customer Service Requests	$ -	$ -	$ -	$ -	$ -	$ -
System Renewal	EOL - Failure	$ 20,568	$ 8,608	$ 8,608	$ 8,608	$ 8,608	$ 54,999
	EOL - Failure Risk	$ 231,009	$ 408,255	$ 471,723	$ 520,363	$ 350,116	$ 1,981,466
	EOL - Functional Obsolescence	$ -	$ -	$ -	$ -	$ -	$ -
	EOL - High Performance Risk	$ 2,000	$ 2,000	$ 24,000	$ 2,000	$ 2,000	$ 32,000
	EOL - Substandard Performance	$ -	$ -	$ -	$ -	$ -	$ -
System Service	Customer Preference	$ -	$ 15,000	$ -	$ 43,000	$ -	$ 58,000
	Obj - Imp Performance/Functionality	$ -	$ -	$ -	$ -	$ -	$ -
	Obj - Power Quality	$ -	$ -	$ -	$ -	$ -	$ -
	Obj - Reliability	$ 14,500	$ 87,000	$ 40,000	$ 15,000	$ 15,000	$ 171,500
	Obj - Safety	$ 34,500	$ -	$ -	$ -	$ -	$ 34,500
	Obj - System Efficiency	$ 4,000	$ -	$ -	$ -	$ -	$ 4,000
General Plant	Non-System Physical Plant	$ 78,000	$ 50,500	$ 50,000	$ 23,000	$ 51,500	$ 253,000
	Business Operation Efficiency	$ 2,500	$ 40,000	$ 30,000	$ -	$ -	$ 72,500
	Other Performance/Functionality	$ 2,500	$ -	$ -	$ -	$ -	$ 2,500
	System Cap / Maintenance Support	$ 9,000	$ 25,000	$ 16,000	$ 10,000	$ 259,000	$ 319,000
Total Annual Capital Budget		$ 820,316	$ 676,363	$ 660,331	$ 666,971	$ 698,224	$ 3,522,205

FFPC 2014 to 2018 Planned Capital Expenditures by % Investment Driver							
Investment Category	Investment Driver	**2014**	**2015**	**2016**	**2017**	**2018**	**2014 - 2018 Total**
		% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Total Planned Expenditures
System Access	Mandated Service Obligations	51.4%	5.9%	3.0%	6.7%	1.7%	15.3%
	3rd Party Infrastructure Development	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Customer Service Requests	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
System Renewal	EOL - Failure	2.5%	1.3%	1.3%	1.3%	1.2%	1.6%
	EOL - Failure Risk	28.2%	60.4%	71.4%	78.0%	50.1%	56.3%
	EOL - Functional Obsolescence	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	EOL - High Performance Risk	0.2%	0.3%	3.6%	0.3%	0.3%	0.9%
	EOL - Substandard Performance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
System Service	Customer Preference	0.0%	2.2%	0.0%	6.4%	0.0%	1.6%
	Obj - Imp Performance/Functionality	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Obj - Power Quality	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Obj - Reliability	1.8%	12.9%	6.1%	2.2%	2.1%	4.9%
	Obj - Safety	4.2%	0.0%	0.0%	0.0%	0.0%	1.0%
	Obj - System Efficiency	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%
General Plant	Non-System Physical Plant	9.5%	7.5%	7.6%	3.4%	7.4%	7.2%
	Business Operation Efficiency	0.3%	5.9%	4.5%	0.0%	0.0%	2.1%
	Other Performance/Functionality	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%
	System Cap / Maintenance Support	1.1%	3.7%	2.4%	1.5%	37.1%	9.1%
	Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

The following tables illustrate FFPC's total planned capital expenditures by Investment Category:

Investment Category	2014	2015	2016	2017	2018	2014 - 2018 Total
	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)
System Access	421.7	40.0	20.0	45.0	12.0	538.7
System Renewal	253.6	418.9	504.3	531.0	360.7	2068.5
System Service	48.5	142.0	60.0	58.0	15.0	323.5
General Plant	96.5	75.5	76.0	33.0	310.5	591.5
Total	820.3	676.4	660.3	667.0	698.2	3522.2
System O&M	24.3	13.0	7.1	7.8	2.5	54.7

Investment Category	2014	2015	2016	2017	2018	2014 - 2018 Total
	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Planned Expenditures	% of Total Planned Expenditures
% System Access	51.4%	5.9%	3.0%	6.7%	1.7%	15.3%
% System Renewal	30.9%	61.9%	76.4%	79.6%	51.7%	58.7%
% System Service	5.9%	21.0%	9.1%	8.7%	2.1%	9.2%
% General Plant	11.8%	11.2%	11.5%	4.9%	44.5%	16.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Of the total $3,522,205 in total planned capital expenditures over the 2014 to 2018 planning period, 58.7% are towards System Renewal, 16.3% are towards General Plant, 15.3% are towards System Access and 9.2% are towards System Service.

The "Kinectrics Asset Depreciation Study for the Ontario Energy Board" was of great assistance in the development of this DS Plan, as well as in the development of FFPC's Asset Management Process. FFPC would like to give credit to the authors of the report for the valuable body of work, as well as to the OEB for having the foresight to undertake the project. The following table illustrates FFPC's 2014 to 2018 planned capital investments by asset class, as per the Kinectrics Report.

FFPC 2014 - 2018 Capital Expenditure Summary By Kinectrics Asset Class						
Kinectrics Asset Class	2014	2015	2016	2017	2018	2014 - 2018 Total
	Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Planned Expenditures	Total Planned Expenditures
1 - Fully Dressed Wood Poles	$ 434,609	$ 134,928	$ 134,928	$ 134,928	$ 134,928	$ 974,319
4 - OH Line Switch	$ 32,500	$ -	$ -	$ -	$ -	$ 32,500
8 - OH Conductors	$ 11,180	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 59,180
9 - OH Transformers	$ 98,086	$ 104,894	$ 68,081	$ 129,709	$ 129,428	$ 530,197
Overhead Totals	**$ 576,375**	**$ 251,821**	**$ 215,009**	**$ 276,636**	**$ 276,355**	**$ 1,596,197**
12 - Power Transformers	$ -	$ -	$ -	$ -	$ -	$ -
13 - Station Service Transformer	$ -	$ -	$ -	$ -	$ -	$ -
15 - Station DC System	$ 2,000	$ 2,000	$ 24,000	$ 2,000	$ 2,000	$ 32,000
16 - Station Metal Clad Switchgear	$ -	$ -	$ -	$ -	$ -	$ -
17 - Station Independent Breakers	$ -	$ -	$ 150,000	$ -	$ -	$ 150,000
18 - Station Switch	$ -	$ -	$ -	$ -	$ -	$ -
19 - Electromechanical Relays	$ -	$ -	$ -	$ -	$ -	$ -
21 - Digital & Numeric Relays	$ 50,000	$ -	$ 20,000	$ -	$ -	$ 70,000
22 - Rigid Busbars	$ -	$ -	$ -	$ -	$ -	$ -
23 - Steel Structure	$ -	$ -	$ 25,000	$ -	$ -	$ 25,000
TS & MS Totals	**$ 52,000**	**$ 2,000**	**$ 219,000**	**$ 2,000**	**$ 2,000**	**$ 277,000**
29 - Primary TR XLPE Cables in Duct	$ 18,549	$ 36,609	$ 6,573	$ 79,915	$ 41,189	$ 182,835
30 - Secondary PILC Cables	$ -	$ -	$ -	$ -	$ -	$ -
31 - Secondary Cables Direct Buried	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 10,000
33 - Network Tranformers	$ -	$ -	$ -	$ -	$ -	$ -
34 - Pad-Mounted Transformers	$ 36,142	$ 135,682	$ 115,999	$ 179,670	$ 48,430	$ 515,923
36 - UG Foundation	$ -	$ -	$ -	$ -	$ -	$ -
40 - Ducts	$ 27,000	$ -	$ -	$ -	$ -	$ 27,000
41 - Concrete Encased Duct Banks	$ -	$ -	$ -	$ -	$ -	$ -
42 - Cable Chambers	$ -	$ -	$ -	$ -	$ -	$ -
UG Totals	**$ 83,691**	**$ 174,292**	**$ 124,572**	**$ 261,585**	**$ 91,619**	**$ 735,758**

43 - Remote SCADA	$ -	$ 20,000	$ -	$ 45,000	$ 12,000	$ 77,000
G1 - Office Equipment	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 15,000
G2 - Vehicles	$ 50,000	$ 38,000	$ 40,000	$ -	$ 275,000	$ 403,000
G3 - Administrative Buildings	$ 11,000	$ 21,500	$ 15,000	$ 8,000	$ 9,500	$ 65,000
G4 - Leasehold Improvements (Generator)	$ -	$ -	$ -	$ -	$ -	$ -
G5 - Station Buildings	$ 5,000	$ 74,000	$ 5,000	$ 5,000	$ 4,000	$ 93,000
G6 - Computer Equipment	$ 19,500	$ 46,000	$ 21,000	$ 55,000	$ 1,000	$ 142,500
G7 - Equipment	$ 14,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 34,000
G8 - Communication	$ -	$ 35,000	$ 7,000	$ -	$ 13,000	$ 55,000
G11 - Wholesale Energy Meters	$ -	$ -	$ -	$ -	$ -	$ -
G12 - Current & Potential Transformer (CT & PT)	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 12,500
G13 - Smart Meters	$ 3,250	$ 3,250	$ 3,250	$ 3,250	$ 3,250	$ 16,250
G15 - Data Collectors - Smart Metering	$ -	$ -	$ -	$ -	$ -	$ -
General Plant Totals	**$ 108,250**	**$ 248,250**	**$ 101,750**	**$ 126,750**	**$ 328,250**	**$ 913,250**
Grand Total	***$ 820,316***	***$ 676,363***	***$ 660,331***	***$ 666,971***	***$ 698,224***	***$ 3,522,205***

With respect to the Kinectrics Report asset grouping, the following asset classes are ranked in order of importance with respect to the amount of capital investment allocated towards each of them:

FFPC 2014 - 2018 Capital Expenditure Summary By Asset Class		
Kinectrics Asset Class	**2014 - 2018 Total**	
	Total Planned Expenditures	% of Total Planned Expenditures
1 - Fully Dressed Wood Poles	$ 974,319	27.7%
9 - OH Transformers	$ 530,197	15.1%
34 - Pad-Mounted Transformers	$ 515,923	14.6%
G2 - Vehicles	$ 403,000	11.4%
29 - Primary TR XLPE Cables in Duct	$ 182,835	5.2%
17 - Station Independent Breakers	$ 150,000	4.3%
G6 - Computer Equipment	$ 142,500	4.0%
G5 - Station Buildings	$ 93,000	2.6%
43 - Remote SCADA	$ 77,000	2.2%
21 - Digital & Numeric Relays	$ 70,000	2.0%
G3 - Administrative Buildings	$ 65,000	1.8%
8 - OH Conductors	$ 59,180	1.7%
G8 - Communication	$ 55,000	1.6%
G7 - Equipment	$ 34,000	1.0%
4 - OH Line Switch	$ 32,500	0.9%
15 - Station DC System	$ 32,000	0.9%
40 - Ducts	$ 27,000	0.8%
23 - Steel Structure	$ 25,000	0.7%
G13 - Smart Meters	$ 16,250	0.5%
G1 - Office Equipment	$ 15,000	0.4%
G12 - Current & Potential Transformer (CT & PT)	$ 12,500	0.4%
31 - Secondary Cables Direct Buried	$ 10,000	0.3%
Grand Total	***$ 3,522,205***	100.0%

Almost 60% of all investments planned, are allocated towards the replacement or refurbishment of Fully Dressed Wood Poles, Overhead and Pad-Mounted Transformers. With respect to the Kinectrics Report asset groupings, FFPC's total planned expenditures are: 45.3% or $1,596,197 towards Overhead Plant; 25.9% or $913,250 towards General Plant; $20.9% or $735,758 towards Underground Plant; and 7.9% or $277,000 towards Transformer Stations.

5.2.1.5 Unique Embedded OM&A Costs

FFPC's operating circumstances are unique from other distributors in that it administers a 1905 Historic Power Agreement, which is explained below in section 5.2.1.5.b, on behalf of FFPC ratepayers, as well as it owns and

operates a Greater than 50 kV Transformer Station. FFPC essentially has an "expanded businesses scope" such that all three aspects are managed in a cost effective manner under one umbrella. FFPC's management of the agreement and the station is of great benefit to ratepayers, as their cost of electricity is thereby significantly reduced as reflected on their total bill. With the inclusion of these consumer benefits, FFPC's customers enjoy the lowest rates for electricity within the province of Ontario. The administration of both additional business aspects are deeply entrenched into the day-to-day operation of the utility, and administrative costs related to their upkeep are not segregated from regular distribution related administrative expenses.

Given the increased focus on distributor efficiency and the pressure to "bend the cost curve", FFPC is very concerned that its unique operating circumstances which materially inflate OM&A costs, may not been taken into account when establishing cost related performance measures. As such, FFPC is concerned about being unjustly penalized in the establishment of its "Efficiency" and "Productivity Ratings", which are also key inputs for the assignment of Stretch Factors for rate setting purposes. The methodology contained in PEG Reporting that establish OEB Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, underscore the importance of ensuring "apples to apples" benchmarking across distributors. This highlights the need for FFPC's unique circumstances to be taken into consideration when establishing its performance measures. FFPC's OM&A costs incurred essentially support three distinct business functions; a distribution business; a high voltage transformer station business; as well as a 1905 Historic Power Agreement business. Administrative costs; however, have historically not been segregated and allocated to each aspect. Segregation and allocation of costs is difficult due to the intertwined nature of the expense components. FFPC would like to underscore that although its OM&A expenses may appear higher than its peer group or established "targets", they are prudently incurred in the best interest of its customers.

5.2.1.5.a. Greater Than 50 kV Transformer Station ("Fort Frances MTS")

FFPC incurs significant expense associated with the ownership and operation of its high voltage transformer station, which in essence decreases Transmission costs and distorts distribution costs. The station represents 20.1% of FFPC's current asset base, relative to its replacement cost divided by the total replacement cost of all assets owned (based on the replacement value obtained from FFPC's insurance carrier). Prior to 2012, the greater than 50 kV transformer station was incorrectly classified as a "less than 50 kV Transformer Station" with respect to USoA account coding and as such all associated historic costs would be interpreted as "distribution costs". Due to this oversight, historical benchmarking of FFPC's performance is likely to not be accurate, as OM&A costs are significantly inflated. In addition as previously mentioned, administrative related expenses have historically not been allocated toward the upkeep and operation of the station.

5.2.1.5.b. 1905 Historic Power Agreement

As the Board is aware, the residents and small businesses of the Town of Fort Frances are beneficiaries of a 1905 Agreement entered into between the Town and the local pulp and paper mill. The 1905 Agreement obligates the mill owner, or more precisely today, the owner of the generation assets on the Rainy River (today, H2O Power LP ("H2O")), to provide to the Town of Fort Frances, in perpetuity, 4,000 horsepower (2.984 Megawatts)

at $14 per horsepower per annum (0.21416 cents per kilowatt hour) “for municipal purposes and for public utilities” [Fort Frances v Boise Cascade Canada Ltd., [1983] 1 SCR 171 at 184].

The 1905 Agreement is filed as a physical bilateral contract with the IESO and represents a financial obligation of H2O. Essentially, for 2.984 Megawatts, which represents approximately 25% of the power purchases of FFPC, H2O pays to the IESO the additional costs of power above 0.21416 cents per kilowatt hour, and the IESO credits FFPC for that amount. FFPC in turn credits its customers who, in effect, pay a blended commodity rate reflecting the benefit of the 1905 Agreement. The amount of the benefit currently exceeds $2.2 million annually, which is approximately 120% of FFPC’s total annual collected distribution revenue. The administration of the agreement is deeply embedded into the day-to-day operation of many administration related matters. Some of these activities include: agreement value determination; review of regulations; adjustments to conform to regulatory reporting formats; calculation and implementation of credits and rebates; billing and customer communications. Further to this, FFPC periodically incurs significant expense to preserve the agreement in the face of regulatory and government policy changes, as well as in defending it at legal proceedings. The most notable legal proceeding lead to a Supreme Court of Canada ruling in 1983, at which time it was established that the owner of the generation assets provide to the Town of Fort Frances, in perpetuity, 4000 horsepower (2.984 Megawatts) at $14 per horsepower per annum, “for municipal purposes and for public utilities”.

The agreement underpins FFPC’s operating strategy, as it is the fundamental reason why FFPC operates under a zero percent rate-of-return of common equity, so as to not violate “commercialization” prohibiting clauses in the Supreme Court ruling of the agreement. As such, the agreement is a cornerstone of FFPC’s business.

FFPC formally voiced its concerns regarding the measurement of its performance in light of the 1905 Historic Power Agreement, in the Board’s consultation “Defining and Measuring Performance of Electricity Transmitters and Distributors” (EB-2010-0379). Please refer to Appendix 5 for the June 24, 2013 submission. FFPC would be pleased to have the opportunity to work with the Board, as well as with the Board’s consultants, such as PEG Group, to address FFPC’s unique performance benchmarking circumstances.

5.2.1.6 Expected Cost Savings

FFPC has developed a first class asset management process that will enable considerable cost savings to be recognized through improved oversight of assets managed, thereby enabling more effective planning and decision making. The asset management process has enabled multiyear data driven planning and decision making. FFPC’s planning capabilities have improved significantly through the implementation of a GIS system, which has recently been complimented by formal asset management and capital planning processes. Good planning will result in wise spending, which will ultimately lead to customer cost savings.

FFPC performs an analysis on all of its assets by comparing the age of the assets relative to the “Typical-Useful-Life” (TUL) standards established in the July 8, 2010 “Kinectrics Asset Depreciation Study for the Ontario Energy Board” (“Kinectrics Report”). FFPC then performs further analyses to determine the likelihood of failure of every individual asset based on available condition data. Condition data sources include inspection results, condition testing results, asset performance data, employee expertise, root cause failure data from outage reports and manufacturer information such as known defects.

Utilizing these inputs, FFPC adjusts the "Typical-Useful-Life" expectancy of individual assets based on assessing their health. Favourable condition data extend the life expectancy of assets and conversely, unfavourable condition data decreases the life expectancy. Default life expectancies are set to FFPC's adopted useful life values, which are based on the useful life ranges established in the Kinectrics Report. It is worth noting that FFPC has adopted default useful life values that are either equal to, or longer than the TUL values established in the Kinectrics Report. Longer UL's are typically the result of FFPC's lifecycle optimization policies. The resulting end-of-life estimations for individual assets are referred to as "Adjusted End-of-Life" projections. The "Adjusted End-of-Life" values for individual assets essentially generate a listing that reflects FFPC's prediction as to the time of failure and the order in which assets will fail.

With the ability to project asset failures, FFPC can now make more educated decisions as to the opportune time to replace assets, balancing risk and reinvestment. With improved asset oversight, asset lifecycles can also be optimized. FFPC has aligned the lifecycles of various distribution system assets such that assets are not replaced prematurely. For example, a transformer base will be replaced every second time that the transformer mounted onto it is replaced. Similarly, underground ducts will be replaced every second time that the cables contained within them are replaced.

FFPC has quantified these cost savings based on a lifecycle costing methodology. FFPC's asset management process has established a total replacement value for all assets owned at $24.3 million dollars. The replacement value is the product of individual asset counts and their corresponding individual replacement cost. If FFPC were to adopt the minimum useful life values determined in the "Kinectrics Report", the normalized annual cost to sustain the lifecycles for all assets owned would be $1.14 million, whereas if FFPC was to adopt the maximum useful life values for all assets owned, the normalized annual cost to sustain the lifecycles would be reduced to $0.52 million.

Using the TUL values as determined in the "Kinectrics Report" as an industry benchmark, the normalized annual cost to sustain the lifecycles of Overhead, Underground, and General Plant owned would be $604,944. Through the implementation of FFPC's Asset Management process and corresponding "Adjusted End-of-Life Values", the normalized planned annual cost to sustain the lifecycles decreased to $527,458, resulting in annual savings of $77,487 or $387,433 over the planning period. FFPC has further reduced the actual average annual reinvestment amount towards sustaining the lifecycles of existing assets to $513,793. FFPC is hoping to achieve the additional reduction of $13,665 per year, through decreasing its asset base as a result of improved planning and system optimization efforts, as assets are replaced. FFPC is anticipating that transformer loading profiles, as well as other improved analytical data will become available in the near future, which will support identifying the targeted savings. Therefore, the total projected savings attributed to improved asset management and planning efforts is $455,757. The savings are expected to be realized as a result of effective planning, balancing risk and reinvestments, as well as through optimizing asset lifecycles.

The nature of Transformer Station investments is quite different from distribution plant, as they are sporadic and not conducive to annual "smoothing", unless a large quantity of stations are owned, such that their lifecycles could be staggered. As such, planning related savings have not yet been quantified.

FFPC has utilized its own internal resources towards the development of its GIS based Asset Management Process, Capital Planning Process as well as this DS Plan. The projected savings from utilizing internal resources to develop these fundamental tools, as opposed to outsourcing their development, is estimated to be in excess of $250,000.

FFPC also uses internal resources to develop and conduct annual customer surveys. FFPC estimates that this will save customers approximately $50,000 in avoided costs over the planning period.

Additional cost saving such as reduced maintenance costs and reduced distribution losses will also be achieved; however, they are more difficult to quantify with a high degree of confidence.

5.2.1.7 Period Covered by DS Plan

FFPC performed its last Rate Rebasing in 2006, under proceeding number EB-2005-0366. As such, for the purpose of continuity, historical information as available has been provided for the period 2006 to 2012. Detailed project information for the forecast period 2014 to 2018 is also included. Individual asset class end-of-life projections have also been included. The projections are based on FFPC's asset management process and they detail one complete lifecycle for all major asset classes. The projections are relative to 2014 and reach out as far as 80 years into the future.

5.2.1.8 Vintage of Investment Driver Information

Investment driver information is current as at September 30th, 2013, although FFPC has incorporated recently received stakeholder feedback as per the below. FFPC has incorporated the following relevant stakeholder feedback:

- Customers: Results of Customer Survey conducted July & August 2013
- OPA: Letter of Comment re FFPC DS Plan received August 30th, 2013
- OPA: Update that the northwest region is no longer considered capacity constrained and that 10 MW of additional renewable generation capacity have been allocated: October 17th, 2013
- HONI: Planning Status Letter received by way of email: October 21st, 2013

Consideration has also been given to the needs of the following stakeholders although no formal responses were received:

- *Regional Planning Consultation (No formal consultations conducted yet)*
- *Municipal Planning Office*
- *Fort Frances Emergency Control Group*

5.2.1.9 Changes to Distributor Asset Management Process

FFPC's formal asset management process was developed to fulfill the needs of the "Chapter 5 Consolidated Distribution System Plan Filing Requirements" and as such, no prior version existed. FFPC is very pleased with the OEB's impetus and guidance provided for the development of a formal asset management process, as well as for the creation of a formal Distribution System Plan. Through this effort, FFPC has been able to achieve improved oversight of its asset base enabling data driven long range planning, which will ultimately result in significant customer savings.

This DS Plan is built on the foundation of FFPC's Asset Management Process which has been integrated into a Geographical Information System. Over the 2014 to 2018 planning horizon, FFPC expects to enhance its asset management process through the deployment of a formal Work Order and Asset Management Planning software tool which was purchased in 2013. The tool will assist FFPC in tracking all relevant work performed on individual assets, enable asset specific cost tracking, as well as provide an asset based analytical calculation engine (for automatic generation of Health Indexes etc.).

5.2.1.10 Aspects of DS Plant Contingent upon Ongoing & Future Outcomes

There are several aspects contained within this DS Plan that are contingent upon the outcome of ongoing and future activities. The following aspects have the potential of significantly impacting the 2014 to 2018 DS Plan:

- Elimination of Long Terms Load Transfer Arrangements: There are currently fourteen (14) customers within FFPC's licensed electrical distribution service territory that are physically connected to and serviced by Hydro One Networks Inc.'s electrical distribution system. The customers are located in three separate locations and the customer count by location is twelve (12) one (1) and one (1) respectively. Over the course of history, FFPC has been approached by several LTLT customers requesting that FFPC extend its distribution system such that they can be connected to it and served by FFPC. FFPC's LTLT circumstances are unique from other LTLT arrangements, in that the customers are entitled to receive benefits from a 1905 Historic Power Agreement. Under the current circumstances FFPC is not able to distribute the 1905 Historic Power Agreement credits to them, as FFPC does not meter or bill the LTLT customers. Upon OEB approval for the capital distribution system expansion, FFPC is planning on extending its feeders to eliminate the LTLT's in 2014, as per the requirements of the DSC. The financial impact of this project is expected to be $371,739, which is planned to be incurred in 2014. The feeder expansions will unlock access to approximately 25% of FFPC's distribution service territory that is currently not developed. As a community partner, FFPC is also hopeful that the LTLT feeder expansions will spark economic activity.
- Renewable Generation Enabling Improvements: Upon OEB approval, FFPC is planning to move forward with instrumentation and control upgrades at its greater than 50 kV transformer station "Fort Frances MTS". The upgrades are necessary to accommodate reverse power flow at the station, to enhance equipment protection and to enable individual feeder performance monitoring for constraint setting purposes. The renewable enabling improvements will also accomplish many objectives of the Smart Grid directive including Customer Control, Power System Flexibility and Adaptive Infrastructure categories. The financial impact of this aspect on FFPC's DS Plan is expected to be $167k over the period

2014 to 2018. FFPC has previously incurred approximately $62k of eligible renewable enabling expense, for which it is also seeking recovery.

- Regional Planning Consultation: The regional planning consultation has the potential of significantly impacting FFPC's DS Plan; however, the consultations have not yet formally started and as such deliverables are still unknown. Due to unknown deliverables, FFPC acknowledges a potential impact but it cannot be quantified at this time.

5.2.1.11 FFPC Transition from Maintenance Mode to Capital Rebuild Mode

FFPC's entire electrical distribution system was rebuilt from the mid 1970's to mid 1980's. As a result of this rebuild and voltage conversion, FFPC has essentially operated in a maintenance mode over the last several decades. Capital reinvestment needs were low due to the overall age of the distribution assets being relatively new. Increased capital reinvestments are now required, to keep pace with the large volumes of assets approaching the end of their useful service life, posing a high risk of failure over the 2014 to 2018 planning period. As such, FFPC is planning to increase its capital reinvestments as dictated by the age and condition of its asset base (as determined by asset management and capital planning processes).

5.2.2 Coordinated planning with third parties

5.2.2.1 Regional Planning Consultations

At the time of preparing this DS Plan, the Regional Infrastructure Planning initiative is still in the early stages of development and as such many of the elements of the planning process have not yet been implemented. As per the "Integrated Planning Requirements - Part 1: Regional Infrastructure Planning" presentation to 2014 Cost of Service Application filers, the transition and implementation to Regional Infrastructure Planning (RIP) is expected to take four (4) years. In other words, it is expected to take four (4) years to complete the first iteration of the planning cycle.

FFPC owns and operates a transmission connected transformer station "Fort Frances MTS", which transforms the incoming 115 kV transmission supply to the outgoing 7.2/12.27 kV distribution voltage. In Exhibit 1 of this COS, FFPC formally requests that this transmission asset be deemed a distribution asset. It is anticipated that future deliverables from the Regional Infrastructure Planning (RIP) process will entail modifications to the transformer station, as the majority of the station is still of original 1970's vintage, and as such lacks modern day technology and functionality. Modern day technology deployment at the transformer station supports Renewable Generation Enabling Improvement objectives, as well as Smart Grid Directive objectives.

To date, FFPC has not received formal notice advising of the RIP communication plan or the preliminary schedule that is expected to be received by LDCs and part of the roll out. For planning purposes, Ontario has been divided into 21 regions by electrical topography. Regional plans for these 21 regions have been divided into three groups: Active (Group 1), Upcoming (Group 2) and Future (Group 3). It is worth noting, that FFPC's licensed

service territory is geographically located in “Active - Group 1”, which is said to have planning activities underway for some or all parts of the region. Refer to Appendix 2 for a map of the regions, as well as for a listing of electrical distributors within them.

To date, joint regional planning meetings involving FFPC, OPA, Regional Transmitter and other stakeholders have not yet transpired. As such, FFPC is not aware of any deliverables to comment on or to act upon at this time. FFPC has; however, been informed by the OPA from its Letter of Comment, that an East-West Transmission Tie Line project is proposed with an in-service date of 2017/2018. The proposed in-service date falls within FFPC’s 2014 to 2018 planning horizon, and aligns well with FFPC’s planned REG activities.

Although joint regional planning activities have not yet formally transpired, FFPC has solicited feedback from stakeholders including the Ontario Power Authority, regionally interconnected transmitters/distributor, municipal planning office, customers and the general public for the purpose of developing this DS Plan, as well as to fulfill rate application filing requirements. FFPC has incorporated stakeholder feedback and has attempted to align future service offerings and investments with the needs and priorities of all stakeholders, including consumers.

5.2.2.2 Consultations with the Ontario Power Authority

On July 12, 2013, FFPC submitted a formal "Request for Letter of Comment" to the OPA along with supporting documentation as per the criteria contained in Sections 5.1.4.1 and 5.1.4.2 of the revised OEB Chapter 5 Filing Requirements. The submission also included: a detailed description of FFPC's Planned Renewable Generation Enabling Improvements for period 2012 through 2018; a system capability assessment for renewable generation; smart grid deployment information; and regional planning and consultation activities. The following list depicts the table of contents of the information provided to the OPA to coordinate planning and to solicit comments:

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In its submission to the OPA, FFPC detailed its planned REG expenditures over the 2012 to 2018 planning horizon. The purpose of the planned expenditures is to modernize transformer station Fort Frances MTS' functionality, specifically improved protection, control and oversight, such that reverse power flow can be safely accommodated. The improvements will also significantly increase FFPC's renewable generation connection capacity, as well as they accomplish several Smart Grid directive objectives.

It is important to note that the OPA found FFPC's plan to modify its station protection and controls over a seven year period to be consistent with the schedule of potential transmission improvements in the region. Furthermore, OPA found that FFPC's plan is consistent with its information regarding renewable generation applications to date.

The OPA's August 30th, 2013 Letter of Comment is included as Appendix 1 of this submission.

5.2.2.2.a. October 17th, 2013 Announcement re Northwest Region Capacity Constraints Lifted

On October 17th, 2013, FFPC was personally contacted by the OPA, to advise of a new development since the issuance of its Letter of Comment. The OPA informed FFPC that the Northwest Region is no longer considered to be "Transmission Capacity Constrained", and that an additional 10 MW of renewable generation capacity has been allocated to the region. FFPC's service territory is very conducive to hosting renewable generation, as opposed to much of the outlying rural territory. FFPC expects considerable additional generators to connect to its distribution system over the forecast period. Based on current uptake levels, FFPC anticipates that an additional 312kW of capacity will come online between 2014 and 2018. Several Relocation Program applicants have also contacted FFPC to inquire about relocating their projects to within FFPC's service territory. The capacities of the relocation applicants total 360 kW. To date, construction has begun on two relocated projects (20 kW).

5.2.2.3 Consultations with Regionally Interconnected Distributors and Transmitters

FFPC does not have any regionally interconnected distributors (host or embedded) and is transmission connected to Hydro One Network Inc (HONI). Prior to the revised Chapter 5 Consolidated Distribution System Plan Filing Requirements coming into effect, FFPC was providing HONI with annual submissions regarding planned transformer station power outages, load forecasts, and renewable generation connection information.

In the past, these submissions were sent in the format and timeframe as requested by HONI. Outside of these formal submissions, FFPC has also worked very closely with HONI to coordinate mutual transformer station equipment outages necessary to conduct maintenance and capital work. The coordination of equipment outages effectively minimized the number and duration power interruptions that customers experience.

On July 12, 2013, FFPC also submitted a formal "Request for Letter of Comment" to HONI. Under the new regional planning process that has been developed by the Process Planning Working Group, FFPC expects to receive either a Needs Assessment Report, if FFPC involvement is not required in the RIP and/or IRRP process, or

alternately a Regional Planning Status Letter, if FFPC involvement is required in RIP and/or IRRP process. FFPC also welcomed any general feedback or comments for consideration. The following table of contents represents the information contained in FFPC's submission to HONI.

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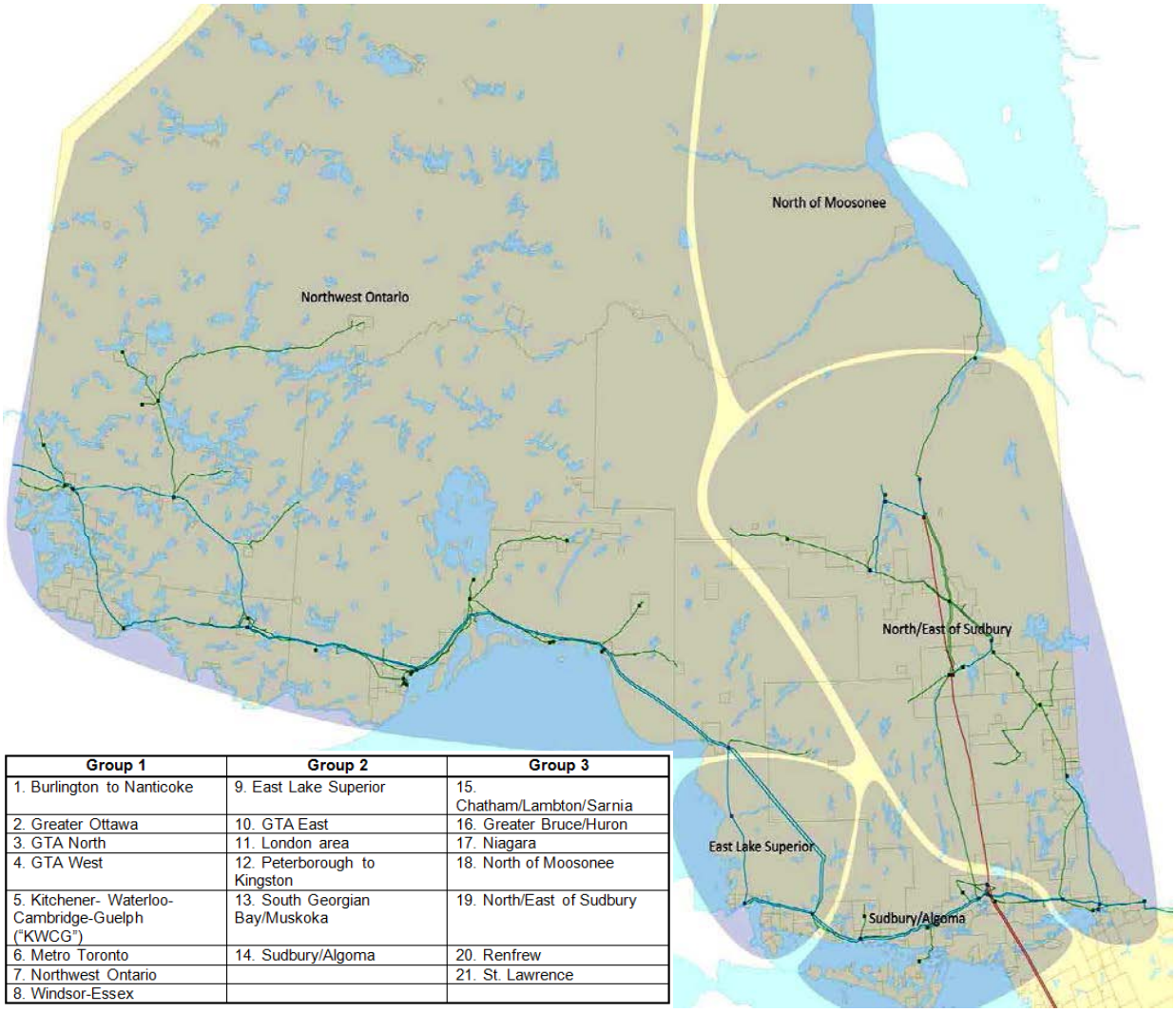
On October 21, 2013 FFPC received a Planning Status Letter in response to FFPC's request for a Letter of Comment.

5.2.2.3.a. October 21, 2013 Planning Status Letter

On October 21, 2013 FFPC received a Regional Planning Status Letter from HONI by way of email. The letter confirmed that FFPC's licensed distribution service territory belongs to "Group 1", which is the Northwest Region. The following map illustrates the 21 Regions/Groups that have been established throughout Ontario, based on electrical topology. The letter confirmed that the OPA is planning on reinforcing the transmission system in the region, north of Dryden, as well as along the East-West-Tie line. These initiatives are aligned with FFPC's planned renewable enabling improvements that will increase FFPC's generation connection capacity from 1.3 MW to 10.6 MW by 2018. The letter also informed FFPC that HONI and OPA are in the early stages of discussions with respect to coordinated regional planning. HONI proceeded to confirm that the formal regional planning process has not yet been initiated, nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the Northwest region affecting FFPC. Formal regional planning efforts are expected to commence in the first quarter of 2014. As such, FFPC is not aware of any deliverables at this time, and has not allocated any funding towards them at this time. Refer to Appendix 2 for HONI's Planning Status Letter

Group 1 - Northwestern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

5.2.2.4 Consultations with Customers

Customer focus is considered to be an important outcome of the OEB's newly released Renewed Regulatory Framework for Electricity. FFPC has incorporated customer feedback in developing its five-year DS Plan and beyond. Customer feedback is also a key input into FFPC's asset management process. Information gathered from customer surveys and other feedback forums were used to align FFPC's planned service offerings and planned expenditures with customer preferences and priorities.

FFPC conducted an extensive customer survey throughout the summer of 2013, to solicit customer feedback. A survey was mailed out to all of FFPC's customers in all rate classes via a bill insert. This approach gave all customers the equal opportunity to participate in the survey. To support this initiative, FFPC also launched an extensive newspaper advertising campaign to encourage all customers to participate in the survey.

The survey was broken down into the following sections by focus area:

- Customer satisfaction with FFPC
    - Overall; with the reliability of electricity supplied; with the portfolio of CDM program offerings; communication of planned power outages; responding to power outages; amount of time taken to restore power; ability to respond to questions; communicating when power will be restored; communicating outage causes
- Customer experiences with FFPC power outages
    - How long outages last; causes of outages; impact of outages on customer and customer's family; specific areas of concern during power outages (i.e. security, how long food lasts etc.)
- Customer Reliability Expectations
    - Expected number of unplanned outages; how many hours a year customers expect to be without electricity
- Customer Future Needs
    - Customer plans regarding the purchase of electric vehicles; customer plans regarding the installation of renewable generation; customer plans regarding the installation of energy storage systems;
- Customer Preferred Service Offerings
    - Online access to customer billing and detailed consumption data; automated customer notification system (i.e. automatic notification of planned power outages etc); electronic billing versus paper billing; true calendar month billing (billing based on consumption from first day to last day of month)
    - What specific things can FFPC improve on to serve customers better
- Customer Concerns
    - What is the most important energy or electricity related issue for consumers
- Customer Education
    - What topics do customers want to learn more about, such as conservation and demand management, understanding electricity bills, smart grid, renewable generation, smart meters etc.
- General Comments

FFPC's survey was very well received and almost 10% of the entire customer base completed and returned surveys. FFPC is pleased with the survey results, which found that customers are very pleased with FFPC's performance overall. It is worth noting that under the "Overall Satisfaction" portion of the survey, only 1 out of 345 responses received, indicated a degree of dissatisfaction.

Based on the survey findings, FFPC is planning on implementing the following projects over the 2014 to 2018 planning horizon.

1 - Mass customer contact system (outage notification etc): 2015 Rollout
2 - Outage Management System (outage alerts & customer communications): 2017 Rollout
2 - Transition to true calendar monthly billing: 2014 Rollout
3 - Offering a choice of Paper or Electronic Billing: 2014 Rollout
4 - Online access to consumption and billing data: 2014 Rollout
5 - Maintain distribution system reliability and performance by replacing end of life assets, in accordance to FFPC's asset management and capital planning processes : Ongoing

FFPC will also be launching annual customer education campaigns, which focus on topics consumers are most interested in learning more about. FFPC's customers want to learn more about the following topics in the following order of popularity: Conservation, Renewable Generation, Smart Meters, Smart Grid, Understanding Your Bill, Demand Management and Time-of-Use Rates.

FFPC plans on utilizing Town Hall Meetings, trade shows and standard advertising outlets such as newspapers and bill inserts. Furthermore, FFPC will be contacting customers personally to answer customer specific questions collected from the survey.

5.2.2.5 Consultations with Municipal Planning Office

FFPC has historically worked very closely with its Municipal Planning Office, in regards to coordinating planning efforts that are conducted throughout the community. FFPC will continue to work closely with its Municipal Planning Office, to coordinate the rollout of each other's projects. For example, FFPC provides feedback on all applications that are circulated to stakeholders from the municipal Committee of Adjustment. Comments are often solicited in regards to the impact of zoning changes, coordination of land utility services (electric, water, gas, sewer, communication), requests for relief from by-law requirements, easements etc. FFPC also uses the opportunity to advise applicants of their requirements under FFPC's Conditions of Service, as well as to inform applicants of relevant industry programs such as the "New Construction" CDM program offering.

In 2013, FFPC performed its first distribution feeder expansion in recent history. The underground feeder expansion was required to accommodate the development of a small fourteen lot subdivision.

FFPC is currently not aware of any significant development projects being coordinated through the Municipal Planning Office over the 2014 to 2018 planning horizon. As such, FFPC is not aware of any material impact that municipal development will have on the 2014 to 2018 DS Plan.

5.2.2.6 Fort Frances Emergency Control Group

FFPC is also an active member of the Fort Frances Emergency Control Group. The group performs emergency management table top exercises in preparation for real life community emergencies that may occur. Recent exercise scenarios included an ice storm, emergency evacuation due to an industrial site disaster, "Swine Flu" epidemic as well other natural disasters. The group also coordinates and conducts emergency management training for all members (key contacts) such as Incident Management Training (IMS). The table top emergency exercises are a good opportunity for members to review and critique their emergency plan.

Current members include FFPC, Ontario Provincial Police, Canadian Red Cross, Riverside Health Care (Regional Hospital), Ambulance Services, Corporation of the Town of Fort Frances, Victims Services, B93 (Local Radio Station), Ministry of Natural Resources, Resolute Forrest Products, Rainy River District Social Services Administration Services Board, Local Health Unit, Critical Incident Stress Management Team (C.I.S.M.), CN Railway, Union Gas, Energy Fundamental Group, and Treaty Three Police.

In recent history, this working group has stimulated FFPC to proactively prepare itself for emergency situations. In 2009, FFPC invested in a back-up generator for its main office, such that essential services can remain operational including communications, building heat and lighting. In 2011, FFPC also equipped its operations centre with a backup generator, to also allow for essential building services to remain operational such as communications, building heat and lighting. FFPC's offices are now deemed to be suitable locations for alternate Emergency Operation Centres in the event of a community or regional crisis.

FFPC has several immaterial initiatives planned over the 2014 to 2018 planning horizon that are driven from this consultation, such as staff education and awareness training; however, the costs are expected to be immaterial.

5.2.2.7 Letters of Comment

To date, FFPC has received formal letter of comment from the OPA, as well as Hydro One Networks Inc. The OPA Letter of Comment with respect to FFPC's DS Plan has been attached to this submission as Appendix 1. HONI's Letter of Comment with respect to FFPC's DS Plan has been attached to this submission as Appendix 2.

5.2.2.8 Impact Summary of Third Party Consultations on DS Plan

The following in a summary of material impacts on FFPC's 2014 to 2018 DS Plan, as a result of third party and stakeholder consultations:

Regional Planning Consultations

- Currently there are no confirmed deliverables identified as formal consultations have not yet begun
- Potential East-West Tie Line Transmission project may impact FFPC DS Plan, but at this point in time the potential impact cannot be quantified
- No quantifiable impact available at the time of preparing this DS Plan

Consultation with OPA

- OPA finds FFPC's planned Renewable Enabling Improvements at transformer station Fort Frances MTS to align with the potential transmission improvements for the region
- The OPA advised FFPC of an additional 10 MW of renewable generation capacity for the Northwest region, which implies continued FIT and microFIT uptake in FFPC's service territory over the 2014 to 2018 planning period.

Customer Engagement - Customer Satisfaction Survey Findings

- Customers find that investing in a Mass Customer contact system will be of value to their needs
    - FFPC planning on deploying mass customer contact system in 2015
        - Estimated Capital Cost $15,000
- Customers find that investing in transitioning customer billing to true calendar month billing will be of value to their needs
    - FFPC planning on deploying true calendar monthly billing in 2014
        - Estimated Operational Cost $7,500
- Customers find that investing in offering a choice of receiving a paper or electronic bill will be of value to their needs
    - FFPC planning on deploying paper or electronic billing choice in 2014
        - Estimated Operational Cost $10,000
- Customers don't find that investing in technology to enable them to access their electronic consumption data and billing information through the internet is of value to their needs
    - FFPC recognizes that this is a mandated directive, and as such FFPC will proceed with offering online access to consumption and billing data in 2014
        - Estimated Operational Cost $10,000
- Outage Communication is an identified area of improvement, FFPC plans to deploy an Outage Management System (OMS) that will enable proactive notification of localized customer outages, as well as assist with customer communication and interaction regarding planned or unplanned outages
    - FFPC planning to deploy an OMS in 2017
        - Estimated Capital Cost $43,000

Consultations with Municipal Planning Office

- There are no significant projects planned under this consultation during the period 2014 to 2018.
- As such, FFPC is not aware of any corresponding material impact on its 2014 to 2018 DS Plan based on this consultation

Consultations with Emergency Control Group

- This consultation has not had a material impact on FFPC's 2014 to 2018 DS Plan, with respect to demanding capital expenditures.

5.2.3 Performance measurement for continuous improvement

5.2.3.1 Overview of Performance Metrics

FFPC has historically used its own set of Key Performance Indexes (KPI's) to measure various aspects of performance. Many of these KPI's are aligned with measures contained in the Board's RRR filing requirements, as well as with the Board Staff's July 2013 recommended scorecard. FFPC also utilizes several performance measures which it believes to be of importance, that are not currently used by the Board. FFPC has identified and defined these measures, as well as provided performance results with respect to them.

FFPC's mission is to deliver safe and reliable electricity to its customers, at the lowest possible sustainable rates. FFPC has attempted to align its performance measures with the July 2013 version of Board Staff's Recommended LDC scorecard. FFPC currently does not use all of the recommended measures, and as such, FFPC does not have a history of data for newly introduced measures. FFPC plans to adopt any new measures contained in the finalized scorecard.

5.2.3.2 FFPC RRR Unitized Statistics and Service Quality Requirements History

The following summary illustrates FFPC's Unitized Statistics and Service Quality Requirements history based on RRR reporting, for the period 2005 to 2012. Detailed discussions about significant measures, as per Board Staff's July 2013 recommended scorecard, are provided under sections 5.2.3.4 through 5.2.3.8.

Unitized Statistics and Service Quality Requirements	2005	2006	2007	2008	2009	2010	2011	2012
# of Customers per sq km of Service Area	155.38	153.12	148.62	153.88	144.92	145.27	145.19	145.38
# of Customers per km of Line	53.16	47.39	46.00	47.63	44.86	44.96	51.01	51.08
Ave. Power & Distribution Revenue less Cost of Power & Related Costs								
Per Customer Annually	$342.92	$424.31	$371.06	$397.29	$411.73	$417.41	$403.15	$484.20
Per Total kWh Purchased	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
Average Cost of Power & Related Costs								
Per Customer Annually	$1,523.85	$1,458.23	$1,594.13	$1,471.98	$1,674.33	$1,514.99	$1,639.16	$1,927.27
Per Total kWh Purchased	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.09
Avg Monthly kWh Consumed per Customer	1,805	1,807	1,891	1,823	1,905	1,854	1,833	1,767
Avg Peak (kW) per Customer	3.46	3.55	3.71	3.53	3.62	3.50	3.49	3.39
OM&A Per Customer	$263.58	$282.63	$296.59	$312.64	$349.41	$350.99	$344.90	$428.61
Net Income Per Customer	$4.76	$18.61	$14.50	-$4.29	-$15.30	$4.51	-$1.44	-$83.05
Net Fixed Assets per Customer	$ 833.68	$ 846.11	$ 819.25	$ 744.93	$ 772.17	$ 813.93	$ 760.42	$ 859.88
Service Quality Requirements								
Low Voltage Connections (OEB Min. Standard: 90%)	N/A	100	100	100	100	100	100	100
High Voltage Connections (OEB Min. Standard: 90%)	N/A	100	N/A	100	100	100	100	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	N/A	100	100	100	97.4	94	94.1	93.6
Appointments Met (OEB Min. Standard: 90%)	N/A	100	100	100	100	100	100	100
Written Response to Enquiries (OEB Min. Standard: 80%)	N/A	N/A	100	100	100	100	98	100
Emergency Urban Response (OEB Min. Standard: 80%)	N/A	100	100	100	100	100	100	100
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	N/A	N/A	N/A	N/A	3.1	2.8	5.1	2.2
Appointments Scheduling (OEB Min. Standard: 90%)	N/A	N/A	N/A	N/A	100	100	100	100
Rescheduling a Missed Appointment (OEB Standard: 100%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Reconnection Performance Standard (OEB Min. Standard: 85%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	100
Service Reliability Indices								
SAIDI-Annual	N/A	0.15	0.30	3.77	6.63	0.60	0.09	0.30
SAIFI-Annual	N/A	0.24	0.31	1.77	2.40	0.31	0.21	0.30
CAIDI-Annual	N/A	0.62	0.95	2.13	2.76	1.92	0.43	1.02
Loss of Supply Adjusted Service Reliability Indices								
SAIDI-Annual	N/A	N/A	N/A	N/A	N/A	0.60	0.09	0.3

SAIFI-Annual	N/A	N/A	N/A	N/A	N/A	0.31	0.21	0.3
CAIDI-Annual	N/A	N/A	N/A	N/A	N/A	1.92	0.43	1.02

5.2.3.3 FFPC RRR Financial Ratio History

The following summary illustrates FFPC's financial ratio history based on RRR reporting, for period 2005 to 2012. Detailed discussions about significant measures as per Board Staff's July 2013 recommended scorecard are provided under section 5.2.3.8

	RRR Reported Financial Ratios	2005	2006	2007	2008	2009	2010	2011	2012
Liquidity Ratios	Current Ratio (Current Assets/Current Liabilities)	3.50	4.65	4.82	3.96	3.30	4.11	4.97	2.67
Leverage Ratios	Debt Ratio (Total Debt/Total Assets)	0%	0%	0%	0%	0%	0%	0%	0.00
	Debt to Equity Ratio (Total Debt/Total Equity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Interest Coverage (EBIT/Interest Charges)	14.58	38.58	49.53	-0.84	0.68	2.19	0.68	-8.95
Profitability Ratios	Financial Statement Return on Assets (Net Income/Total Assets)	0.24%	1.10%	0.82%	-0.24%	-0.84%	0.19%	-0.07%	-3.78%
	Financial Statement Return on Equity (Net Income/Shareholder Equity)	0.34%	1.28%	0.96%	-0.29%	-1.03%	0.30%	-0.10%	-5.93%

5.2.3.4 Customer Focus Measures

FFPC has divided customer focus measures into the following two main performance categories; Service Quality and Customer Satisfaction. FFPC's service quality measures are based mainly on statistics reported in RRR filings; however, as of 2013 FFPC has also been able to incorporate the results of its first customer satisfaction survey.

5.2.3.4.a. Connection of LV Services

FFPC does not experience a large volume of requests for new connections, which is a good reflection of the local economy, which is regressing somewhat. FFPC is able to offer excellent customer service with respect to responding to customer service requests. Most requests for connection of a new service are accommodated within one business day, well above the minimum requirement of five days. In 2013, FFPC only received three (3) requests to connect new low voltage services. Throughout 2013 no requests to connect new high voltage services were received.

5.2.3.4.a.i. OEB Requirement

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.

5.2.3.4.a.ii. OEB Approved Standard

At least 90% on a yearly basis

5.2.3.4.a.iii. Performance History

Connection of New Services – Low Voltage		
Year	Minimum Standard	FFPC Performance
2008	90%	100%
2009	90%	100%
2010	90%	100%
2011	90%	100%
2012	90%	100%

5.2.3.4.a.iv. Performance Trend & Assessment

FFPC consistently exceeds OEB requirements, and as such is satisfied with its performance. This measure is not identified as having a material impact on FFPC's 2014 - 2018 DS Plan.

5.2.3.4.b. Appointment Scheduling

The majority of appointments are scheduled and attended to by FFPC's General Superintendent. FFPC has a relatively small service territory, which does not require long travel distances and essentially any customer destination can be reached within a fifteen minute window. Furthermore, as Fort Frances is a relatively small community, travel delays such as those due to rush-hour traffic are nonexistent. As such, FFPC has an excellent track record scheduling and attending appointments as required. Many appointments are scheduled and attended to within one day of receiving the customer request.

5.2.3.4.b.i. OEB Requirement

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code.

5.2.3.4.b.ii. OEB Approved Standard

At least 90% on a yearly basis

5.2.3.4.b.iii. FFPC Performance History

Appointment Scheduling		
Year	Minimum Standard	FFPC Performance
2008	90%	n/a
2009	90%	100%
2010	90%	100%
2011	90%	100%
2012	90%	100%

5.2.3.4.b.iv. Performance Trend & Assessment

FFPC consistently exceeds OEB requirements, and as such is satisfied with its performance. This measure is not identified as having a material impact on FFPC's 2014 - 2018 DS Plan.

5.2.3.4.c. Appointment Met

As per the same reasons discussed under appointment scheduling, FFPC has an excellent track record meeting appointment obligations.

5.2.3.4.c.i. OEB Requirement

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.

5.2.3.4.c.ii. OEB Approved Standard

At least 90% on a yearly basis.

5.2.3.4.c.iii. FFPC Performance History

Appointments Met		
Year	Minimum Standard	FFPC Performance
2008	90%	100%
2009	90%	100%
2010	90%	100%
2011	90%	100%
2012	90%	100%

5.2.3.4.c.iv. Performance Trend & Assessment

FFPC consistently exceeds OEB requirements, and as such is satisfied with its performance. This measure is not identified as having a material impact on FFPC's 2014 - 2018 DS Plan.

5.2.3.4.d. Telephone Accessibility

FFPC is currently in the process of reconfiguring its telephone system to address functionality limitations. FFPC typically experiences a relatively low volume of customer calls; however, FFPC is currently limited to only being able to answer one "outside" call at a time. All incoming calls are currently directed to and answered by FFPC's Administrative Assistant. Unanswered calls are routed to a voice mail system. A system reconfiguration will expand the bottleneck of one outside line, to a recommended three. This will enable simultaneous telephone calls to be answered by other available staff members.

The current telephone system is unable to track and calculate statistical information such telephone call abandon rates, or the length of time that a call in a queue. Telephone statistics are currently being logged and computed manually, which is an onerous process. Abandon rates are not directly available and as such are

currently calculated as a function of voice mail messages. The assumption is that during regular business hours a voice mail is a telephone call that was abandoned.

FFPC believes that telephone accessibility with respect to hosting multiple incoming call lines, as well as automated statistical reporting for regulatory reporting purposes is in an area requiring improvement. FFPC will be expanding its incoming phone pipe from one to three lines. A telephone system upgrade enabling automatic statistical reporting has been identified as a strategic improvement project in FFPC's five year business plan.

5.2.3.4.d.i. OEB Requirement

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.

5.2.3.4.d.ii. OEB Approved Standard

At least 65% on a yearly basis.

5.2.3.4.d.iii. FFPC Performance History

Telephone Accessibility		
Year	Minimum Standard	FFPC Performance
2008	65%	100.0%
2009	65%	97.4%
2010	65%	94.0%
2011	65%	94.1%
2012	65%	93.6%

5.2.3.4.d.iv. Performance Trend

FFPC exceeds OEB requirements; however, FFPC is not satisfied with how telephone performance metrics are currently calculated, due to telephone system limitations. Although FFPC is pleased with its service level, a telephone system upgrade has been identified as a strategic improvement to satisfy regulatory reporting obligations. This measure is identified as having a small impact on FFPC's 2014 - 2018 DS Plan. FFPC requires a $20,000 capital investment to improve reporting telephone performance metrics.

5.2.3.5 Customer Satisfaction

Over the summer of 2013, FFPC conducted its first customer satisfaction survey. The survey provided both quantitative and qualitative measures of customer satisfaction. The complete results of the survey are attached as Appendix 3, and the sections pertaining specifically to customer satisfaction are discussed below.

5.2.3.5.a. Customer Satisfaction Survey

The following table illustrates the questions that customers were asked, the scoring legend, as well as FFPC's corresponding survey score. A portion of the customer survey management response is also provided following the tables.

		Scoring Legend			FFPC Score		
		Scoring Range From 1 to 10			Scoring Range From 1 to 10		
		Not At All Satisfied	Neither Satisfied or Dissatisfied	Extremely Satisfied	Average	Median	Mode
1	Overall, how satisfied are you with the services provided by the Fort Frances Power Corporation (FFPC)?	1	5	10	9.0	10.0	10.0
2	How satisfied are you with the reliability of the electricity supplied to you overall?	1	5	10	9.5	10.0	10.0
3	How satisfied are you with the portfolio of conservation programs that are currently offered to you?	1	5	10	7.8	10.0	10.0
4	How satisfied are you with how FFPC communicates planned outages to you?	1	5	10	8.8	10.0	10.0
5	Now thinking specifically about unplanned outages, how satisfied are you with FFPC:						
	a. Responding to power outages, overall?	1	5	10	9.3	10.0	10.0
	b. Amount of time taken to restore power?	1	5	10	9.1	10.0	10.0
	c. Ability to respond to questions?	1	5	10	8.0	10.0	10.0
	d. Communication when power will be restored?	1	5	10	7.7	9.5	10.0
	e. Communication why an outage occurred?	1	5	10	7.6	10.0	10.0
		Scoring Legend			FFPC Score		
6	Thinking of recent power outages that you have experienced:	Answer in Minutes			Average Minutes	Median Minutes	Mode Minutes
	a. On average, for how many minutes do power outages last?	X Minutes			25.0	15.0	30.0

5.2.3.5.a.i. Overall Customer Satisfaction

Customers are overall very satisfied with the services provided by FFPC, as indicated by the average score of 9.0 out of 10, where 10 represents extremely satisfied. It is worth noting that only one customer response out of 345 received, indicated a degree of dissatisfaction.

5.2.3.5.a.ii. Reliability of Electricity Supplied

Customers are overall very satisfied with the reliability of electricity supplied, as indicated by an average score of 9.5 out of 10, where 10 represents extremely satisfied. Management recommends continuing with its current practices towards maintaining electrical distribution system reliability.

5.2.3.5.a.iii. Conservation Program Offerings

Customers are moderately satisfied with the portfolio of conservation programs that are being offered, as indicated by an average score of 7.8 out of 10, where 10 represents extremely satisfied. Conservation program offerings appear to be an area of opportunity for improvement. Management recommends exploring the feasibility of enhancing CDM programs to have a "Northern Element" in them, specifically related to targeting reductions in heating loads. Northern residents require significantly more heating than cooling due to the colder climate. A 2012 comparison of the temperature at the Fort Frances Airport versus Lester B. Pierson Airport indicates that consumers in Fort Frances are subjected to 55% more Heating Degree Day (HDD) demand over a year, at 4976 versus 3215 in Toronto.

5.2.3.5.a.iv. Communicating Planned Outages

Customers are very satisfied with how FFPC communicates planned outages, as indicated by an average score of 8.8 out of 10, where 10 represents extremely satisfied. Management recommends continuing with its current practice of announcing planned outages.

5.2.3.5.a.v. Satisfaction with Unplanned Outages

Overall customers are very satisfied with how FFPC responds to power outages overall; with the amount of time taken to restore power; and with FFPC's ability to respond to questions. FFPC received scores of 9.3, 9.1 and 8.0 out of 10 respectively, where 10 represents extremely satisfied. Customers are moderately satisfied with FFPC's communication of when power will be restored, and with FFPC's communication of why an outage occurred, as indicated by average scores of 7.7 and 7.6 out of 10 respectively, where 10 represents extremely satisfied. Management recommends that although customers are moderately to very satisfied, an opportunity exists to improve customer communication, specifically customer outages.

5.2.3.5.a.vi. General Comments

The general comments portion of the survey also demonstrates the high degree of customer satisfaction, with 73.6% (123 general comments out of a possible 169 general comments received) of all general comments received being compliments towards FFPC.

5.2.3.5.a.vii. Performance Trend & Assessment

FFPC currently does not have any performance trends regarding the level of customer satisfaction. FFPC is pleased with the current level of customer satisfaction; however, the survey identified opportunities

for improvement. The customer survey results have impacted FFPC's 2014 to 2018 DS Plan. FFPC will be initiating the following Customer Focus projects over the 2014 to 2018 planning horizon:

- Customers find that investing in Mass Customer contact system will be of value to their needs
    - FFPC is planning on deploying mass customer contact system in 2015
        - Estimated Capital Cost $15,000
    - FFPC is planning on deploying Outage Management System to complement mass customer contact system in 2017
        - Estimated Capital Cost $43,000
- Customers find that investing in transitioning customer billing to true calendar month billing will be of value to their needs
    - FFPC is planning on deploying true calendar monthly billing in 2014
        - Estimated Operational Cost $7,500
- Customers find that investing in offering a choice of receiving paper or electronic bills will be of value to their needs
    - FFPC is planning on deploying paper or electronic billing choice in 2014
        - Estimated Capital Cost $10,000
- Customers don't find that investing in technology to enable them to access their electronic consumption data and billing information through the internet is of value to their needs
    - FFPC recognizes that this is a mandated directive, and as such will proceed with offering online access to consumption and billing data in 2014
        - Estimated Capital Cost $10,000
- FFPC is planning on adding a new position of "Technical Customer Service Representative" to its organization. The position will primarily be responsible for engaging customers and to deliver customer preference related projects and services. Another core role of the new position will be to support FFPC's long range planning activities, by assisting in the annual processing of the newly developed Asset Management Planning and Capital Planning Processes. FFPC anticipates that the position will increase FFPC's OM&A expenses by $76,000 for labour expenses, and $26,000 for benefit related expenses. For the 2014 test year, FFPC expects these expenses to be ½ ($51,000) to reflect a hiring/starting date of July 1, 2014.

5.2.3.6 Operational Effectiveness Measures

FFPC has divided its operational effectiveness measures into three categories; Safety, System Reliability and Overall Cost Performance. This DS Plan contains FFPC's first formal asset management plan (process), and as such no historic performance levels are available.

5.2.3.6.a. Safety

5.2.3.6.a.i. ESA Ontario Regulation 22/04 Compliance Audits

In early 2004, Ontario Regulation 22/04 was put in place with the objective of enhancing public safety in regards to Ontario's electrical distribution systems. The regulation affects the safety requirements for

the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Section 13 of the regulation stipulates that distributors are required to participate in annual compliance audits as per the following:

> *13. (1) It is a condition of an approval issued to a distributor for the use of a distribution system that the distributor engage an auditor to audit on an annual basis the distributor's compliance with sections 4, 5, 6, 7 and 8 and to prepare an audit report. O. Reg. 22/04, s. 13 (1).*

As such, FFPC has participated in annual compliance audits and believes that the audit results are a good measure for assessing performance with respect to ensuring public and employee safety.

5.2.3.6.a.i.1 Objective and Scope of the Audit:

To conduct a comprehensive review of the processes, guidelines, and standards used by Fort Frances Power Corporation (FFPC) in their designs, construction, installations, use, maintenance and repairs, extensions, connections and disconnections of electrical equipment forming the distribution system as to avoid or reduce the possibility of electrical hazards.

5.2.3.6.a.i.2 Auditing Methodology followed:

The following standard audit practices were followed to assess the level of conformance to the provincial safety regulation:

1. Review of Fort Frances Power Corporation's existing processes, guidelines and standards.
2. In person meeting with knowledgeable personnel.
3. Site visits.

5.2.3.6.a.i.3 Section 4: Safety Standards

Section 4.0 of Regulation 22/04 (Electrical Distribution Safety) requires that the distributor has processes in place to ensure that all distribution systems and the electrical installations, and electrical equipment forming part of such systems are designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to avoid/reduce the exposure to electrical safety hazards.

5.2.3.6.a.i.4 Section 5: When Safety Standards Met

To meet the requirements of Section 5.0 of Regulation 22/04 (Electrical Distribution Safety), the distributor is to ensure that there are processes in place that check on an ongoing basis the installations, overhead and underground lines and distribution stations.

5.2.3.6.a.i.5 Section 6: Equipment Approval

Section 6 of Regulation 22/04 requires the use of certified/duly approved equipment for the construction of new or the repair and extension of existing distribution systems after February 11, 2005.

5.2.3.6.a.i.6 Section 7: Approval of plans, drawings, and specifications for installation work

Section 7.0 of Regulation 22/04 (Electrical Distribution Safety) applies to electrical installations that are, or may form part of the distribution system. This section requires that before starting, or affecting

repairs, alterations, or extensions of an existing distribution system, the distributor must ensure that the installation is based on:

- Plans that have been prepared by a Professional Engineer and these have been reviewed and approved by a professional engineer or ESA; or
- The distributor's standard design drawings are assembled by a Professional Engineer or by an engineering technologist certified by OACETT, or by another competent person, and reviewed and approved by a professional engineer or by ESA.
- Moreover, prior to authorizing third party attachments, the distributor is to ensure that attachments to its distribution systems meet the safety requirements of the Regulation

5.2.3.6.a.i.7 Section 8: Construction Approval and Inspections

On February 11, 2005, section 8 of the Regulation came into effect requiring that before putting any new construction or repairs of the distribution systems into use, the distributor is to:

- ensure the construction is inspected;
- confirm that only approved equipment was utilized in the construction;
- prepare a record of inspection; and
- complete a Certificate

5.2.3.6.a.i.8 FFPC Performance History

FFPC Ontario Regulation 22/04 Compliance Audit Results					
Audit Year	Section 4 Safety Standards	Section 5 When Safety Standards Met	Section 6 Equipment Approval	Section 7 Approval of plans, drawings, and specifications for installation work	Section 8 Construction Approval and Inspections
2008	C	C	C	NI	NC
2009	C	C	C	NI	NI
2010	C	C	C	C	C
2011	C	C	C	C	C
2012	C	C	C	C	C
Legend C-complies, NI- Needs Improvement Identified, NC Non-conformance found, N/A –Not Applicable					

5.2.3.6.a.i.9 Performance Trend & Assessment

FFPC is very pleased with its performance record and notes over the last five years only once instance of a non-conformance to regulation 22/04 was identified through the audit process. FFPC has managed to obtain a perfect score for the last three consecutive years. Compliance to O.Reg. 22/04 has not been identified as needing improvement or as a driver requiring material investments over the planning period. FFPC's objective is to maintain current performance levels.

5.2.3.6.a.ii. ESA Due Diligence Inspections

In order to ensure compliance with Ontario Regulation 22/04 "Electrical Distribution Safety", the Electrical Safety Authority performs Due Diligence Inspections (DDIs) of LDCs. The inspections focus on ensuring that construction in the field is in accordance with a plan, work instruction, and/or standard designs such that no undue hazards exist to the public or LDC personnel. FFPC believes this measure to be a good measure of performance with respect to public safety and the safety of personnel.

LDCs receive an inspection report which could require LDC action in the event that significant findings were found in the inspection. Findings are classified according to their importance with respect to safety in the following order of importance:

1. Imminent Fire / Shock / Explosion Hazards
2. Non-Compliance(s) to O.Reg. 22/04
3. Needs Improvement
4. Safety Related Observations
5. Miscellaneous Observations

The following are ESA's definitions and instructions with respect to responding to the DDI Inspection Report:

5.2.3.6.a.ii.1 Imminent Fire/Shock/Explosion Hazard

This section details imminent fire/shock/explosion hazards. All items listed under this section need to be addressed immediately by the Local Distribution Company (LDC) and a formal, written response submitted to Electrical Safety Authority (ESA).

5.2.3.6.a.ii.2 Key Due Diligence Findings

Key Due Diligence Findings are items that ESA requires formal, written responses within 10 working days. The Key Due Diligence Findings can be found in the "NON-COMPLIANCES TO REGULATION 22/04" and "NEEDS IMPROVEMENT" sections of the report.

5.2.3.6.a.ii.3 Observations

Observations are items that ESA does not require formal, written responses to, unless specifically requested. The Observations can be found in the "SAFETY RELATED OBSERVATIONS" and "MISCELLANEOUS OBSERVATIONS" sections of the report.

5.2.3.6.a.ii.4 Non-Compliances to Regulation 22/04

The section details non-compliances to Regulation 22/04. All items listed under this section need to be addressed by the Local Distribution Company (LDC) and a formal, written response submitted to Electrical Safety Authority (ESA). For each non-compliance detailed, the LDC shall address (1) an ACTION PLAN / RESPONSE and (2) TIMELINES (when not detailed by ESA) for addressing each non-compliance.

5.2.3.6.a.ii.5 Needs Improvement

The section details areas where improvements are required with respect to Regulation 22/04. All items listed under this section need to be addressed by the Local Distribution Company (LDC) and a formal, written response submitted to Electrical Safety Authority (ESA). For each "Needs Improvement" point,

the LDC shall address (1) an ACTION PLAN / RESPONSE and (2) TIMELINES (when not detailed by ESA) for addressing each point. LDC's are requested to provide comments within 10 working days.

5.2.3.6.a.ii.6 Safety Related Observations

The section details safety related observations discovered during the inspection. Items listed under this section do not require a response by the LDC, unless specifically requested by ESA. These observations affect the safety of the public or LDC personnel, and may or may not fall under Regulation 22/04.

5.2.3.6.a.ii.7 Miscellaneous Observations

The section details non-safety related observations discovered during the inspection. Items listed under this section do not require a response by the LDC, unless specifically requested by ESA. These observations are non-safety related, and may or may not fall under Regulation 22/04.

5.2.3.6.a.ii.8 FFPC Performance History

FFPC ESA Due Diligence Inspection Performance History					
Inspection Year	Imminent Fire / Shock / Explosion Hazards	Non-Compliances(s) to O.Reg. 22/04	Needs Improvement	Safety Related Observations	Miscellaneous Observations
2008	0	0	0	1	0
2009	0	0	3	2	2
2010	0	0	2	2	2
2011	0	0	0	3	3
2012	0	0	0	0	2

5.2.3.6.a.ii.9 Performance Trend

FFPC is very pleased with the inspection results and notes that over the last five years of inspections no hazards or non-conformances to Ontario Regulation 22/04 were found. FFPC was not required to prepare a formal response to the inspection findings three out of five years. DDI inspection performance is not identified as needing improvement or to be a driver requiring material investments over the planning period. FFPC's objective is to maintain current performance levels.

5.2.3.6.a.iii. Safe Worked Hours & Injury Free Years

FFPC has been tracking the performance of employee safety using the measure "Safe Worked Hours". This measure is a summation of all employee hours worked, beginning at zero, ending in the event that an employee suffers a lost time injury. A lost time injury refers to accidents or injuries that force the employee to remain away from his or her work, beyond the day of the accident or for the next shift. Similarly, FFPC also tracks the amount of time that has elapsed in the unit "years, months", since the last occurrence of a lost time injury.

5.2.3.6.a.iii.1 FFPC Performance History

FFPC's performance record as at August 31, 2013 is:

Safe Worked Hours - 71,576

Injury Free Years - 5 Years, 3 Months

5.2.3.6.a.iii.2 Performance Trend & Assessment

FFPC is pleased with its track record of employee safety. FFPC's last lost time injury occurred in May of 2008, due to an employee requiring surgery on a shoulder muscle due to a long term repetitive strain injury. In June of 2013, FFPC surpassed a five year injury free milestone, and currently has accumulated 71,576 safe worked hours as at the end of August 2013. FFPC is not aware of comparable industry statistics and as such no industry comparison is available. FFPC's objective is to continually improve its Health and Safety program. Over the 2014 to 2018 planning horizon, FFPC is planning on expanding employee safety awareness, skills development training and continued education. FFPC believes that all work related injuries can be prevented if employees are armed with the proper continued education and training, as well as supplied with the proper tools that enable them to work safely.

5.2.3.6.b. System Reliability and Performance

FFPC's measures to quantify the performance of its electrical distribution system are SAIDI, SAIFI, CAIDI, as well as the results obtained from an annual outage cause analysis.

5.2.3.6.b.i. SAIDI, SAIFI & CAIDI

FFPC has adopted the industry standard distribution system reliability measures SAIDI, SAIFI and CAIDI for assessing the performance of its electrical distribution system.

5.2.3.6.b.i.1 Definitions

SAIDI: System Average Interruption Duration Index (SAIDI) is defined as the length of outage customers experience in a year on average and it is expressed as hours per customer per year.

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

SAIFI: System Average Interruption Frequency Index is defined as the average number of interruptions each customer experiences and it is expressed as number of interruptions per year per customer

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

CAIDI: Customer Average Interruption Duration Index is defined as the speed at which power is restored and it is expressed as average duration in hours per customer per year.

$$\text{CAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

5.2.3.6.b.i.2 Significance of Loss of Supply

Loss of supply can have a significant impact on FFPC's overall reliability statistics, as FFPC's entire customer base is supplied from a single supply point. A loss of supply at this connection point results in all customers being without power, compared to localized issues that only affect a small number of customers. Thus, loss of supply by nature can be the dominant cause of poor distribution system performance.

5.2.3.6.b.i.3 Customer Expectations

FFPC conducted its first customer satisfaction survey over the summer of 2013. As part of the survey, consumers were asked specifically about their expectations with respect to how many hours they expect to be without electricity in a year and how many power outage incidents they expect to experience. The results were as per the following:

		Scoring Legend	FFPC Score		
		Number of Hours	Average Hours	Median Hours	Mode Hours
9	How many hours in a year do you expect to be without electricity?	X Hours	4.4	3.0	1.0

On average, FFPC's customers expect to be without electricity for a total of 4.4 hours according to the 2013 survey results.

		Scoring Legend	FFPC Score		
		Number of Instances	Average	Median	Mode
8	How many unplanned power outages do you expect to happen at your home in a typical year?	X Unplanned Outages	2.9	2.0	2.0

On average, customers expect to experience 2.9 unplanned outages in a year.

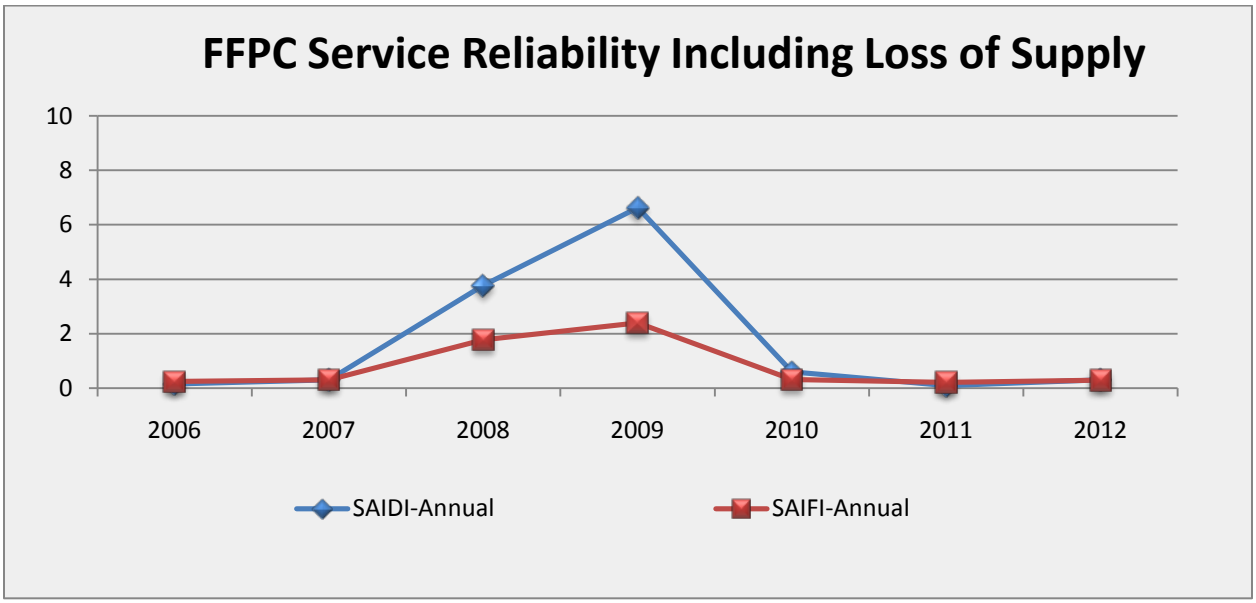
5.2.3.6.b.i.4 FFPC Performance History

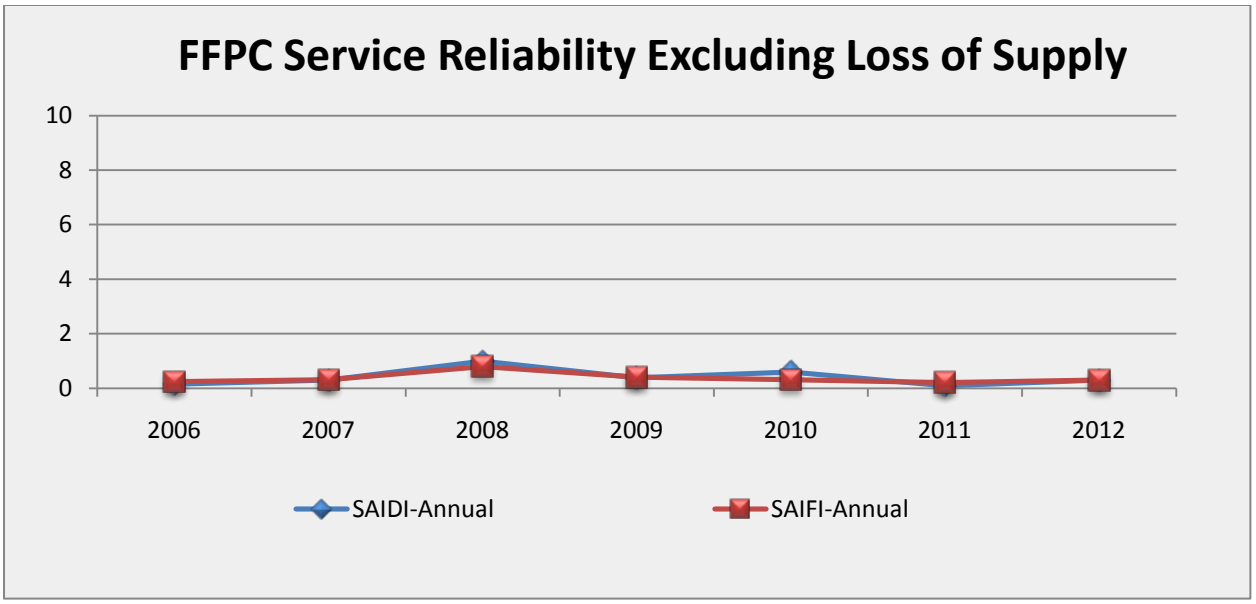
Service Reliability Indices Including Loss of Supply							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
SAIDI - Annual	0.15	0.30	3.77	6.63	0.60	0.09	0.30
SAIFI - Annual	0.24	0.31	1.77	2.40	0.31	0.21	0.30
CAIDI - Annual	0.62	0.95	2.13	2.76	1.92	0.43	1.02

Service Reliability Indices Adjusted for Loss of Supply							
	2006	2007	2008	2009	2010	2011	2012
SAIDI - Annual	0.15	0.30	0.99	0.38	0.60	0.09	0.30
SAIFI - Annual	0.24	0.31	0.79	0.40	0.31	0.21	0.30
CAIDI - Annual	0.62	0.95	1.25	0.96	1.92	0.43	1.02

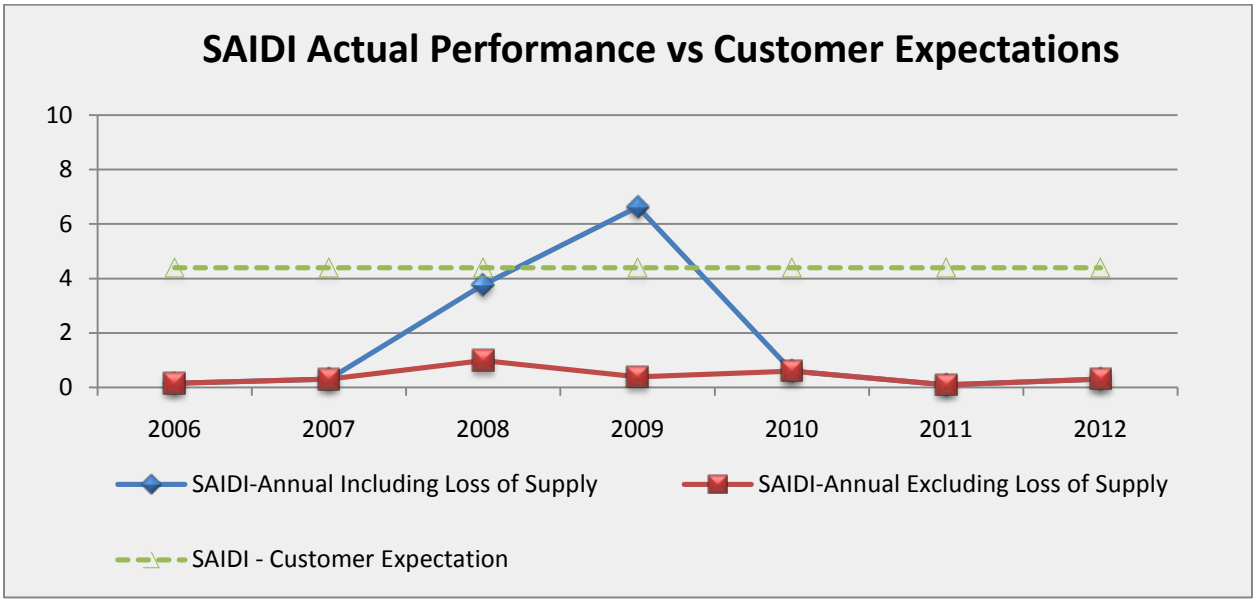
SAIDI Actual Performance vs Customer Expectations							
	2006	2007	2008	2009	2010	2011	2012
SAIDI - Annual With Loss of Supply	0.15	0.30	3.77	6.63	0.60	0.09	0.30
SAIDI - Annual Without Loss of Supply	0.15	0.30	0.99	0.38	0.60	0.09	0.30
SAIDI - Customer Expectation	4.40	4.40	4.40	4.40	4.40	4.40	4.40

SAIFI Actual Performance vs Customer Expectations							
	2006	2007	2008	2009	2010	2011	2012
SAIFI - Annual With Loss of Supply	0.24	0.31	1.77	2.40	0.31	0.21	0.30
SAIFI - Annual Without Loss of Supply	0.24	0.31	0.79	0.40	0.31	0.21	0.30
SAIFI - Customer Expectation	2.90	2.90	2.90	2.90	2.90	2.90	2.90

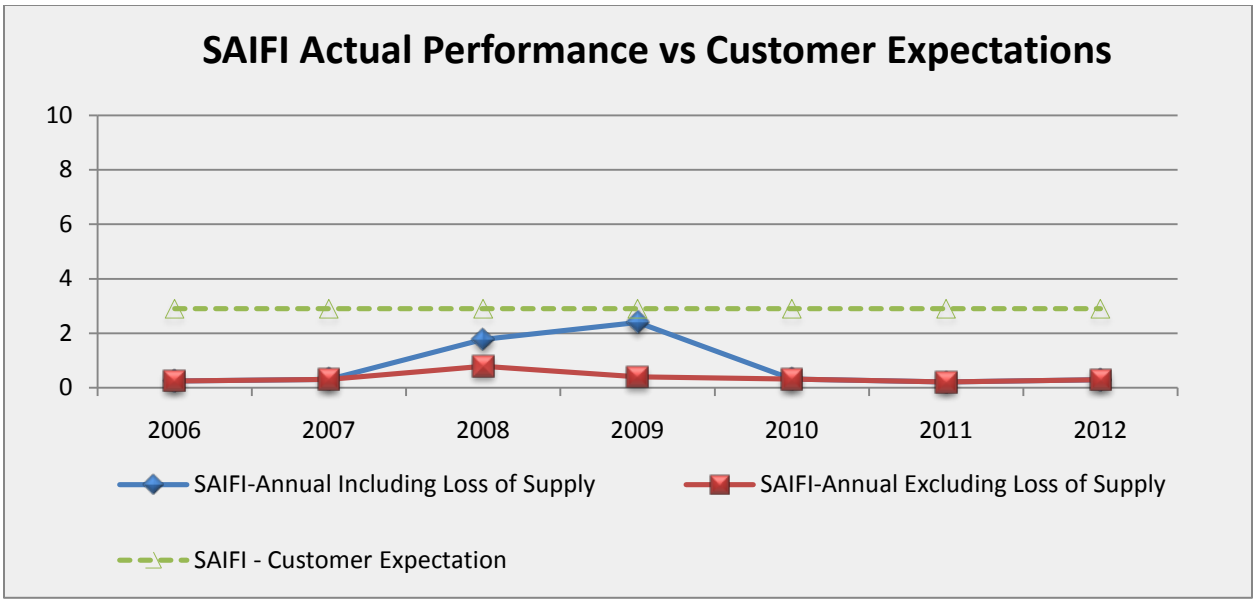




Notice that Loss of Supply significantly impacted years 2008 and 2009. Overall FFPC's electrical distribution system is performing very well.



FFPC exceeded annual customer SAIDI expectations with the exception of 2009. FFPC notes that there is a large margin between the portion of SAIDI that is within FFPC's control (excluding loss of supply) and customer expectations.



FFPC has good track record of exceeding annual customer SAIFI expectations. FFPC notes that there is a large margin between the portion of SAIFI that is within FFPC's control (excluding loss of supply) and customer expectations.

5.2.3.6.b.i.5 Performance Trend & Assessment

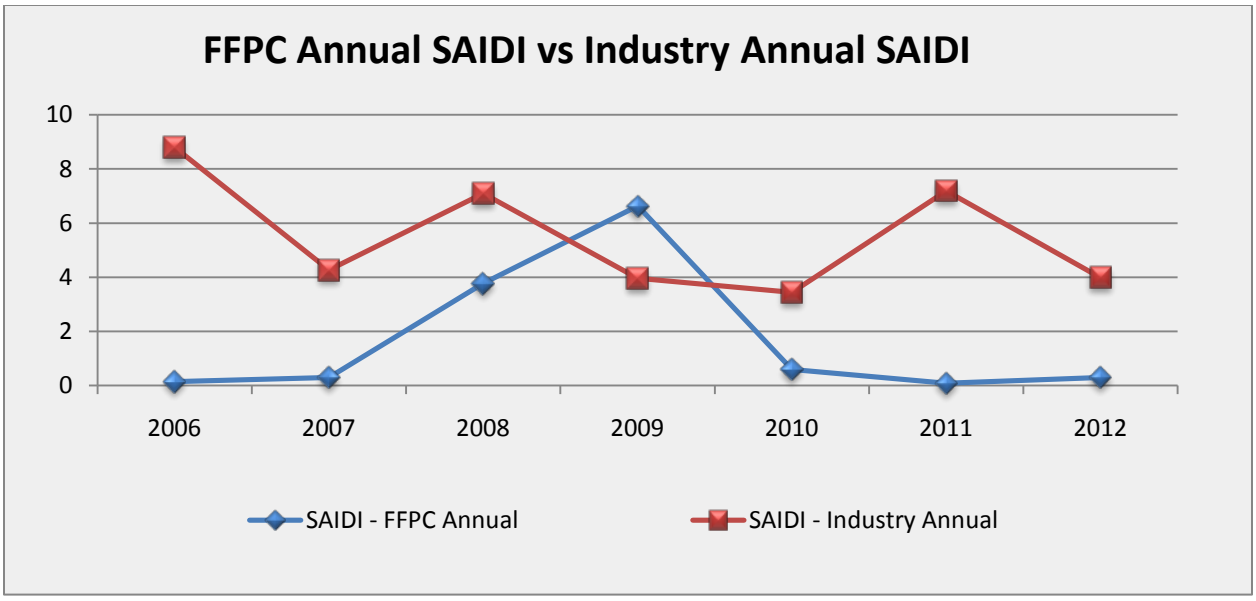
FFPC is pleased with the performance of its electrical distribution system. FFPC's largest opportunity for improving system reliability performance measures lies in the loss of supply category. Although loss of supply incidents generally do not occur frequently, when they do, they dominate annual distribution system performance degradation. FFPC will investigate the potential of improving the reliability of its transmission supply from HONI.

The portion of system reliability performance that is within FFPC's direct control is not identified as needing improvement or to be a driver requiring material investments over the planning period. FFPC's objective is to maintain current performance levels which greatly exceed customer expectations. FFPC acknowledges sustained reliability improvements in 2010, 2011 and 2012 relative to the lowest performance in 2009.

FFPC Customer Reliability & Performance versus Industry:

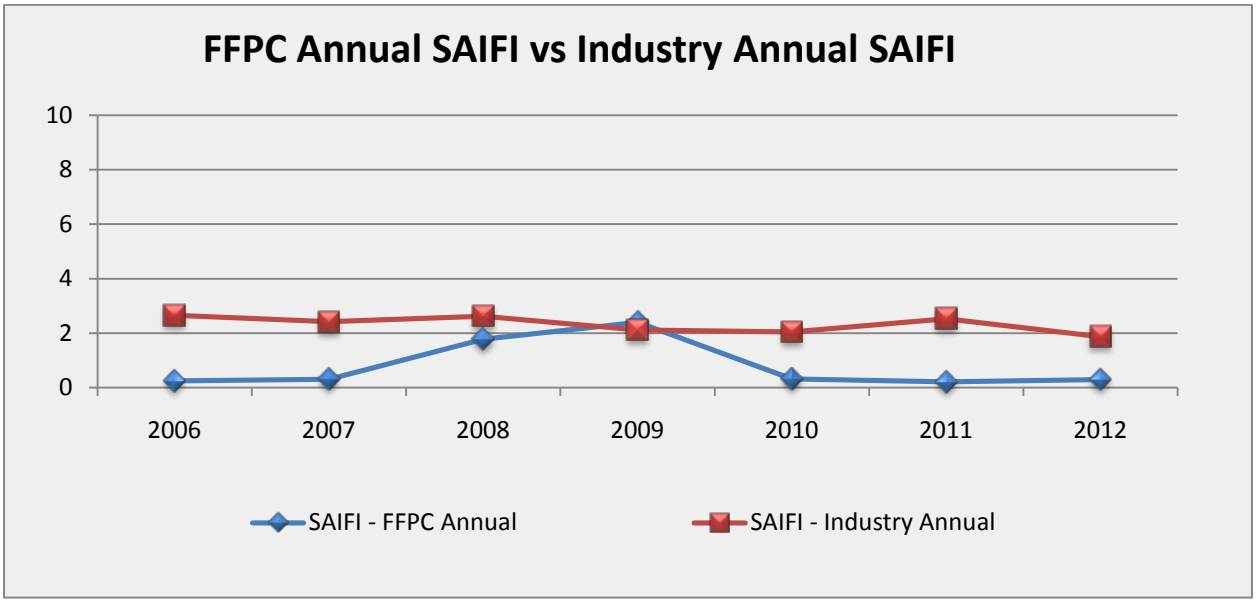
The following is comparison of the reliability that FFPC's customers experience versus the industry average in Ontario, as per the data available from OEB Yearbooks. Please note that the performance measures include loss of supply, to reflect the true reliability that customers experience.

FFPC Annual SAIDI vs Industry Annual SAIDI							
	2006	2007	2008	2009	2010	2011	2012
SAIDI - FFPC Annual	0.15	0.30	3.77	6.63	0.60	0.09	0.30
SAIDI - Industry Annual	8.80	4.27	7.10	3.96	3.44	7.19	3.99



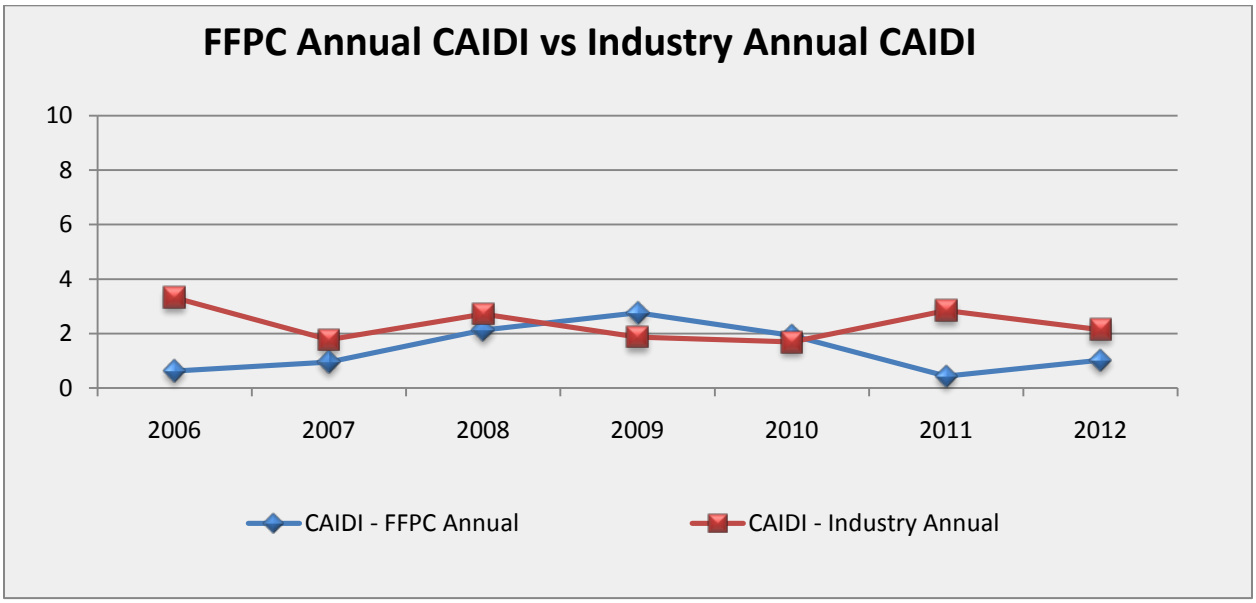
FFPC's annual interruption durations were shorter than those of industry six out of seven years.

FFPC Annual SAIFI vs Industry Annual SAIFI							
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
SAIFI - FFPC Annual	0.24	0.31	1.77	2.40	0.31	0.21	0.30
SAIFI - Industry Annual	2.66	2.42	2.62	2.11	2.04	2.53	1.86



FFPC's annual interruption frequency was lower than those of industry six out of seven years.

FFPC Annual CAIFI vs Industry Annual CAIFI							
	2006	2007	2008	2009	2010	2011	2012
CAIDI - FFPC Annual	0.62	0.95	2.13	2.76	1.92	0.43	1.02
CAIDI - Industry Annual	3.31	1.77	2.71	1.87	1.69	2.84	2.14



Note that FFPC's annual interruption duration was shorter than those of industry five out of seven years.

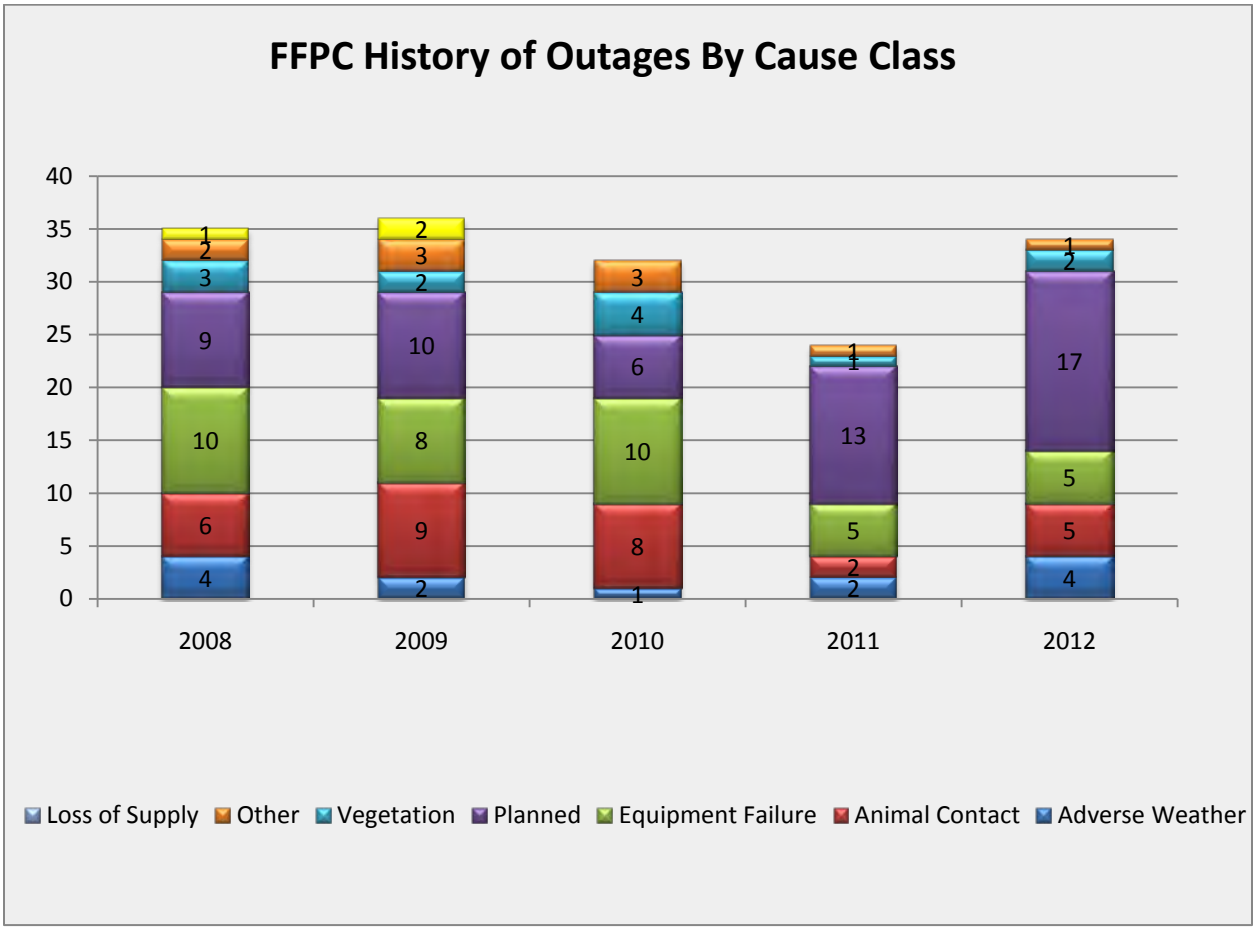
5.2.3.6.b.ii. Annual Outage Root Cause Failure Analysis

In 2008, FFPC started to formally track all root causes of outages. FFPC groups outages into the following categories; Adverse Weather; Animal Contact; Equipment Failure; Loss of Supply; Planned; Vegetation; and Other.

Most adverse weather related outages are caused by high winds and lightning strikes. Animal contacts are mainly caused by squirrels and raccoons. The following table summarizes the annual number of outage incidents by category:

FFPC Outage Cause History						
Cause Class	2008	2009	2010	2011	2012	Total
Adverse Weather	4	2	1	2	4	13
Animal Contact	6	9	8	2	5	30
Equipment Failure	10	8	10	5	5	38
Planned	9	10	6	13	17	55
Vegetation	3	2	4	1	2	12
Other	2	3	3	1	1	10
Loss of Supply	1	2	0	0	0	3
Total	**35**	**36**	**32**	**24**	**34**	**161**

The following is a graphical representation of annual causes of outages:



The following table summarizes the classes of outage causes in the order of most frequent class to least frequent class.

FFPC Most Frequent Outage Causes - Ranked By Highest to Lowest Cause Class							
Cause Class	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**	**% Cause**
Planned	9	10	6	13	17	55	34.2%
Equipment Failure	10	8	10	5	5	38	23.6%
Animal Contact	6	9	8	2	5	30	18.6%
Adverse Weather	4	2	1	2	4	13	8.1%
Vegetation	3	2	4	1	2	12	7.5%
Other	2	3	3	1	1	10	6.2%
Loss of Supply	1	2	0	0	0	3	1.9%
Total	**35**	**36**	**32**	**24**	**34**	**161**	**100%**

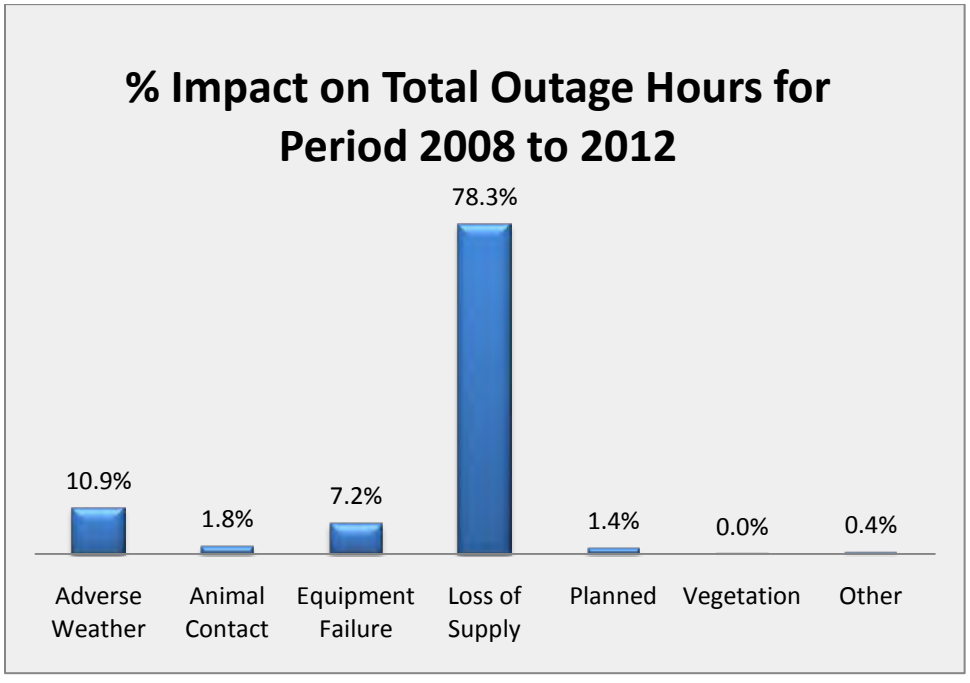
5.2.3.6.b.ii.1 Outage Class Interruption Frequency

It is important to note that FFPC's most frequent causes of outages are:

1. Planned Outages
2. Equipment Failure
3. Animal Contact
4. Adverse Weather

The most important aspect of evaluating outage causes is to evaluate the impact of each cause class. Although several causes occur more frequently, they have a relatively small impact on overall system performance. Planned Outages and Animal Contacts occur relatively frequently; however, they have a minimal impact on overall performance. The following table and graph represent the percentage of overall impact that each outage class has had on the Total Customer Hours of outages (number of customers affected x time), for the period 2008 to 2012.

Impact of Outage Class on Total Customer Hours for the Period 2008 to 2012	
Cause Class	% Impact
Loss of Supply	78.3%
Adverse Weather	10.9%
Equipment Failure	7.2%
Animal Contact	1.8%
Planned	1.4%
Vegetation	0.0%
Other	0.4%
Total	100.0%



It is important to note that only 3 out of a total of 106 unplanned outage incidents during the period 2008 to 2012 were due to a loss of supply; however, they account for 78.3% of total customer-hours of unplanned outages. This again highlights the significant impact that loss of supply has on the reliability of electricity that FFPC's customers experience.

Only 22.5% of all customer interruption hours are attributed to events on FFPC's electrical distribution system. Of the 22.5%, the largest contributors were Adverse Weather, Equipment Failure and Animal Contacts.

5.2.3.6.b.ii.2 Planned Outages

It is also important to note that although planned outages are the most frequent cause of outages, the overall impact of them is relatively small, representing 1.4% of total customer interruption hours. This is largely due to the fact that planned outages typically only affect a handful of customers. Planned outages are usually required to accommodate planned capital projects, such as transformer replacements or transferring of services from old poles to new poles. They are necessary to maintain the safety of employees and the general public.

5.2.3.6.b.ii.3 Adverse Weather

Distributors are somewhat at the mercy of Mother Nature, as bad weather cannot be controlled. FFPC has taken measures to minimize outages related to adverse weather conditions. Most notable measures are maintaining a structurally sound fleet of wood poles, an aggressive tree trimming program, as well as periodic conductor tensioning initiatives. Almost half of weather related outages are due to lighting strikes. Any lightning strike has a high probability of damaging or weakening distribution system components, even if an immediate outage does not occur. Usually lighting strikes result in the activation of current limiting protective devices such as fuses or lightning arrestors. It should be noted that transformer failures from lightning strikes are tracked under this category as opposed under equipment failure.

In summation, 6 out of 13 adverse weather incidents were as a result of lightning strikes, another 6 were due to high winds and 1 was due to excessive snow loading. FFPC's strategy to mitigate the impacts of adverse weather is:

- To conduct an aggressive tree trimming program to minimize contact of conductors with vegetation, as well as airborne debris during periods of high winds.
- To maintain a thorough maintenance inspection program that identifies deficiencies and likely causes of future unplanned outages or unsafe conditions (continually finding the weakest links).
- To maintain the overall structural integrity of wood pole lines, by keeping pace with the rate of deterioration of components (capital sustainment or development projects as per the outputs of the asset management process).
- To conduct periodic conductor tensioning initiatives, according to inspection findings.

5.2.3.6.b.ii.4 Equipment Failure

FFPC has been utilizing equipment failure summaries to assess patterns of failure. The failure analysis results are important inputs into the asset management process, as they have the potential of being

drivers for significant investment. The analysis results potentially affect maintenance planning, inspection planning, as well as capital replacement or sustainment planning. For the period 2008 to 2012, the most common equipment failures by category were Transformers, Switches and Conductors. The following table summarizes the failures. It is important to note that several transformers failed due to lightning strikes and that those failures were captured under the "Adverse Weather" category. Transformer failures in the "Equipment Failure" category failed due to other factors, such as overloading.

Transformers		Conductors & Terminations		Switches		Smart Meters		Misc Hardware	
Transformer	**7**	Conductor	2	Fuse Link	1	Smart Meter	4	Insulator	1
Lightning Arrester	6	Splice	2	**Switch**	**7**				
		Connection	2	Cutout	1				
		Termination	1	Switchgear Bushing	1				
		Insulink	2						
		Line Clamp	1						
Total	13	Total	10	Total	10	Total	4	Total	1

5.2.3.6.b.ii.5 Animal Contact

Unplanned outages caused by animal contacts have decreased significantly over the last decade. FFPC has standardized on equipping its overhead transformers with squirrel guards. The guards prevent animals from climbing from the lid of transformers onto the primary conductor, which if both are contacted at the same time, results in a short circuit and a subsequent blown transformer fuse. FFPC will continue to utilize its inspection process to ensure that the animal guards remain in good working condition.

5.2.3.6.b.ii.6 Key Inputs into Asset Management Process

FFPC's top three contributing causes, to overall customer outage hours over the period 2008 to 2012 are: Loss of Supply, Adverse Weather and Equipment Failure. Each category contributed the following percentages:

Loss of Supply	78.3%
Adverse Weather	10.9%
Equipment Failure	7.2%
Total	96.4%

FFPC plans to consult with HONI to investigate supply point reliability improvement opportunities. FFPC plans to continue with its detailed maintenance inspection program, to proactively identify deficiencies that have a high risk of failure or present undue hazards. FFPC plans to closely monitor the health of its transformers, switches, and the quality of conductors and connections.

Transformer and switch failures are the highest contributors to equipment failures which result in unplanned outages. FFPC's asset management process has identified that approximately 18% of the entire transformer population will reach the end of their suggested forty (40) year useful service life by 2018. The aging transformer fleet aligns with the results of the outage cause analysis, which identified transformer failures as being the most frequent equipment failure resulting in customer interruptions. As such, transformer replacements have a very large impact on FFPC's 2014 - 2018 DS Plan.

5.2.3.6.c. Overall Cost Performance

As discussed under section 5.2.1.5 "Unique Embedded OM&A Costs", FFPC has significant expenses imbedded into its OM&A costs, that are directly associated with the upkeep and operation of its High Voltage (Greater than 50 kV) Transformer Station, as well as the 1905 Historic Power Agreement. As such, all RRR reported OM&A costs sustain three distinct business aspects; however, historically they have always been lumped together and treated as distribution expenses. As previously mentioned, prior to the year end of 2012, FFPC's transformer station was improperly classified as a "less than 50 kV station" when it is actually a "greater than 50 kV station" (High Voltage Asset). As such, all associated expenses have historically always been reported and treated as distribution expenses. Given the increased focus on distributor performance and the expectation to "bend the cost curve", it is important to note that FFPC's OM&A costs as reported cannot be directly compared to that of other distributors, as they are inclusive of all three business aspects (distribution, HV Station & Historic Power Agreement) and the comparison would not be "apples to apples". Furthermore, FFPC is concerned that its placement into efficiency cohort Group IV in the November 21, 2013 released PEG Report is inaccurate, as FFPC's unique circumstances were not understood and as such could not be taken into consideration. FFPC believes that it will be penalized with its assigned stretch factor of 0.45% if its unique circumstances are not taken into consideration. It is worth noting that the stretch factor of 0.45% to is assigned to distributors having actual costs between 10% to 25% higher than predicted.

With respect to Performance Outcomes, FFPC is able to offer its customers among the lowest rates in the Province, according to the OEB's online bill calculator (and the bill impact calculation in this COS); however, the November 21, 2013 released PEG report ranked FFPC as 58th with respect to "Difference Between Actual and Predicted Cost: Cost Benchmarking Model" (table 17).

FFPC respectfully requests that the Board be mindful of FFPC's unique circumstances when evaluating its "cost performance". FFPC would be pleased to work with the Board, as well as PEG staff to revise FFPC's cost structure (and historic data used) for benchmarking purposes, such that a fair and accurate stretch factor can be obtained.

5.2.3.6.c.i. OM&A Cost Comparisons

FFPC has tabulated its various OM&A Cost comparators as per Board Staff's July 2013 recommended scorecard. As FFPC's OM&A costs are inclusive of operating and up keeping the historic power agreement and HV station, FFPC has provided a rate of change analysis (% change by year). FFPC finds the rate of change analysis a good tool for assessing long term performance trends. The analysis is also a useful tool for assessing performance relative to industry. The source data for all OM&A cost comparisons was extracted from the OEB's annual distributor year books. The following table contains

the list of comparators, as well as base inputs that FFPC relied upon to assess its OM&A related performance:

Cost Performance Comparators	2005	2006	2007	2008	2009	2010	2011	2012	2005 to 2012 Average
FFPC OM&A Reported	1,064,846	1,125,164	1,146,014	1,250,883	1,316,559	1,325,684	1,301,992	1,620,129	1,268,909
Industry OM&A Reported	994,820,205	1,079,540,064	1,199,224,784	1,210,181,289	1,266,934,047	1,350,642,664	1,412,233,814	1,513,210,665	1,253,348,442
FFPC % OM&A Increase relative to 2005	0%	5.7%	7.6%	17.5%	23.6%	24.5%	22.3%	52.1%	21.9%
Industry % OM&A Increase relative to 2005	0%	8.5%	20.5%	21.6%	27.4%	35.8%	42.0%	52.1%	29.7%
FFPC # Customers	4,040	3,981	3,864	4,001	3,768	3,777	3,775	3,780	3,873
Industry # Customers	4,522,869	4,590,958	4,634,998	4,693,045	4,748,558	4,788,667	4,839,185	4,893,782	4,714,008
Adjusted FFPC # Customers - (Adjusted to Reflect Industry Equivalent Customer Growth)	4,040	4,101	4,140	4,192	4,242	4,277	4,323	4,371	4,211
FFPC % Change in # Customers Relative to 2005	0%	-1.5%	-4.4%	-1.0%	-6.7%	-6.5%	-6.6%	-6.4%	-4.7%
Industry % Change in # Customers Relative to 2005	0%	1.5%	2.5%	3.8%	5.0%	5.9%	7.0%	8.2%	4.8%
Adjusted FFPC % Change in # Customers Relative to 2005 - (Adjusted to Reflect Industry Equivalent Customer Growth)	0%	1.5%	2.5%	3.8%	5.0%	5.9%	7.0%	8.2%	4.8%
FFPC Circuit km of Line	84	84	84	84	84	84	74	74	82
Industry Circuit km of Line	203,896	200,887	196,242	195,779	196,815	197,588	194,707	195,858	197,722
Adjusted FFPC Circuit km of Line - (Adjusted to Reflect Improved Accuracy from GIS System)	74	74	74	74	74	74	74	74	74
Adjusted FFPC Circuit km of Line - (Adjusted to Reflect Industry Equivalent Decrease in Circuit Length)	74	72.9	71.2	71.1	71.4	71.7	70.7	71.1	71.8
FFPC % Change in Circuit km of Line Relative to 2005	0%	0.0%	0.0%	0.0%	0.0%	0.0%	-11.9%	-11.9%	-3.4%
Industry % Change in Circuit km of Line Relative to 2005	0%	-1.5%	-3.8%	-4.0%	-3.5%	-3.1%	-4.5%	-3.9%	-3.5%
Adjusted FFPC % Change in Circuit km of Line Relative to 2005 - (Adjusted to Reflect Improved Accuracy from GIS System)	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Adjusted FFPC % Change in Circuit km of Line Relative to 2005 - (Adjusted to Reflect Industry Equivalent Decrease in Circuit Length)	0%	-1.5%	-3.8%	-4.0%	-3.5%	-3.1%	-4.5%	-3.9%	-3.5%
FFPC kWh Delivered (excluding losses)	83,923,661	82,347,301	83,900,561	84,002,098	82,503,680	79,739,754	79,562,547	76,310,422	81,536,253
Industry kWh Delivered (excluding losses)	123,810,922,688	121,675,238,626	125,729,367,887	123,503,514,640	118,959,458,726	121,191,511,801	121,038,008,423	119,995,730,310	121,987,969,137
Adjusted FFPC kWh Delivered (excluding losses) - (Adjusted to Reflect Industry Equivalent Change in kWh Delivered)	83,923,661	82,476,015	85,224,055	83,715,288	80,635,158	82,148,127	82,044,076	81,337,581	82,687,995
FFPC % Change in kWh Delivered (excluding losses) Relative to 2005	0%	-1.9%	0.0%	0.1%	-1.7%	-5.0%	-5.2%	-9.1%	-3.3%

Industry % Change in kWh Delivered (excluding losses) Relative to 2005	0%	-1.7%	1.5%	-0.2%	-3.9%	-2.1%	-2.2%	-3.1%	-1.7%
FFPC Adjusted % Change in kWh Delivered (excluding losses) Relative to 2005 - (Adjusted to Reflect Industry Equivalent Change in kWh Delivered)	0%	-1.7%	1.5%	-0.2%	-3.9%	-2.1%	-2.2%	-3.1%	-1.7%
FFPC OM&A per Customer (RRR Reported)	263.58	282.63	296.59	312.64	349.41	350.99	344.90	428.61	328.67
Industry OM&A per Customer (RRR Reported)	219.95	235.14	258.73	257.87	266.80	282.05	291.83	309.21	265.20
Adjusted FFPC OM&A per Customer - (Adjusted to Reflect Industry Customer Growth)	263.58	274.38	276.80	298.40	310.39	309.93	301.21	370.63	300.66
FFPC % Increase in OM&A per Customer Relative to 2005 (RRR Reported)	0%	7.2%	12.5%	18.6%	32.6%	33.2%	30.9%	62.6%	28.2%
Industry % Increase in OM&A per Customer Relative to 2005 (RRR Reported)	0%	6.9%	17.6%	17.2%	21.3%	28.2%	32.7%	40.6%	23.5%
Adjusted FFPC % Increase in OM&A per Customer Relative to 2005 - (Adjusted to Reflect Industry Customer Growth)	0%	4.1%	5.0%	13.2%	17.8%	17.6%	14.3%	40.6%	16.1%
FFPC OM&A per kWh Delivered	0.01269	0.01366	0.01366	0.01489	0.01596	0.01663	0.01636	0.02123	0.01564
Industry OM&A per kWh Delivered	0.00803	0.00887	0.00954	0.00980	0.01065	0.01114	0.01167	0.01261	0.01029
Adjusted FFPC OM&A per kWh Delivered - (Adjusted to Reflect Industry Equivalent Change in kWh Delivered)	0.01269	0.01364	0.01345	0.01494	0.01633	0.01614	0.01587	0.01992	0.01537
FFPC % Increase in OM&A per kWh Delivered Relative to 2005	0%	7.7%	7.7%	17.4%	25.8%	31.0%	29.0%	67.3%	26.5%
Industry % Increase in OM&A per kWh Delivered Relative to 2005	0%	10.4%	18.7%	22.0%	32.5%	38.7%	45.2%	56.9%	32.1%
Adjusted FFPC % Increase in Reported OM&A per kWh Delivered Relative to 2005 - (Adjusted to Reflect Industry Equivalent Change in kWh Delivered)	0%	7.5%	6.0%	17.8%	28.7%	27.2%	25.1%	57.0%	24.2%
FFPC OM&A per km Circuit of Line	12676.7	13394.8	13643.0	14891.5	15673.3	15782.0	17594.5	21893.6	15693.7
Industry OM&A per km Circuit of Line	4879.1	5373.9	6110.9	6181.4	6437.2	6835.7	7253.1	7726.1	6349.7
Adjusted FFPC OM&A per km Circuit of Line - (Adjusted to Reflect Improved Accuracy from GIS System)	14389.8	15204.9	15486.7	16903.8	17791.3	17914.7	17594.5	21893.6	17147.4
FFPC % OM&A Increase per km Circuit of Line Relative to 2005	0%	5.7%	7.6%	17.5%	23.6%	24.5%	38.8%	72.7%	27.2%
Industry % OM&A Increase per km Circuit of Line Relative to 2005	0%	10.1%	25.2%	26.7%	31.9%	40.1%	48.7%	58.4%	34.4%
FFPC Adjusted % OM&A Increase per km Circuit of Line Relative to 2005 - (Adjusted to Reflect Improved Accuracy from GIS System)	0%	5.7%	7.6%	17.5%	23.6%	24.5%	22.3%	52.1%	21.9%

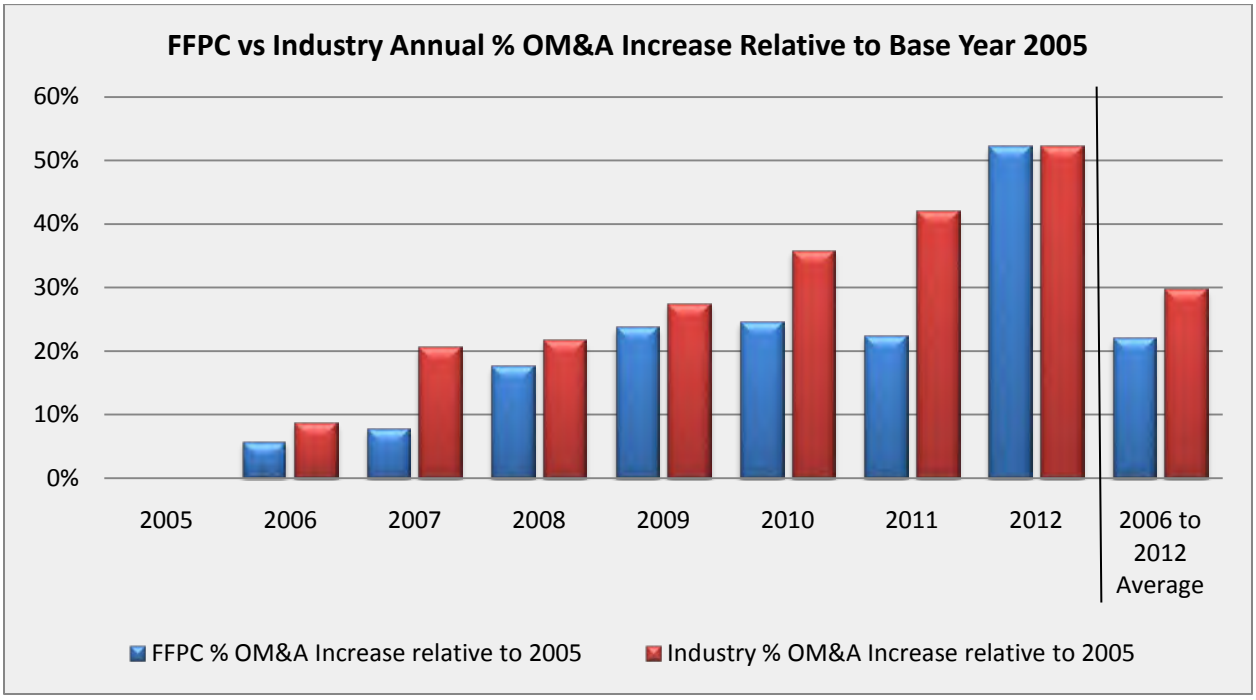
Notes: Rate of change % averages are relative to 2005 and are therefore 2006 to 2012 averages.
Blue font denotes adjusted measure for comparative purposes.

5.2.3.6.c.i.1 OM&A (RRR Reported)

Refer to section 5.2.3.6.c.i for the summary of FFPC's RRR reported OM&A expenses, as well as those reported by industry (based on OEB Yearbooks).

5.2.3.6.c.i.1.a OM&A Performance History

The following graph illustrates FFPC's and Industry's performance history with respect to annual % Increase in OM&A Expenditures for the period 2006 to 2012, relative to the base year 2005.



5.2.3.6.c.i.1.b OM&A Performance Trend and Assessment

Over the period 2006 through 2012 FFPC's average annual increase in OM&A expense was 21.9%, and the average annual increase reported by industry was 29.7%. As such, FFPC estimates that it was able to avoid $581k in OM&A expense, relative to the requirements of industry. The savings are largely attributed to FFPC's approach of adjusting its business needs on a reactive basis, upon the numerous major industry changes that occurred between 2005 and 2012 reaching their steady state. FFPC credits its staff and service providers for enduring significantly intensified short term workloads, which were necessary to successfully implement the numerous sector changes. The current level of effort exerted by FFPC's staff is not sustainable, and as such FFPC is realigning its revenue requirement in this COS to fund additional resources (the addition of a Technical Customer Service Representative to staff, as well as more necessary services from third party service providers including Human Resources, Legal, IT, and Skills Development expertise).

Over the period 2005 to 2012, the most notable OM&A expense increase occurred in 2012. The jump in expense occurred due largely to the recognition of approximately $392k in smart meter related expenses from to the clearance of relevant variance accounts (1555 & 1556). Overall, FFPC is pleased

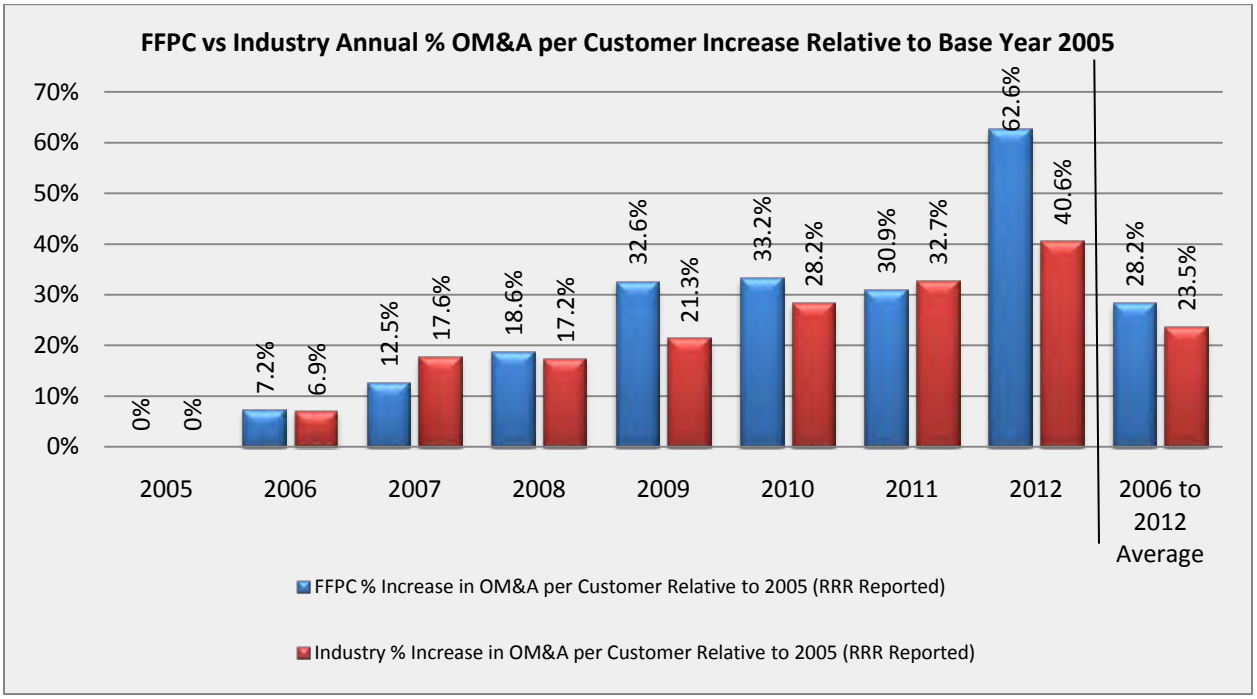
with its OM&A performance trend and believes that it demonstrates wise spending in the best interest of consumers, for whom FFPC exists.

5.2.3.6.c.i.2 OM&A per Customer

FFPC performed its OM&A per Customer analysis based on data contained in the OEB's published Annual Yearbooks.

5.2.3.6.c.i.2.a OM&A per Customer Performance History

The following graph illustrates FFPC's and Industry's performance history with respect to annual % Increase in OM&A Expenditures per Customer for the period 2006 to 2012, relative to the base year 2005.



5.2.3.6.c.i.2.b OM&A per Customer Performance Trend and Assessment

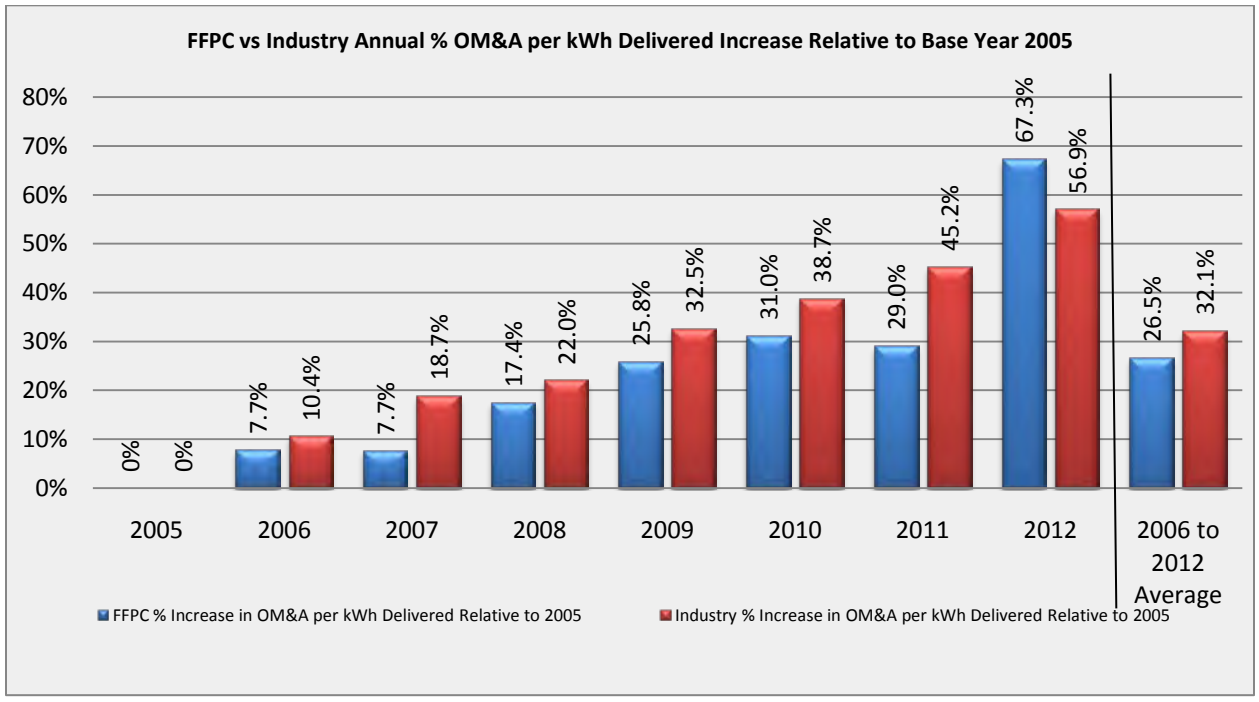
FFPC's annual percent change in OM&A expense per customer increased at a rate slightly higher than that of industry. FFPC's average % OM&A increase over the period 2006 to 2012 was 28.2%, compared to 23.5% for industry. FFPC's higher increase rate was largely influenced by the decline in FFPC's customer base from 4,040 in 2005 to 3,780 in 2012 (-6.4%). If FFPC's customer base grew at a pace equivalent to that of industry, FFPC would have been able to spread out fixed OM&A costs across 4,371 customers by 2012. As such, FFPC notes that its actual underperformance relative to that of industry was largely influenced by its 6.4% loss in customer base which is a variable that FFPC cannot control.

5.2.3.6.c.i.3 OM&A per kWh Delivered

FFPC performed its OM&A per kWh Delivered analysis based on data contained in the OEB's published Annual Yearbooks.

5.2.3.6.c.i.3.a OM&A per kWh Delivered Performance Trend

The following graph illustrates FFPC's and Industry's performance history with respect to annual % Increase in OM&A Expenditures per kWh Delivered for the period 2006 to 2012, relative to the base year 2005.



5.2.3.6.c.i.3.b OM&A per kWh Delivered Performance Trend and Assessment

FFPC's annual percent change in OM&A expense per kWh Delivered increased at a rate slightly lower than that of industry. FFPC's average percent OM&A increase over the period 2006 to 2012 was 26.5%, compared to 32.1% for industry. FFPC's increase rate was influenced by the decline in FFPC's volume of sales, which declined at an average annual rate of -3.3% versus -1.7% for industry. If FFPC's annual percent change in volume of sales was equivalent to that of industry, FFPC would have been able to spread out its fixed OM&A costs across a larger volume. FFPC notes that although its volume of sales decreased at twice the rate experienced by industry, FFPC's actual performance was still slightly better than that of industry.

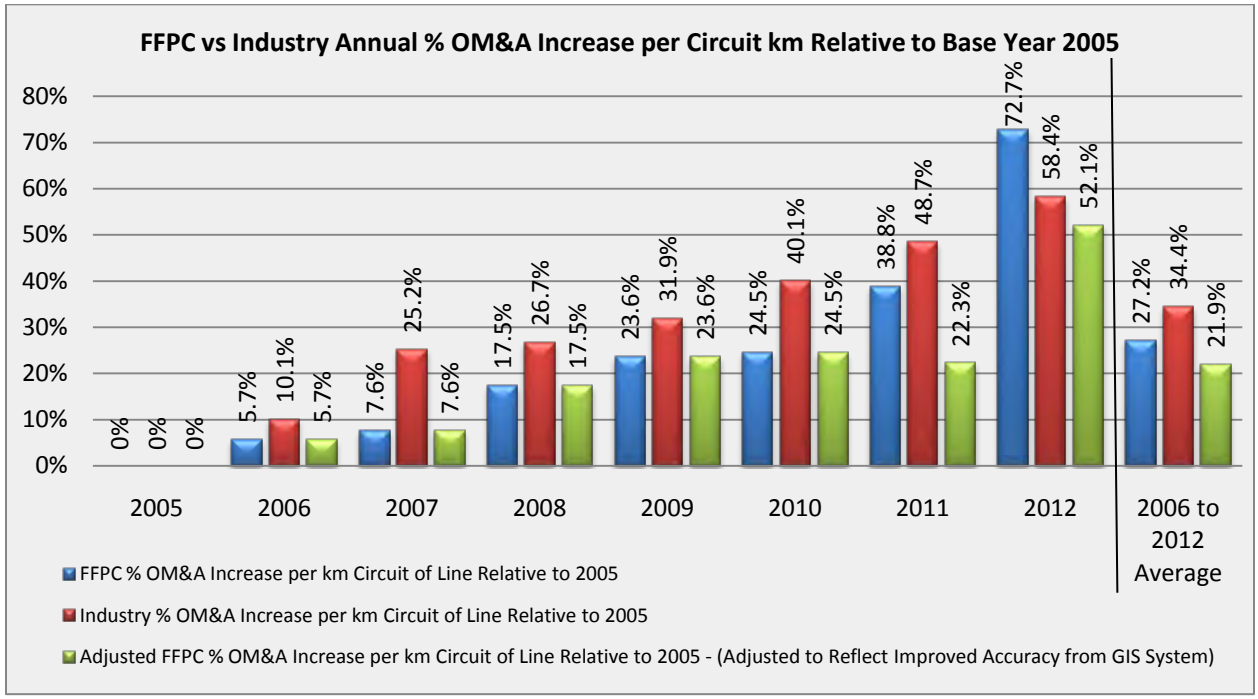
5.2.3.6.c.i.4 OM&A per Circuit km of Line

FFPC performed its OM&A per Circuit km of Line analysis based on data contained in the OEB's published Annual Yearbooks. FFPC notes that its reported Circuit km decreased from 84 km to 74 km in

2011, due to the availability of more accurate dimensional data obtained from its GIS system, and as such no physical plant was removed.

5.2.3.6.c.i.4.a OM&A per Circuit km of Line Performance History

The following graph illustrates FFPC's and Industry's performance history with respect to annual % Increase in OM&A Expenditures per Circuit km of Line for the period 2006 to 2012, relative to the base year 2005. The "Adjusted FFPC % OM&A Increase per km Circuit of Line" variable corrects FFPC's reported Circuit km of Line for years 2005 to 2010 due to the availability of more accurate dimensional data from the GIS system. FFPC's actual circuit km is 74 km (incorrectly reported as 84 prior to 2011 as GIS dimensional data was not available at that time)



5.2.3.6.c.i.4.b OM&A per Circuit km of Line Performance Trend and Assessment

FFPC's annual percent increase in OM&A expense per Circuit km of Line increased at a rate slightly lower than that of industry. FFPC's average percent OM&A increase over the period 2006 to 2012 was 27.2%, compared to 34.4% for industry. FFPC's reported increase rate was materially influenced by the reduction in reported Circuit km in 2011 forward. As such, the "Adjusted FFPC % OM&A Increase per km Circuit of Line" variable is a more accurate reflection of FFPC's true performance for this measure, as the physical circuit km of its plant did not change. FFPC's average Adjusted % OM&A Increase per Circuit km of Line was 21.9% with the improved GIS dimensional data, relative to 34.4% for industry. FFPC notes that its performance was slightly better than that of industry.

5.2.3.6.d. Total Bill Impact - Residential Customers

According to FFPC's Customer Satisfaction Survey that was conducted over the summer of 2013, the top two issues identified by customers in regards to their concerns with the electrical industry were the Overall Cost of Electricity, and fear of losing the 1905 Historic Power Agreement. As such, it was important for FFPC to assess its overall cost performance relative to industry, by conducting a Total Bill Comparison for residential consumers. FFPC believes that Total Bill comparisons are an important aspect of Performance Outcomes. The following Total Bill Impact comparison is based on the data made available by the Boards' online bill calculator. It is important to note that FFPC excluded Seasonal, First Nations distributors, Remote Communities, as well as R1 Low Density rates from the comparison (although FFPC's customer density would be an R1 Density, as it is below the threshold of 60 customers per line km).

The following list of distributors and corresponding rate zones are included in the comparison that was conducted relative to November 25, 2013 data. Please note that FFPC removed all distributor names from performance rankings, as the emphasis in on FFPC's performance and not on that of other LDC's:

Algoma Power Inc.
Atikokan Hydro Inc.
Bluewater Power Distribution Corporation
Brant County Power Inc.
Brantford Power Inc.
Burlington Hydro Inc.
Cambridge and North Dumfries Hydro Inc.
Canadian Niagara Power Inc. - Eastern Ontario Power
Canadian Niagara Power Inc. - Fort Erie
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.
Centre Wellington Hydro Ltd.
Chapleau Public Utilities Corporation
COLLUS PowerStream Corp.
Cooperative Hydro Embrun Inc.
E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.
Entegrus Powerlines Inc.
EnWin Utilities Ltd.
Erie Thames Powerlines Corporation
Espanola Regional Hydro Distribution Corporation
Essex Powerlines Corporation
Festival Hydro Inc. - Hensall
Festival Hydro Inc. - Main
Fort Frances Power Corporation
Fort Frances Power Corporation - Including 1905 Historic Power Agreement Benefit
Greater Sudbury Hydro Inc.
Grimsby Power Incorporated

Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.
Hearst Power Distribution Company Limited
Horizon Utilities Corporation
Hydro 2000 Inc.
Hydro Hawkesbury Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc. - Medium Density (R1)
Hydro One Networks Inc. - Urban (UR)
Hydro Ottawa Limited
Innisfil Hydro Distribution Systems Limited
Kenora Hydro Electric Corporation Ltd.
Kingston Hydro Corporation
Kitchener-Wilmot Hydro Inc.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
London Hydro Inc.
Midland Power Utility Corporation
Milton Hydro Distribution Inc.
Newmarket-Tay Power Distribution Ltd. - Newmarket
Newmarket-Tay Power Distribution Ltd. - Tay
Niagara Peninsula Energy Inc. - Niagara Falls
Niagara Peninsula Energy Inc. - Peninsula West
Niagara-on-the-Lake Hydro Inc.
Norfolk Power Distribution Inc.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Oakville Hydro Electricity Distribution Inc.
Orangeville Hydro Limited
Orillia Power Distribution Corporation
Oshawa PUC Networks Inc.
Ottawa River Power Corporation
Parry Sound Power Corporation
Peterborough Distribution Incorporated
PowerStream Inc. - Barrie
PowerStream Inc. - South
PUC Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.
Sioux Lookout Hydro Inc.
St. Thomas Energy Inc.

Thunder Bay Hydro Electricity Distribution Inc.
Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc. - Gravenhurst
Veridian Connections Inc. - Main
Wasaga Distribution Inc.
Waterloo North Hydro Inc.
Welland Hydro-Electric System Corp.
Wellington North Power Inc.
West Coast Huron Energy Inc.
Westario Power Inc.
Whitby Hydro Electric Corporation
Woodstock Hydro Services Inc.

5.2.3.6.d.i.1 Total Bill Impact Comparison - Residential Customers

The following chart illustrates FFPC's current performance rank with respect to Total Customer Bill for 800 kWh of electricity consumed. The comparisons are based on the default settings in the Board's calculator and are therefore relative to: Residential Customers; Total monthly consumption of 800 kWh; and current Time-of-Use Pricing with the usage split being 64% off-peak, 18% on-peak and 18% mid-peak. Please note that FFPC encountered a minor discrepancy between the online bill calculator's Total Bill calculation for FFPC, compared to the Total Bill generated by the 2014 COS Bill Impacts working sheets (COS Appendix 2-W - Bill Impact), which are based on FFPC's current Board approved rates. FFPC believes the 2014 COS model to be accurate and as such used the total cost generated by it for the following comparisons:

Distributor Total Bill Calculation as Per OEB Online Bill Calculator on November 25, 2013	
Rank	**Total Bill Including OCEB**
1 - Fort Frances Power Corporation - Including 1905 Historic Power Agreement Credit as at November 25, 2013	$84.95
2 - Fort Frances Power Corporation (Board approved as at November 25, 2013)	$106.49
3	$108.35
4	$111.02
5	$111.25
6	$111.48
7	$114.62
8	$115.33
9	$115.36
10	$116.02

11	$116.83
12	$117.16
13	$118.62
14	$118.72
15	$118.74
16	$119.15
17	$119.79
18	$120.09
19	$120.44
20	$120.58
21	$120.93
22	$121.01
23	$121.31
24	$121.59
25	$121.68
26	$121.74
27	$121.98
28	$122.01
29	$122.22
30	$122.41
31	$122.44
32	$122.81
33	$123.38
34	$123.43
35	$123.44
36	$123.45
37	$123.86
38	$123.98
39	$124.10
40	$124.54
41	$124.71
42	$124.90
43	$125.13
44	$125.27
45	$125.38
46	$125.44
47	$125.54
48	$125.68
49	$125.72
50	$126.09
51	$126.55
52	$127.08

53	$127.29
54	$127.42
55	$127.55
56	$127.73
57	$128.02
58	$128.72
59	$128.85
60	$129.12
61	$129.37
62	$129.59
63	$130.69
64	$131.78
65	$132.67
66	$134.32
67	$134.57
68	$134.57
69	$135.08
70	$135.27
71	$137.03
72	$137.08
73	$137.26
74	$137.49
75	$137.50
76	$138.35
77	$139.20
78	$139.22
79	$139.54
80	$141.48
81	$149.83
82	$152.61

The following table illustrates FFPC's 2014 COS proposed rates and the corresponding Total Estimated Bill for 800 kWh of TOU consumption. The table compares FFPC's proposed 2014 residential bill relative to 2013 residential bills for industry as per the OEB's online calculator.

FFPC 2014 COS Proposed Rates versus 2013 Industry Rates as per OEB Bill Calculator on November 25, 2013	
Utility / Rate Zone	Total Bill Including OCEB
1 - Fort Frances Power Corporation - 2014 COS Proposed Including 1905 Historic Power Agreement Benefit	$89.78
2	$108.35
3	$111.02
4	$111.25
5	$111.48
6 - Fort Frances Power Corporation 2014 COS Proposed (excluding 1905 Power Agreement Credit)	$111.79
7	$114.62
8	$115.33
9	$115.36
10	$116.02
11	$116.83
12	$117.16
13	$118.62
14	$118.72
15	$118.74
16	$119.15
17	$119.79
18	$120.09
19	$120.44
20	$120.58
21	$120.93
22	$121.01
23	$121.31
24	$121.59
25	$121.68
26	$121.74
27	$121.98
28	$122.01
29	$122.22
30	$122.41

31	$122.44
32	$122.81
33	$123.38
34	$123.43
35	$123.44
36	$123.45
37	$123.86
38	$123.98
39	$124.10
40	$124.54
41	$124.71
42	$124.90
43	$125.13
44	$125.27
45	$125.38
46	$125.44
47	$125.54
48	$125.68
49	$125.72
50	$126.09
51	$126.55
52	$127.08
53	$127.29
54	$127.42
55	$127.55
56	$127.73
57	$128.02
58	$128.72
59	$128.85
60	$129.12
61	$129.37
62	$129.59
63	$130.69
64	$131.78
65	$132.67
66	$134.32
67	$134.57
68	$134.57
69	$135.08
70	$135.27
71	$137.03
72	$137.08

73	$137.26
74	$137.49
75	$137.50
76	$138.35
77	$139.20
78	$139.22
79	$139.54
80	$141.48
81	$149.83
82	$152.61

5.2.3.6.d.i.2 Total Bill Impact for Residential Customers Performance Assessment

FFPC is pleased to be able to offer its customers the lowest rates in all of Ontario. For 2013, FFPC's residential rate without the inclusion of the 1905 Historic Power Agreement is ranked as 2nd, and it is ranked 1st with the inclusion of the agreement credit. FFPC is proposing to increase its residential rates by 4.97% in its COS application such that the total bill for 800 kWh of TOU consumption increases from $106.49 to $111.79 in 2014 without the historic power agreement credit. Under this scenario, FFPC's 2014 proposed distribution rates rank FFPC 6th lowest without inclusion of the power agreement, and 1st with the inclusion of it, relative to industry's current rates. FFPC expects its actual rank (excluding the historic credit) to improve from 6th in 2014, as industry adjusts its rates throughout 2014. As previously mentioned, FFPC incurs considerable unique OM&A costs associated with administering and protecting the 1905 Historic Power Agreement; however, they are prudently incurred in the best interest of consumers, as rates are thereby reduced significantly.

5.2.3.7 Public Policy Responsiveness Measures

FFPC has divided Public Policy Responsiveness Measures into two categories; Conservation and Demand Management; and Connection of Renewable Generation.

5.2.3.7.a. Conservation and Demand Management

On March 31, 2010, the Minister issued a Minister's Directive to the Ontario Energy Board, pursuant to sections 27.1 and 27.2 of the Ontario Energy Board Act. The Directive directed the Board to amend the licenses of all licensed electricity distributors by adding a condition that specifies each distributor must meet CDM Targets through the delivery of CDM Programs.

In response to the Minister's Directive, the Board Ordered that each licensed electricity distributor must deliver a mix of CDM Programs to all consumer types in the distributor's service area, whether through the Board-Approved CDM Programs, OPA-Contracted Province-Wide CDM Programs or a combination of

the two, as far as is appropriate and reasonable having regard to the composition of the distributor's consumer base.

FFPC's licence was amended such that, as a condition of its licence, FFPC must meet its CDM Targets of 2014 Net Annual Peak Demand Savings of 0.61 MW and 2011 - 2014 Net Cumulative Energy Savings of 3.64 GWh.

5.2.3.7.a.i. Performance History

The following tables illustrate FFPC's performance with respect to meeting the mandated 2014 Demand Savings and Energy Savings targets:

FFPC Net Annual Peak Savings Performance versus Provincial Performance						
	Directive		2011 Progress	2012 Progress	2013 Progress	2014 Progress
Distributor	Target	Units	% Target Achieved	% Target Achieved	% Target Achieved	% Target Achieved
FFPC	0.61	MW	2.30%	21.00%	N/A	N/A
Province	1,330	MW	9.69%	17.80%	N/A	N/A

5.2.3.7.a.ii. FFPC Net Annual Peak Saving Performance versus Province

FFPC Net Annual Demand Savings Performance versus Provincial Performance						
Distributor	Directive		2011 Progress	2012 Progress	2013 Progress	2014 Progress
	Target	Units	% Target Achieved	% Target Achieved	% Target Achieved	% Target Achieved
FFPC	3.64	GWh	11.75%	49.40%	N/A	N/A
Province	6,000	GWh	39.79%	65.10%	N/A	N/A

5.2.3.7.a.iii. Performance Trend & Assessment

FFPC was not able to officially launch its CDM efforts until the fall of 2011, due to the delay in the availability essentially all conservation program offerings. As such, FFPC achieved only a small portion of its mandated targets that year. Since the delayed launch, FFPC has experienced good uptake on many program offerings. FFPC has managed to surpass provincial results with respect to the peak reduction category and has greatly closed the gap with respect to volumetric reduction. FFPC anticipates improved results for the 2013 program year. The most notable 2013 CDM achievement is the community-wide conversion of conventional street lights to LED street lights. Approximately 80% of all fixtures have been replaced with LED style fixtures at the time of preparing the DS Plan. FFPC expects to meet its mandated CDM targets by the end of 2014. As a point of interest, the following picture illustrates the difference in lighting quality of Front Street being lit with newly installed LED fixtures, compared to traditional lighting along the side of the street, along the scenic waterfront, which is the international boundary between Canada and USA. Notice the bright white street compared to the yellow scenic walkway. Notice the bright white street compared to the yellow scenic walkway.



Figure 1 - Front Street LED Street Lighting Retrofit

5.2.3.7.b. Connection of Renewable Generation

The Feed-in-Tariff program has had relatively good customer uptake throughout FFPC's service territory. FFPC processed and connected its first microFIT project in 2010. As at July 2013, FFPC has 61 kW of microFIT generation and 100 kW of FIT generation capacity connected to its distribution system. To date, FFPC has been able to accommodate all microFIT and FIT projects, and as such FFPC has not had to deny any applications due to capacity constraints within FFPC's control. FFPC is planning on increasing its capacity to connect renewable generation, by eliminating reverse power flow, measurement, protection and control constraints, at its transformer station.

To assess microFIT and FIT connection commitment and success, FFPC uses the measures "Annual % of Eligible Projects Connected" and "Annual % of Eligible Projects Rejected". The purpose of this measure is to quantify FFPC's level of commitment and physical ability to accommodate the connection of renewable generation, in accordance to Legislative and Regulatory requirements to facilitate the connection of renewable generation.

5.2.3.7.b.i. FFPC Performance History

The following table and graph represents FFPC's performance history since the inception of the feed-in-tariff program in 2010. Note that FFPC did not receive any formal FIT project connection applications during 2010 and 2012, and as such the score is set to Not Applicable (N/A).

microFIT Projects Processing	2010	2011	2012
Annual % of Eligible Projects Connected	100%	100%	100%
Annual % of Eligible Projects Rejected	0%	0%	0%

FIT Projects Processing	2010	2011	2012
Annual % of Eligible Projects Connected	N/A	100%	N/A
Annual % of Eligible Projects Rejected	N/A	0%	N/A

5.2.3.7.b.ii. Performance Trend & Assessment

To date FFPC has been able to accommodate the connection of all microFIT and FIT applications that have been received. FFPC anticipates reaching photovoltaic generation connection limits on several of its distribution feeders over the 2014 to 2018 planning period. As such, FFPC is planning to invest in renewable enabling improvements at it its transformer station that will increase connection capacity. Accommodating the connection of renewable energy has had a material impact on FFPC's DS Plan, and $167k of capital investments are planned over the planning period to increase connection capacity. Without the planned capital investments, FFPC expects that its renewable generation connection performance to deteriorate as applications would be rejected due to capacity limitations. Refer to Section 5.4.3 for a detailed discussion regarding FFPC system limitations and corresponding renewable enabling improvements. FFPC does not have any industry statistics to compare its performance to at this time.

5.2.3.8 Financial Performance Measures

5.2.3.8.a. Liquidity Measure - (Current Assets/Current Liabilities)

FFPC's measure for the ability to pay off short term debt obligations is the commonly used Assets to Liabilities ratio, as per RRR filings. The measure is calculated as Current Assets divided by Current Liabilities. The higher the ratio, the higher the margin of safety for covering short term debt obligations.

5.2.3.8.a.i. Performance History

RRR Reported Financial Ratios	2005	2006	2007	2008	2009	2010	2011	2012
Current Ratio (Current Assets/Current Liabilities)	3.50	4.65	4.82	3.96	3.30	4.11	4.97	2.67

5.2.3.8.a.ii. Performance Trend & Assessment

FFPC long term objective is to maintain its "Current Assets / Current Liabilities" ratio well above 1. FFPC has a good history of being able to meet short term debt obligations.

5.2.3.8.b. Leverage - Total Debt (Includes short-term and long term debt) to Equity Ratio

FFPC's measure of what proportion of equity and debt is used to finance its assets is Total Debt / Total Equity. In the interest of long term minimization of customer rates, FFPC's historic operating strategy has been to avoid debt, to avoid passing on the associated interest expense to consumers. As such, FFPC still operates without the incurrence of any debt.

5.2.3.8.b.i. Performance History

RRR Reported Financial Ratios	2005	2006	2007	2008	2009	2010	2011	2012
Debt to Equity Ratio (Total Debt/Total Equity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

5.2.3.8.b.ii. Performance Trend & Assessment

FFPC's performance trends reflect operating with no debt and as such the numerator of this ratio is (0), resulting in a zero (0) ratio. FFPC's performance history is aligned with its rate minimization philosophy of operating without debt, thereby not passing on debt related interest carrying charges to consumers.

5.2.3.8.c. Profitability - Financial Statement Return on Equity

FFPC's key measure of profitability is its Financial Statement Return on Equity (Comprehensive Income/Total Equity). FFPC operates under a zero-percent rate-of-return business model to uphold the

requirements of the 1905 Historic Power Agreement on behalf of the residents and small businesses of the Town of Fort Frances. As such, FFPC's target ROE is 0% so not to violate "Commercialization" clauses of the agreement.

5.2.3.8.c.i. Performance History

RRR Reported Financial Ratios	2005	2006	2007	2008	2009	2010	2011	2012
Financial Statement Return on Equity (Net Income/Shareholder Equity)	0.34%	1.28%	0.96%	-0.29%	-1.03%	0.30%	-0.10%	-5.93%

5.2.3.8.c.ii. Performance Trend & Assessment

For the period 2005 to 2011, FFPC was able to achieve a sufficient rate-of-return in alignment with its target of zero percent (0). For the fiscal year 2012; however, FFPC was not able to achieve its target with a recorded shortfall of -5.93%. As FFPC does not have a "profit margin buffer", any shortfalls from its target of zero percent (0%) result in recorded deficits, whereas if FFPC operated for profit, the shortfall would only result in a reduction in profit. FFPC has embraced undertaking a Cost of Service Rate rebasing, due largely to the 2012 recorded shortfall, so as to avoid continued financial losses that undermine its viability. Furthermore, FFPC needs to realign its revenue requirement to address the need of increasing its staffing resources, to realign its business with the current demands of the industry. The current level of effort exerted by FFPC's salaried staff is not sustainable and as such FFPC is realigning its revenue requirement to fund additional resources (the addition of a Technical Customer Service Representative to staff, as well as more necessary services from third party service providers including Human Resources, Legal and IT expertise). As FFPC is not a profit driven but rather viability driven utility, FFPC was able to forgo raising its rates through the COS rebasing process, by postponing the rebasing from 2011 to 2014. FFPC is now required to realign its rates to better reflect the needs of its current operating conditions, as opposed to those of 2006, when FFPC completed its last rate rebasing.

5.3 Asset Management Process

Over the last few years, FFPC has worked extensively on formalizing its asset management process and on preparing its first formal asset management plan. FFPC and its predecessors had been managing distribution assets in the Town of Fort Frances since the early 1900's, long before the electrification of the Province as a whole occurred. Although FFPC has extensive experience managing assets, historically a formal process or plan was never documented. As such, this is FFPC's first attempt at formally documenting its Asset Management Process in alignment with the criteria set out in Chapter 5 of the March 28, 2013 released "Consolidated Distribution System Plan Filing Requirements". FFPC is very pleased with the OEB's impetus for distributors to develop DS Plans. FFPC believes that its newly developed asset management and capital planning processes, which are at the heart of the DS Plan, will bring tremendous future value to its customers. The initiative has allowed FFPC to transition from reactive short term planning and historic budgeting practices, to proactive long range planning and asset condition based budgeting.

5.3.1 Asset Management Process Overview

5.3.1.1 Asset Management Process Objectives

The overall objectives of FFPC's asset management process are to:

1. Enable wise decision making with respect to balancing cost, reliability and risk
2. Align spending decisions with corporate objectives
3. Enable multiyear planning based on rigorous data driven processes

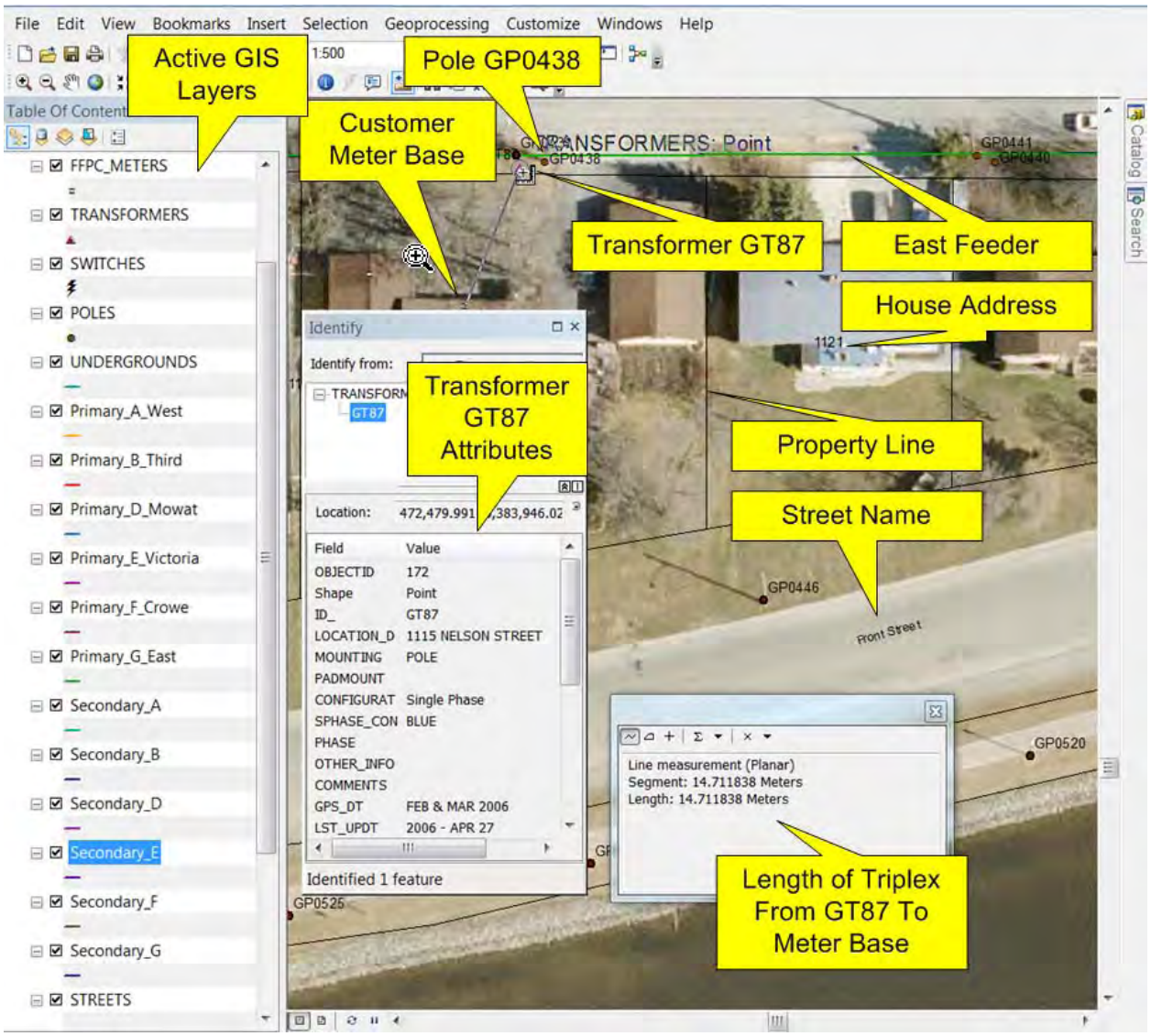
Refer to section 5.4.2 for details regarding FFPC's Vision, Mission, Values and planning objectives.

5.3.1.2 Integration of Geographic Information System into Asset Management

In 2005 FFPC invested in a Geographic Information System (GIS) and formally kicked-off gathering extensive information from its distribution system assets and general plant assets. The field information gathered combined with available office records essentially generated FFPC's asset register. To date FFPC has gathered key asset attribute information from all of its Transformers, Poles, Pole Attachments (including Third Party Attachments), Primary Overhead Conductors (Feeders), Primary Underground Conductors, Switches, Smart Meters, Fleet Vehicles, and from Key Transformer Station Components.

Other supporting records have also been imported into the tool such as; property data; customer contact information; zoning and property lines; street names and object specific files such as pictures. The tool is also used extensively in day-to-day operations to assist in capital, maintenance, and operations work planning; the processing of customer inquiries; and the costing of jobs and projects.

The following screen caption is a very simple illustration of various high level data contained in FFPC's GIS system:



In 2008, FFPC also developed a comprehensive system for compliance with the requirements of Ontario Regulation 22/04 (O.Reg. 22/04) - "Electrical Distribution System Safety", as well as with the Distribution System Code Appendix C - "Minimum Inspection Requirements". The compliance system was also built on FFPC's asset register contained in the GIS system. The asset register has allowed FFPC to transition from generic inspection logs to very detailed asset specific inspection logs. For example; the pole inspection form contains an entry for each and every pole that FFPC owns. Thus FFPC has inspection data from every individual asset as opposed to only a listing of identified deficiencies from the distribution system in general. The main modules of the compliance system that FFPC developed include FFPC's; Maintenance Inspection Program; Purchasing and Equipment Approval; Approval of Plans, Drawings and Specifications for Installation Work; and Construction Verification Program.

Since the implementation of the compliance system, FFPC has received very favourable results from ESA Regulation 22/04 Compliance audits, as well as from ESA Due Diligence Inspections. FFPC now has a

solid foundation from which data driven decisions can be made with respect to the upkeep of its electrical distribution system.

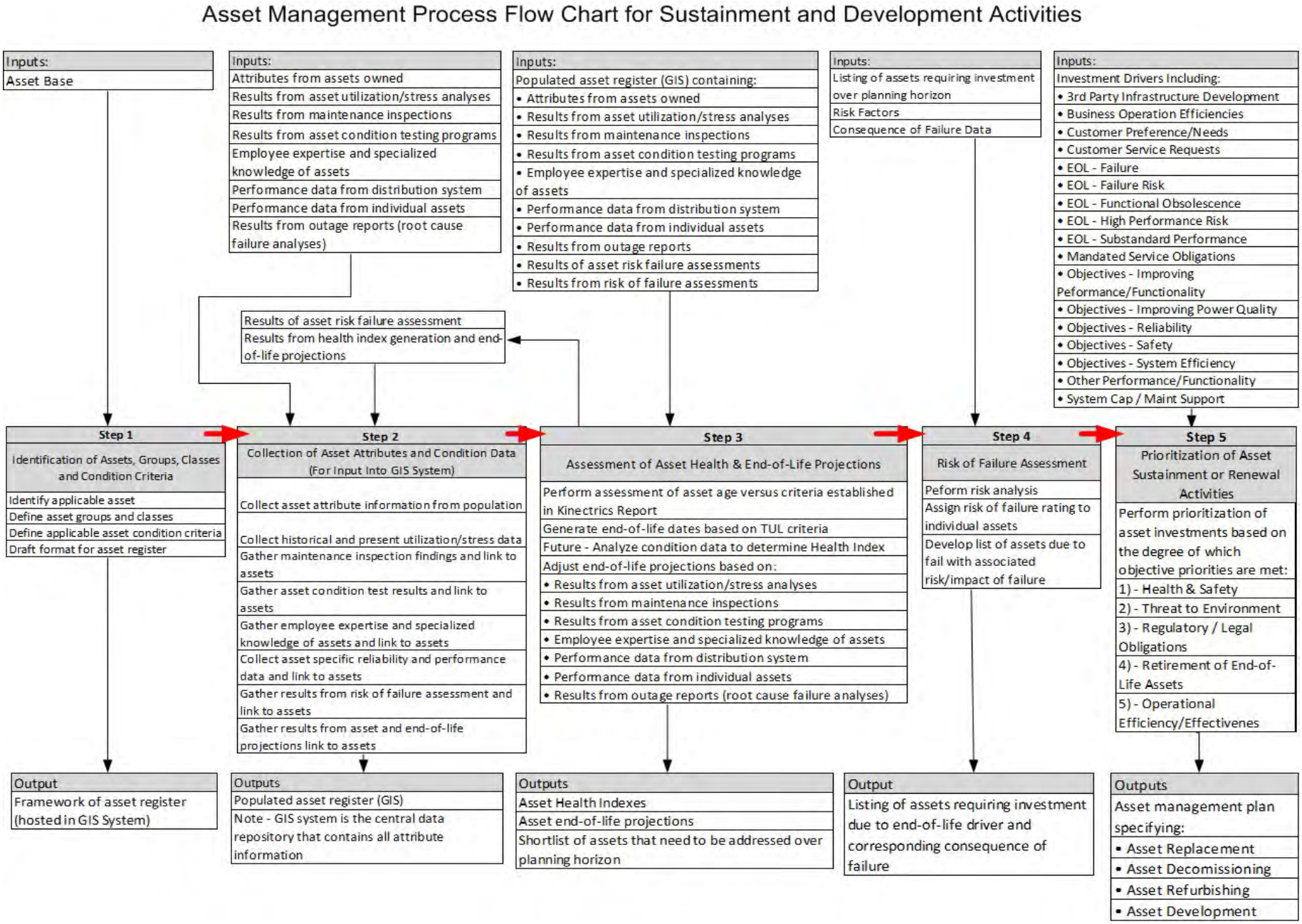
5.3.1.3 FFPC Bottom up Asset Specific Approach to Asset Lifecycle Management

The wealth of asset knowledge combined with the integration of inspection and condition testing process, has enabled FFPC to adopt an asset specific approach to asset management. FFPC now has oversight of virtually every individual asset, with insight into its age, overall health, operating conditions, projected failure date, impact of failure and replacement cost. The maintenance inspection process and condition testing process offer insight into the health of every asset. An asset's health is based on its relative age compared to industry established life expectancies, as well as on information that quantifies its operating environment. Assessing age and operating environment allow for the probability of failure to be assigned. Based on this approach, FFPC has developed a profile of the order in which assets are expected to fail, categorized by asset type. The year during which an asset is expected to fail due to exceeding its failure risk tolerance is called its "Adjusted End-of-Life" (AEOL). The AEOL profile of assets drives FFPC's pace of capital reinvestment needs for sustainment or development activities (also referred to as asset lifecycle management).

The asset data contained in the GIS system combined with FFPC's maintenance program (inspections and condition testing), are the heart of the Asset Management Process. In summation, the asset management process can be boiled down to two main modules that complement one another:

1. Process for Managing Asset Sustainment and Development Activities
2. Process for Managing the Operation and Maintenance Activities

5.3.1.4 Asset Management Process Overview Flow Chart



5.3.1.4.a. Asset Management Process Flow for Sustainment & Development Activities - Recipe Format

Step 1
Identification of Assets, Groups, Classes and Condition Criteria
Identify applicable assets
Define asset groups and classes
Define applicable asset condition criteria
Draft format for asset register
Inputs:
Asset Base
Output
Framework of asset register (hosted in GIS System)

Step 2
Collection of Asset Attributes and Condition Data (For Input Into GIS System)
Collect asset attribute information from population
Collect historical and present utilization/stress data and link to assets
Gather maintenance inspection findings and link to assets
Gather asset condition test results and link to assets
Gather employee expertise and specialized knowledge of assets and link to assets
Collect asset specific reliability and performance data and link to assets
Gather results from risk of failure assessment and link to assets
Gather results from asset end-of-life projections and link to assets
Inputs:
Attributes from assets owned
Results from asset utilization/stress analyses
Results from maintenance inspections
Results from asset condition testing programs
Employee expertise and specialized knowledge of assets
Performance data from distribution system
Performance data from individual assets
Results from outage reports (root cause failure analyses)
Inputs From Step 3
Results of asset risk failure assessment
Results from health index generation and end-of-life projections
Outputs
Populated asset register (GIS)
Note - GIS system is the central data repository that contains all attribute and condition information

Step 3
Assessment of Asset Health & End-of-Life Projections
Perform assessment of asset age versus criteria established in Kinectrics Report
Generate end-of-life dates based on TUL criteria
Analyze condition data to determine Health Index
Adjust end-of-life projections based on:
• Results from asset utilization/stress analyses
• Results from maintenance inspections
• Results from asset condition testing programs
• Employee expertise and specialized knowledge of assets
• Performance data from distribution system
• Performance data from individual assets
• Results from outage reports (root cause failure analyses)
Inputs:
Populated asset register (GIS) containing:
• Attributes from assets owned
• Results from asset utilization/stress analyses
• Results from maintenance inspections
• Results from asset condition testing programs
• Employee expertise and specialized knowledge of assets
• Performance data from distribution system
• Performance data from individual assets
• Results from outage reports
• Results of asset risk failure assessments
• Results from risk of failure assessments
Outputs
Asset Health Indexes
Asset end-of-life projections
Shortlist of assets that need to be addressed over planning horizon

Step 4
Risk of Failure Assessment
Perform risk analysis
Assign risk of failure rating to individual assets
Develop list of assets due to fail with associated risk/impact of failure
Inputs:
Listing of assets requiring investment over planning horizon
Risk Factors
Consequence of Failure Data
Output
Listing of assets requiring investment due to end-of-life driver and corresponding consequence of failure

Step 5
Prioritization of Asset Sustainment or Renewal Activities
Perform prioritization of asset investments based on the degree of which objective priorities are met:
1) - Health & Safety
2) - Threat to Environment
3) - Regulatory / Legal Obligations
4) - Retirement of End-of-Life Assets
5) - Operational Efficiency/Effectiveness
Inputs:
Investment Drivers Including:
• 3rd Party Infrastructure Development
• Business Operation Efficiencies
• Customer Preference/Needs
• Customer Service Requests
• EOL - Failure
• EOL - Failure Risk
• EOL - Functional Obsolescence
• EOL - High Performance Risk
• EOL - Substandard Performance
• Mandated Service Obligations
• Objectives - Improving Performance/Functionality
• Objectives - Improving Power Quality
• Objectives - Reliability
• Objectives - Safety
• Objectives - System Efficiency
• Other Performance/Functionality
• System Capital / Maintenance Support
Outputs
Asset management plan specifying:
• Asset Replacement Projects
• Asset Decommissioning Projects
• Asset Refurbishing Projects
• Asset Development Projects

5.3.1.4.b. Asset Management Process Explanation for Sustainment and Development Activities

FFPC's approach to managing the sustainment and development of its assets can be broken down into five logical steps.

Step 1 - Identification of Assets, Groups, Classes and Condition Data

FFPC's first step towards implementing a systematic data driven asset management process was to identify and quantify the assets that are within FFPC's scope to manage. Once the assets were quantified, FFPC developed a listing of key asset attributes, by asset type, to establish the data sets required to support data driven asset management decisions. FFPC's asset data sets can be broken into two categories; physical attribute data and condition data.

For example, typical physical attribute data includes; the type of asset (equipment type); its location; age; rating; or configuration. Arguably the most important attribute from this data set with respect to asset management is the "age" of the asset. The basic knowledge of the age profile of assets is a very good high level tool for estimating future expenditure requirements. The age profile of assets is a fundamental driver of investments and is a good starting point for prioritizing investments.

This step essentially creates the framework of the asset register that is required to be populated. It should be noted that FFPC is working towards having all asset attribute and condition data linked to the assets themselves within the GIS system. For example, for a typical pole FFPC now has the pole properties stored in the GIS such as it height, class, location, replacement cost and age, as well as condition data has been linked to it, such as the results of the last "hammer test" for structural integrity or of the last general inspection findings. In future iterations of the DS Plan FFPC, also plans to link risk ratings, health indexes and consequence of failure data to all individual assets.

Step 2 - Collection of Asset Attributes and Condition Data

Once the framework for necessary data required to manage assets has been established, the next logical step is to compile a listing of the population of assets owned, and to gather corresponding asset attribute information including condition and performance data. This step essentially generates a populated asset register.

FFPC has also compiled a listing of typical replacement costs for most common asset types and "replacement cost" is now an available attribute contained within the GIS based asset register.

Assets deteriorate as a function of time, as a function of their operating conditions and as a function of their physical environment. As such, FFPC's approach to asset management utilizes asset age, complimented by asset condition data. FFPC uses condition data to try and understand the operating conditions and environment of assets. This enables more accurate predictions of when assets will reach the end of their useful life, based on how quickly they are deteriorating. FFPC's key sources of condition data are the results from its maintenance inspection program, as well as the results from condition

testing programs. In addition to this, FFPC also utilizes available performance data and the results from outage root cause failure reports.

The output of this step is a populated asset register that contains all pertinent attribute and condition data. The populated asset register enables data analysis to be performed on individual assets or on asset groups or classes.

Step 3 - Assessment of Asset Health & End-of-Life Projections

FFPC performs an analysis on all of its asset types by comparing the age of assets relative to the "Typical-Useful-Life" (TUL) standards established in the July 8, 2010 "Kinectrics Asset Depreciation Study for the Ontario Energy Board" ("Kinectrics Report"). FFPC then performs further analyses to determine how available asset condition data affects the longevity of individual assets. Condition data sources include inspection results, condition testing results, asset performance data, employee expertise, root cause failure data from outage reports and known manufacturer defect information.

Utilizing these inputs, FFPC adjusts the "Typical-Useful-Life" expectancy of individual assets based on assessing the health of individual assets. Favourable condition data extends the life expectancy of assets and unfavourable condition data decreases the life expectancy, relative to the normal TUL's established in the Kinectrics Report. The resulting end-of-life estimations are referred to as "Adjusted End-of-Life" (AEOL) projections. The AEOL value profile for asset classes essentially generates a listing that reflects FFPC's best guess as to the order in which assets will fail.

The life expectancy adjustments are currently performed based on the judgment and expertise of knowledgeable staff. FFPC plans to develop a more definitive set of criteria that underpin life expectancy adjustments in future iterations of the process.

The AEOL profile for each asset class is updated annually to incorporate the latest available inspection, condition testing and performance data results. The end-of-life profile of assets allows FFPC to focus on the portion of assets that require special attention over the planning horizon. In other words, it allows FFPC to focus its attention on the assets that demand attention.

With FFPC's replacement cost data available at the asset level, FFPC is able to quickly and easily generate high level cost projections for long range planning purposes.

Step 4 - Risk of Failure Assessment

After establishing end-of-life projections for individual assets, the next step is to assign a criticality of failure to the assets that are projected to fail over the planning horizon. In future iterations of the DS Plan, FFPC will assign a criticality rating to all of individual assets, not just those projected to fail over the planning horizon. FFPC uses the following risk factors when performing its failure assessment: impact

on the health and safety of employees and the public; number of customers affected; location; accessibility; environmental impact; impact on reliability; cost of failure. The output of this step provides management with a listing of projected asset failures (high probability of failure) over the planning horizon, and an understanding of the impact of individual asset failures.

Step 5 - Prioritization of Asset Sustainment or Renewal Activities

This step is essentially the decision making engine or capital expenditure planning process, for the purpose of prioritizing long range investments and linking investment drivers to planned expenditures. The linking and prioritizing of investments essentially generates the foundation of a long range capital plan.

FFPC prioritizes investments or projects to the degree with which the following objectives are satisfied:

1. Ensuring that the health and safety of employees and the public is maintained
2. Eliminate or mitigate threats to the environment
3. Ensuring compliance to regulatory and legal obligations
4. Meeting the needs and preference of customers
5. Retiring assets that are at the end of their useful life
6. Improving operational efficiency and effectiveness

Steps 1 through 4 systematically identify assets that: are at the end of their service life; have failed; are due to fail (have a high risk of failure); are operating with substandard performance. These factors only represent a portion of drivers that need to be considered for capital planning. Steps 1 to 4 essentially encompass the management of asset lifecycles, which typically represents upwards of 70% of all capital expenditure requirements.

Step 5 holistically evaluates the impact of all investment drivers (not just lifecycle management) that FFPC must address as well including: customer service requests; other 3rd party infrastructure development requirements; mandated service obligations (accomplishment of regulatory requirements); expected changes in load or customer growth; achievement of corporate or strategic goals; achieving customer needs or expectations; and the achievement of regional planning activities.

The output of this step is a long range capital plan that specifies asset replacement, decommissioning, refurbishing and development projects to meet FFPC's business objectives.

5.3.1.5 Asset Management Process for Managing Maintenance Activities

FFPC's asset management process for managing maintenance activities can be broken down into the following three main programs:

1. Maintenance Inspection Program

- Includes asset condition testing program

2. Transformer Station Preventative Maintenance Program
    - Includes asset condition testing & analysis
3. Vegetation Management Program

The Maintenance Inspection Program and Transformer Station Preventative Maintenance Program provide key inputs for Step 2 - "Collection of Asset Attributes and Condition Data" of FFPC's Asset Management Process for Sustainment and Development Activities. The programs essentially provide asset specific condition data that is used to assess asset end-of-life projections.

5.3.1.5.a. Maintenance Inspection Program

FFPC has developed an extensive maintenance inspection program to meet the requirements of Ontario Regulation 22/04 Section 4 "Safety Standards", section 5 "When Safety Standards Met" and of the Ontario Energy Board's Distribution System Code Appendix C, "Minimum Inspection Requirements". Refer to Appendix 4 for FFPC's complete Maintenance Inspection Program.

5.3.1.5.b. Transformer Station Preventative Maintenance Program

FFPC has retained the services of Siemens Canada to perform annual maintenance inspections and asset condition testing of all major station components. All major components have been assigned to a three year maintenance schedule and asset condition assessments are performed annually due to the criticality of the station.

The following maintenance, testing and inspection schedule has been applied as per the recommendation of Siemens Canada:

Year 1 Inspection, Maintenance & Condition Analysis:

- OCB testing
- Relay testing
- Battery banks testing
- Yearly oil sampling (all assets containing oil - T1, T2 & OCB's)

Year 2 Inspection, Maintenance & Condition Analysis:

- Transformer T1 and associated equipment (tap changer, arrestors), T1 15 kV Breakers
- Battery banks testing
- Yearly oil sampling (all assets containing oil- T1, T2 & OCB's)

Year 3 Inspection, Maintenance & Condition Analysis:

- Transformer T2 and associated equipment (tap changer, arrestor), T2 15 kV Breakers
- Battery banks testing
- Yearly oil sampling (all - T1, T2 & OCB's)

The following schedule will be applied for the period 2014 to 2018

Year	Asset Management Schedule
2014	Year 1 Schedule
2015	Year 2 Schedule
2016	Year 3 Schedule
2017	Year 1 Schedule
2018	Year 2 Schedule

5.3.1.5.c. Vegetation Management Program

FFPC has a regular line clearing and tree trimming maintenance program. Using FFPC's GIS system, FFPC has divided its service territory into five zones. Each zone is cleared on a 5 year cycle, unless inspection results find higher risk areas that demand priority trimming.

5.3.1.5.d. Insulator Washing

FFPC does not have any issues with salt build-up or contamination of its insulators. As such, FFPC does not perform insulator washing as it is an unnecessary expense.

5.3.1.5.e. Infrared Thermography

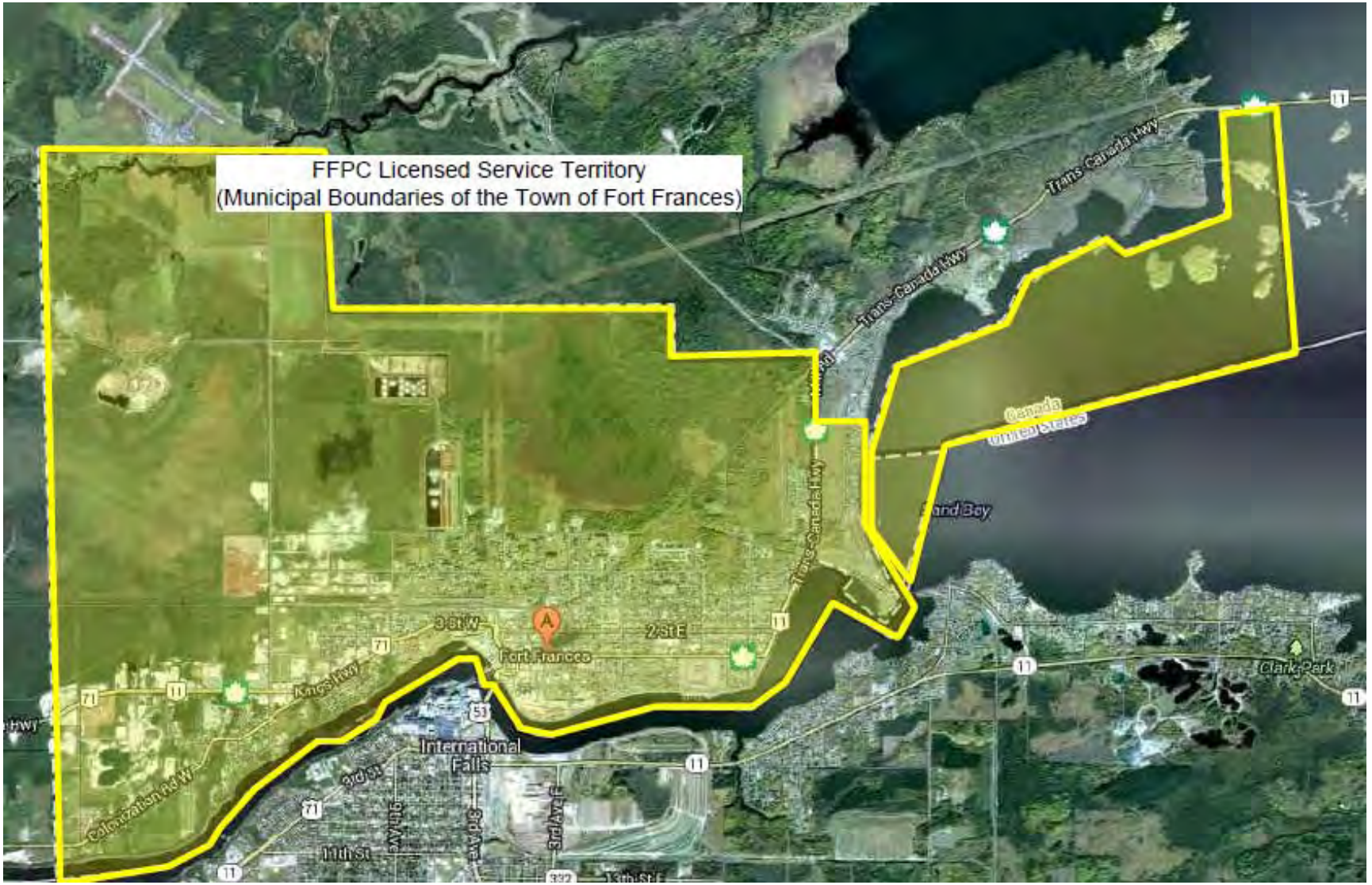
In the past, FFPC has hired a consultant to perform infrared thermography on overhead plant to identify "hot spots" and other general deficiencies. Virtually no hot spots or deficiencies were found, and as such it was recommended not to proceed with further testing as little value was recognized relative to the expense of the program.

5.3.2 Overview of assets managed

5.3.2.1 Licensed Distribution Service Territory

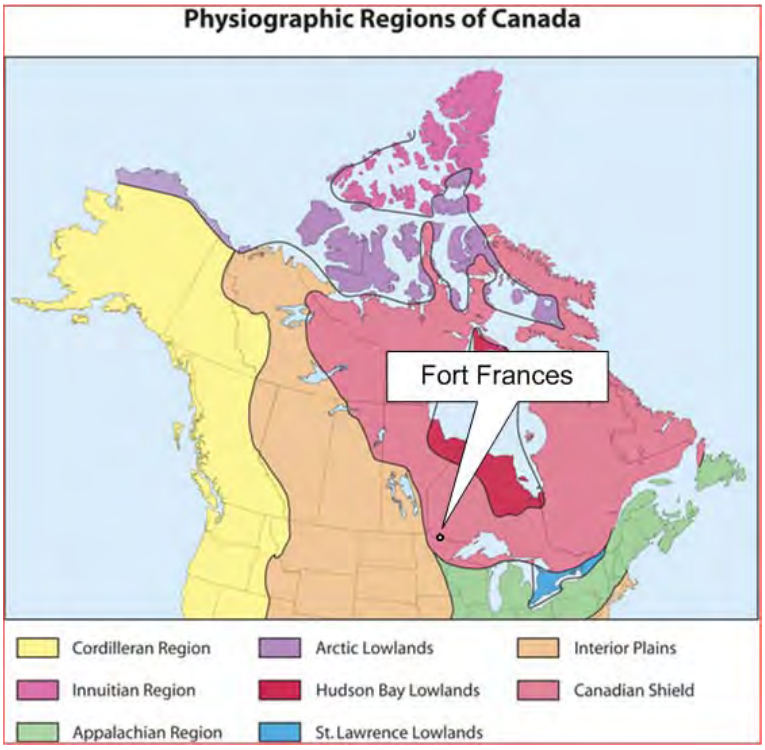
FFPC is licensed to distribute electricity within the municipal boundaries of the Town of Fort Frances. The Town is located approximately 300 km west of Thunder Bay, Ontario, approximately 250 km east of the Manitoba Border and is adjacent to the Town of International Falls, Minnesota. The Rainy River acts as the southern boundary of the community, and it is also the international boundary dividing Canada and the United States of America. The outlying service territory around Fort Frances is serviced by Hydro One Networks Inc (HONI) on the Ontario side, and by Minnesota Power and Lights on the Minnesota side. The following satellite picture illustrates FFPC's service territory and the Town of Fort Frances.

5.3.2.1.a. Map of FFPC Licensed Electrical Distribution Service Territory



5.3.2.1.b. Physiographic Attributes of Service Territory

The Town of Fort Frances is located on the edge of the Canadian Shield as illustrated by the following Physiographic Map of Canada.



The following is a description of the properties of the Canadian Shield as per Wikipedia.

> *"The Canadian Shield, also called the Laurentian Plateau, or Bouclier Canadien (French), is a large area of exposed Precambrian igneous and high-grade metamorphic rocks (geological shield) that forms the ancient geological core of the North American continent (North American or Laurentia craton), covered by a thin layer of soil. It is an area mostly composed of igneous rock which relates to its long volcanic history. It has a deep, common, joined bedrock region in Eastern and central Canada and stretches North from the Great Lakes to the Arctic Ocean, covering over half of Canada; it also extends South into the Northern reaches of the United States. Human population is sparse, and industrial development is minimal, while mining is very prevalent."*

FFPC's distribution system is subjected to the harsh conditions related to the Canadian Shield, as well as it is also subjected to extreme weather conditions (cold weather extremes).

5.3.2.1.c. Weather Conditions

Weather conditions in Northern Ontario are considerably different from Southern Ontario conditions. Wikipedia describes the climate in Fort Frances as:

"Fort Frances has a relatively extreme humid continental climate with bitterly cold winters and temperate summers. Temperatures beyond 34 degrees C has been measured in all five late spring and summer months. Summer highs are comparable to Paris and the Los Angeles Basin coastline in California, whereas winter lows on average resemble southern Siberia and polar subarctic inland Scandinavia."

Conditions in Fort Frances are best described as cold winters with relatively short and hot summers. Temperature variations are best described as being extreme. Large swings in daily temperature impose considerable thermal stress on electrical distribution system components and contribute significantly to their degradation.

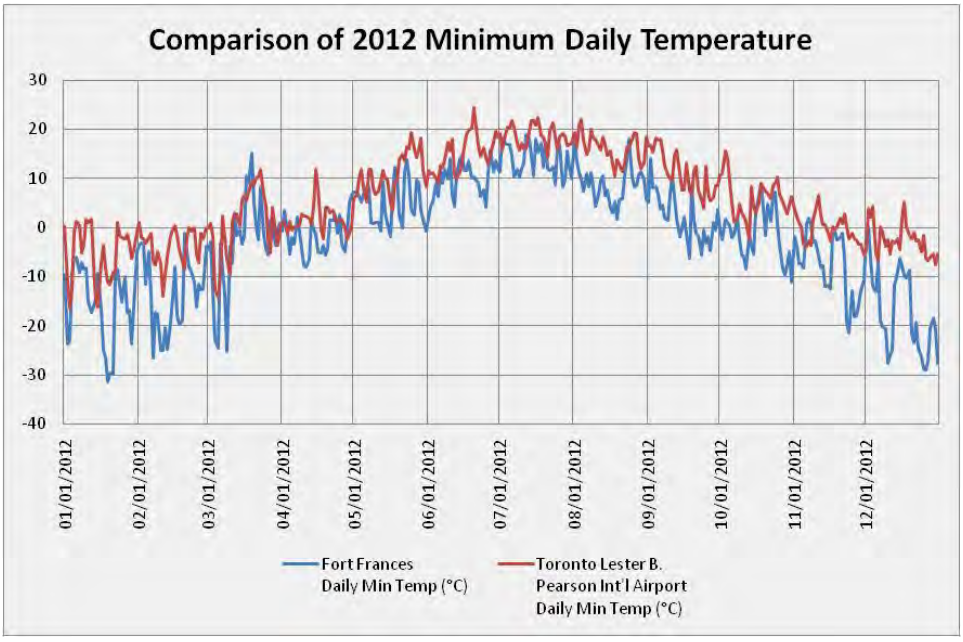
In general, consumers in the Northern Ontario require more electricity for heating related purposes rather than for cooling related purposes. The summer season in Fort Frances is also considerably shorter than that enjoyed in Southern Ontario. As such, the electricity consumption profile for Fort Frances is quite different from that of Southern Ontario.

The following graphs represent a comparison of key weather conditions of Fort Frances (measured at Airport) relative to Lester B. Pierson Airport. The information is based on Environment Canada weather station data which can be found for Fort Frances at:

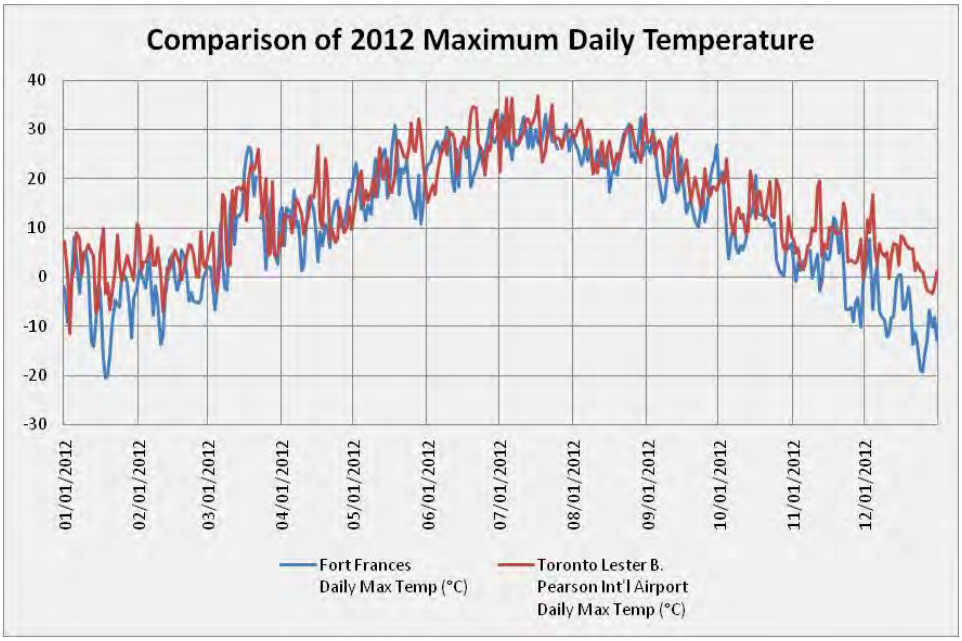
http://climate.weather.gc.ca/climateData/dailydata_e.html?StationID=46507

and for Lester B. Pierson International Airport at:

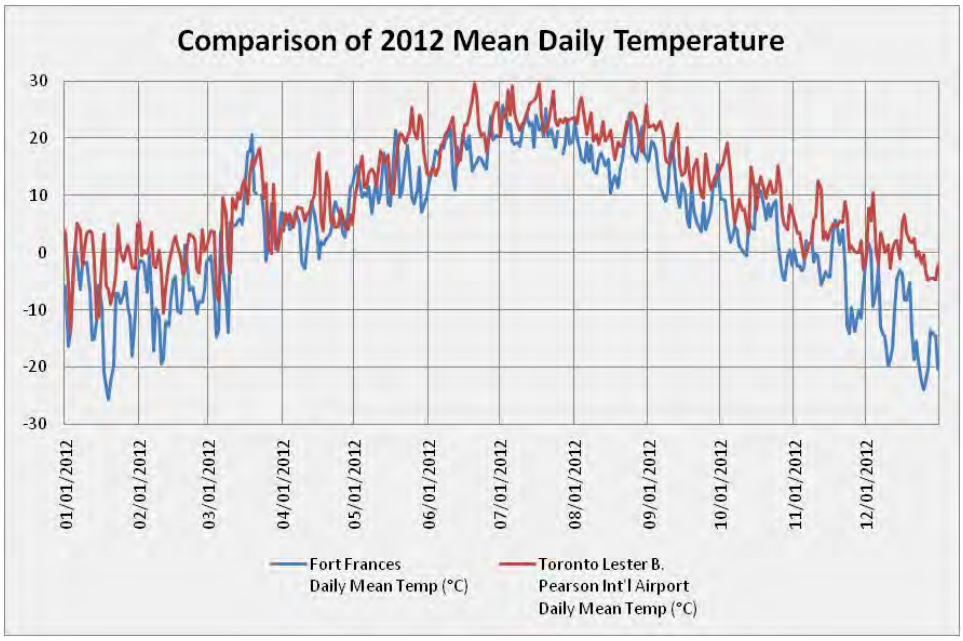
http://climate.weather.gc.ca/climateData/hourlydata_e.html?timeframe=1&Prov=ONT&StationID=5097&hlyRange=1953-01-01%7C2013-06-13&Year=2012&Month=6&Day=13&cmdB1=Go



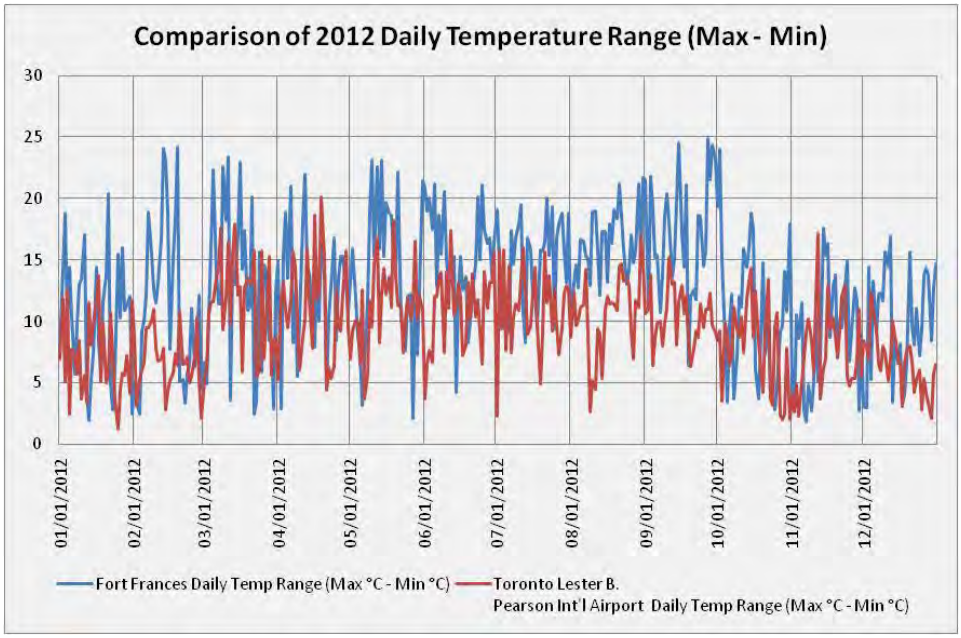
- Note the consistent pattern of daily lows being lower in Fort Frances
- Note the largest differential occurs during the winter months, illustrating extremely cold winters
- On average, Daily Minimum Temperatures are 7.4 °C cooler in Fort Frances



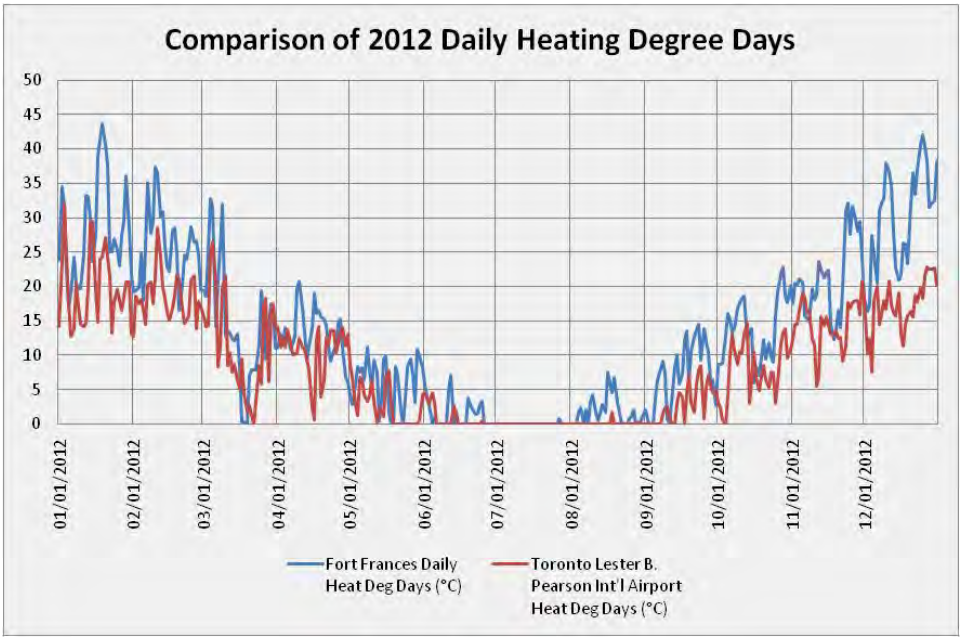
- Note that daily temperature highs track much closer than the daily temperature lows
- Note the largest differential again occurs during the winter months representative of extremely cold winters in Fort Frances
- Note that the summer time highs track fairly closely, although peaks are slightly higher at Lester B. Pierson Airport illustrating slightly warmer summers
- On average, Daily Maximum Temperatures are 4.0 °C cooler in Fort Frances



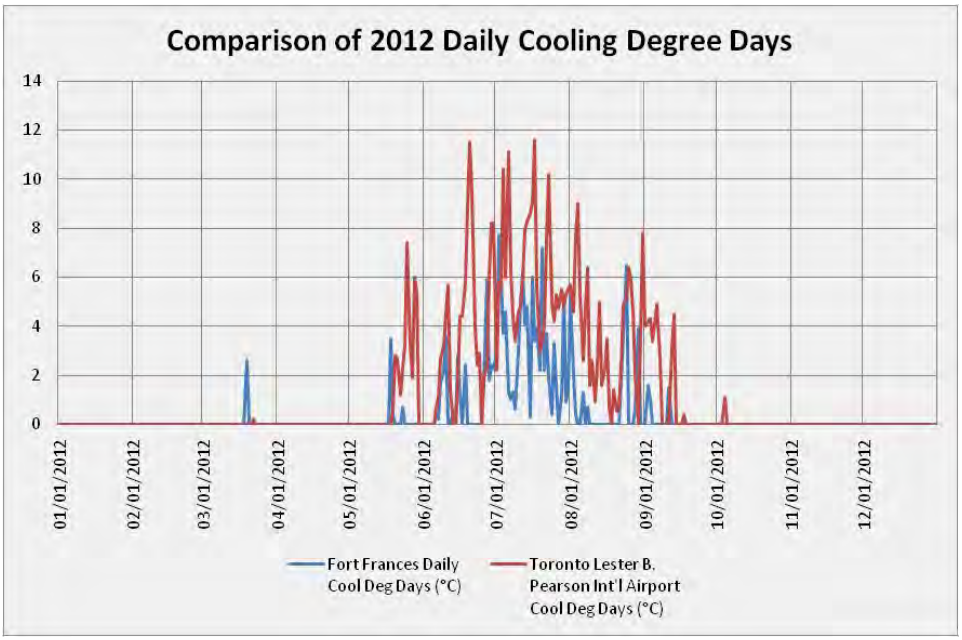
- Note that daily mean temperatures are consistently lower in Fort Frances
- Note that the largest differential occurs during the winter months
- On average, Daily Mean Temperatures are 5.7 °C cooler in Fort Frances



- Note that daily temperature variations are notably more extreme in Fort Frances
- On average, Daily Temperature fluctuations are 36% higher in Fort Frances



- Note that heating degree day demand is consistently higher in Fort Frances
- Notice the highest differential occurs over the winter months, illustrating extremely cold winters
- Notice that spring and fall seasons require more heating in Fort Frances
- Note that July is the only month in Fort Frances not requiring "heating" degrees (with the exception of one day)
- On average, heating degree day demand is 55% higher in Fort Frances



- Note that cooling degree day demand is considerably lower in Fort Frances over the summer months

- Note that the cooling season is considerably shorter in Fort Frances representative of a shorter summer.
- On average, cooling degree day demand is 66% lower in Fort Frances

5.3.2.1.d. Urban Versus Rural Service Territory

FFPC has chosen to treat its entire distribution service territory as "Urban" service territory, for the purpose of adhering to minimum inspection requirements as set out in Appendix C of the DSC. Appendix C defines "Urban" and "Rural" as per the following:

> *"Rural": Generally will be defined on a circuit or sub-circuit basis by each distributor, as areas with a customer density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the distributor may choose to treat some parts of its distribution system as urban though it is "rural" according to this definition.*
>
> *"Urban": Each distributor will define "Urban", or more populated areas, on a circuit or sub-circuit basis, as areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.*

FFPC is currently working on identifying customer to transformer and customer to feeder relationships; however, at the time of preparing this DS Plan these relationships are not yet known. From a system wide perspective, FFPC's customer density would fall in the "Rural" category, as it is 49.5 customers per kilometer of line, which is below the threshold of 60 customers per kilometer of line as illustrated by the following:

Customer Density = (Total Number of Customers) / (Total KM of Distribution Line)
= (3780) / 76.4
= 49.5 Customers / KM

As previously mentioned, FFPC has chosen to treat its customer density as being "Urban" and thereby to adhere to the more stringent requirements set out in the DSC.

5.3.2.1.e. Underground versus Overhead Distribution Plant

The majority of FFPC's distribution system consists of overhead conductor runs affixed to wood poles. Underground conductors are primarily found in newer developments, as well as at larger three-phase customer installations. Several years ago, FFPC undertook a significant effort to map out the dimensions and properties of its distribution system in a GIS system. The results of the mapping exercise state that FFPC owns and operates:

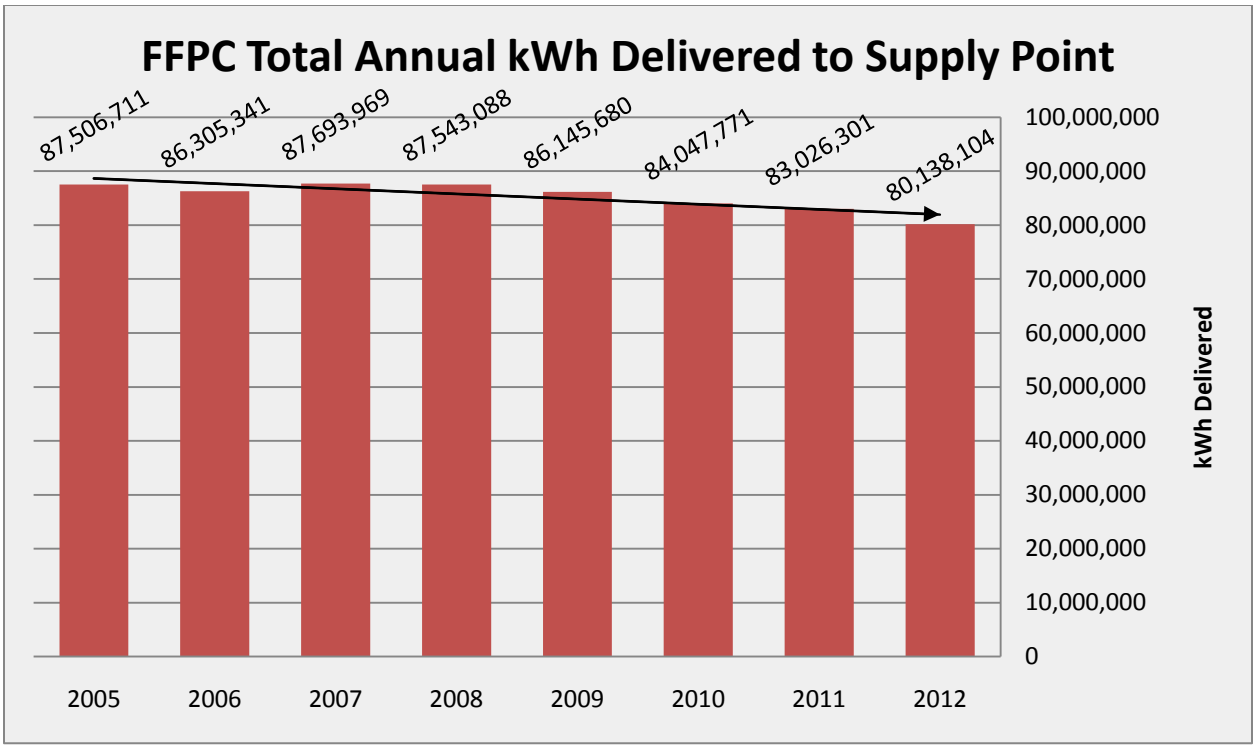
Type of Primary Power Line	Length in km	Units
Three Phase OH Primary Power Lines	46.3	km
Single Phase OH Primary Power Lines	19.5	km
Three Phase UG Primary Power Lines	6.2	km
Two Phase UG Primary Power Lines	0.5	km
Single Phase UG Primary Power Lines	3.9	km
Total	76.4	km

5.3.2.1.f. Local Economic Conditions

The Town of Fort Frances was built around a pulp and paper mill at the turn of the century, and this plant has historically been the single largest employer supporting the community. In 2009, the plant was owned and operated by Abitibi-Bowater, at which time the company filed for creditor protection, "CCAA." Since then, the operation has been largely curtailed and currently only 25% to 30% of all employees are still employed. Approximately 500 good paying positions have been lost, and this has had a significant impact on the local economy. Of the 500 positions lost, approximately 300 were lost during the spring and summer of 2013.

Although FFPC does not directly supply the manufacturing portions of the Pulp and Paper Mill (as it is transmission connected to HONI), FFPC does supply auxiliary support complexes including office buildings, parking lots, and warehouses. According to the billing history of the auxiliary support complexes, FFPC estimates that the continued curtailment of these facilities will equate to a direct loss of approximately 1.85% of FFPC's total customer load, based on 2012 consumption data. FFPC also anticipates that the mill's production curtailment and labour force layoffs will result in a drop in residential and commercial business load. FFPC estimates that the short term impact will be roughly three times the amount of load lost from servicing the auxiliary support complexes. In the event of prolonged production curtailments and labour force layoffs, FFPC estimates that by 2018 the impact on the community will be roughly five times that of the load lost from servicing the auxiliary support complexes.

There are many variables such as the Canadian Dollar to US Dollar exchange rate, which could have a significant impact on either the success or the demise of the plant, which FFPC cannot predict. Given the current state of the local economy, customer growth is not expected to be an investment driver over the rate horizon. The following graph illustrates FFPC's annual volume of electricity delivered to its supply point, transformer station Fort Frances MTS.



5.3.2.2 Summary of Assets Managed

FFPC owns and operates all electrical distribution assets necessary to distribute electricity to its customers throughout its licensed distribution service territory, including its own greater than 50 kV Transformer Station. The only exceptions to this are fourteen (14) Long Term Load Transfer customers that reside on the fringe of FFPC's service territory, which are currently physically connected to Hydro One Networks Inc.'s distribution assets. There are currently gaps between HONI and FFPC's infrastructure, such that the area between the two systems is not electrically serviced.

FFPC has organized its asset groupings according to the "Kinectrics Asset Depreciation Study for the Ontario Energy Board" ("Kinectrics Report"). The following table summarizes all of the significant assets managed by FFPC:

FFPC Summary of Assets Owned

		Asset Details			FFPC Assets			Kinectrics Useful Life		
Parent*	**#**	**Category| Component | Type**			**Count**	**Units**	**Average Age of Population (Years)**	**MIN UL**	**TUL**	**MAX UL**
OH	1	Fully Dressed Wood Poles	Overall		1776	Each	21.79	35	45	75
			Cross Arm	Wood	N/A			20	40	55
				Steel	N/A			30	70	95
	2	Fully Dressed Concrete Poles	Overall		N/A			50	60	80
			Cross Arm	Wood	N/A			20	40	55
				Steel	N/A			30	70	95
	3	Fully Dressed Steel Poles	Overall		N/A			60	60	80
			Cross Arm	Wood	N/A			20	40	55
				Steel	N/A			30	70	95
	4	OH Line Switch (Expressed as sets of 3 Phase Switches)			35	Each	24.34	30	45	55
	5	OH Line Switch Motor			N/A			15	25	25
	6	OH Line Switch RTU			N/A			15	20	20
	7	OH Integral Switches			N/A			35	45	60
	8	OH Conductors	Primary Conductor		224.2	km	33.77	50	60	75
			Secondary Conductor		114.8	km	28.00	25	35	40
	9	OH Transformers			629	Each	28.79	30	40	60
	10	OH Shunt Capacitor Banks			N/A			25	30	40
	11	Reclosers			N/A			25	40	55
TS & MS	12	Power Transformers	Overall		2	Each	38.00	30	45	60
			Bushing		12	Each	38.00	10	20	30
			Tap Changer		2	Each	38.00	20	30	60
	13	Station Service Transformer			1	Each	40.00	30	45	55
	14	Station Grounding Transformer			N/A	Each		30	40	40
	15	Station DC System	Overall		2	Each	23.00	10	20	30
			Battery Bank		2	Each	9.00	10	15	15

			Charger	2	Each	23.00	20	20	30
	16	Station Metal Clad Switchgear	Overall	11	Each	45.00	30	40	60
			Removable Breaker	11	Each	45.00	25	40	60
	17	Station Independent Breakers		1	Each	67.00	35	45	65
	18	Station Switch		5	Each	41.00	30	50	60
	19	Electromechanical Relays		34	Each	36.00	25	35	50
	20	Solid State Relays		N/A	Each		10	30	45
	21	Digital & Numeric Relays		8	Each	1.50	15	20	20
	22	Rigid Busbars		3	Each	36.00	30	55	60
	23	Steel Structure		1	Each	36.00	35	50	90
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		N/A			60	65	75
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		N/A			20	25	25
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		N/A			20	25	30
	27	Primary Non-TR XLPE Cables in Duct		N/A			20	25	30
	28	Primary TR XLPE Cables Direct Buried		N/A			25	30	35
	29	Primary TR XLPE Cables in Duct		30.7	km	27.07	35	40	55
	30	Secondary PILC Cables		N/A			70	75	80
	31	Secondary Cables Direct Buried		3.8	km	28.00	25	35	40
	32	Secondary Cables in Duct		N/A			35	40	60
	33	Network Transformers	Overall	N/A			20	35	50
			Protector	N/A			20	35	40
	34	Pad-Mounted Transformers	Single Phase	215	Each	27.70	25	40	45
			Three Phase	38	Each	20.05	25	40	45
	35	Submersible/Vault Transformers		N/A			25	35	45
	36	UG Foundation		170	Each	27.52	35	55	70
	37	UG Vaults	Overall	N/A			40	60	80
			Roof	N/A			20	30	45
	38	UG Vault Switches		N/A			20	35	50
	39	Pad-Mounted Switchgear		N/A			20	30	45
	40	Ducts		23.5	km	27.95	30	50	85
	41	Concrete Encased Duct Banks		1.9	km	33.46	35	55	80

	42	Cable Chambers		5	Each	20.40	50	60	80
S	43	Remote SCADA		N/A			15	20	30
General Plant	1	Office Equipment		Various	Each	Various	*5*	*10.0*	*15*
	2	Vehicles	Trucks & Buckets	7	Each	8.00	*5*	*10.0*	*15*
			Trailers	2	Each	26.00	*5*	*12.5*	*20*
			Vans	N/A			*5*	*7.5*	*10*
	3	Administrative Buildings		1	Each	45.00	*50*	*62.5*	*75*
	4	Leasehold Improvements (Generator)		1	Each	5.00	*20*	*20.0*	*20*
	5	Station Buildings	Station Buildings	2	Each	39.0	*50*	*62.5*	*75*
			Parking	1	Each	24.00	*25*	*27.5*	*30*
			Fence	1	Each	42.00	*25*	*42.5*	*60*
			Roof	2	Each	39.00	*30*	*30.0*	*30*
	6	Computer Equipment	Hardware	Various	Each	Various	*3*	*4.0*	*5*
			Software	Various	Each	Various	*2*	*3.5*	*5*
	7	Equipment	Power Operated	Various	Each	Various	*5*	*7.5*	*10*
			Stores	N/A			*5*	*7.5*	*10*
			Tools, Shop, Garage Equip.	Various	Each	Various	*5*	*7.5*	*10*
			Measurement & Testing Equip	Various	Each	Various	*5*	*7.5*	*10*
	8	Communication	Towers	N/A			*60*	*65.0*	*70*
			Wireless	Various	Each	Various	*2*	*6.0*	*10*
	9	Residential Energy Meters		N/A			*25*	*30.0*	*35*
	10	Industrial/Commercial Energy Meters		N/A			*25*	*30.0*	*35*
	11	Wholesale Energy Meters		2	Each	5.00	*15*	*22.5*	*30*
	12	Current & Potential Transformer (CT & PT)		479	Each	Various	*35*	*42.5*	*50*
	13	Smart Meters		3966	Each	4.92	*5*	*10.0*	*15*
	14	Repeaters - Smart Metering		N/A			*10*	*12.5*	*15*
	15	Data Collectors - Smart Metering		7	Each	5.00	*15*	*17.5*	*20*

Note: For General Plant where TULs were not specified, FFPC has designated the midpoint between the Min UL and Max UL.

5.3.2.2.a. Available Asset Data to Support Asset Management Process

As previously discussed, the GIS system is the heart of FFPC's asset management process, as it is the central warehouse that contains all pertinent asset related data. FFPC's goal is to have its entire asset register contained in its GIS system, and to link all relevant available data to individual assets to support FFPC's asset management and capital planning processes. Over the planning horizon, FFPC is also planning to launch a new Work Order and Financial System, such that that all work history and costing data is tracked and directly linked to individual assets, to further enhance planning capabilities.

FFPC is currently working on linking individual assets to all corresponding relevant information or data sets. The completion of this initiative will provide FFPC with an invaluable tool enabling automated prioritizing of asset related investments with ease. The following summary table is an estimation of FFPC's progress towards the completion of the "GIS Initiative", in support of FFPC's asset management and capital planning processes:

Availability of Distribution System Asset Data in Support of Asset Management Process

Parent*	#	Asset Details			FFPC Assets Count	FFPC Assets Units	% of Assets Quantified	% Assets Mapped In GIS	% of Asset Attributes Linked	% Condition Data from Inspections Linked	% Condition Test Data Linked Data Collected	% Risk Data / Consequence of Failure Data Linked
		Category| Component | Type										
OH	1	Fully Dressed Wood Poles	Overall		1776	Each	100	>98	>93.8	100	100	20
			Cross Arm	Wood	N/A							
				Steel	N/A							
	2	Fully Dressed Concrete Poles	Overall		N/A							
			Cross Arm	Wood	N/A							
				Steel	N/A							
	3	Fully Dressed Steel Poles	Overall		N/A							
			Cross Arm	Wood	N/A							
				Steel	N/A							
	4	OH Line Switch			35	Each	100	100	100	100	N/A	25
	5	OH Line Switch Motor			N/A							
	6	OH Line Switch RTU			N/A							
	7	OH Integral Switches			N/A							
	8	OH Conductors	Primary Conductor		224.2	km	>95	>95	>90	100	N/A	0
			Secondary Conductor		114.8	km	>90	>70	>90	100	N/A	0
	9	OH Transformers			629	Each	100	100	100	100	N/A	20
	10	OH Shunt Capacitor Banks			N/A							
	11	Reclosers			N/A							
TS & MS	12	Power Transformers	Overall		2	Each	100	N/A	100	100	100	100
			Bushing		12	Each	100	N/A	100	100	100	100
			Tap Changer		2	Each	100	N/A	100	100	100	100
	13	Station Service Transformer			1	Each	100	N/A	100	100	100	100
	14	Station Grounding Transformer			N/A							
	15	Station DC System	Overall		2	Each	100	N/A	100	100	100	100
			Battery Bank		2	Each	100	N/A	100	100	100	100
			Charger		2	Each	100	N/A	100	100	100	100
	16	Station Metal Clad Switchgear	Overall		11	Each	100	N/A	100	100	100	100

			Removable Breaker	11	Each	100	N/A	100	100	100	100
	17	Station Independent Breakers		1	Each	100	N/A	100	100	100	100
	18	Station Switch		5	Each	100	N/A	100	100	100	100
	19	Electromechanical Relays		34	Each	100	N/A	100	100	100	100
	20	Solid State Relays		N/A							
	21	Digital & Numeric Relays		8	Each	100	N/A	100	100	100	100
	22	Rigid Busbars		3	Each	100	N/A	100	100	100	100
	23	Steel Structure		1	Each	100	N/A	100	100	100	100
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		N/A							
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		N/A							
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		N/A							
	27	Primary Non-TR XLPE Cables in Duct		N/A							
	28	Primary TR XLPE Cables Direct Buried		N/A							
	29	Primary TR XLPE Cables in Duct		30.7	km	>95	>90	>90	100	0	20
	30	Secondary PILC Cables		N/A							
	31	Secondary Cables Direct Buried		3.8	km	>80	0	25	100	0	10
	32	Secondary Cables in Duct		N/A							
	33	Network Transformers	Overall	N/A							
			Protector	N/A							
	34	Pad-Mounted Transformers	Single Phase	215	Each	100	>98	>95	100	0	20
			Three Phase	38	Each	100	>98	>95	100	0	35
	35	Submersible/Vault Transformers		N/A							
	36	UG Foundation		170	Each	100	>98	50	100	0	35
	37	UG Vaults	Overall	N/A							
			Roof	N/A							
	38	UG Vault Switches		N/A							
	39	Pad-Mounted Switchgear									
	40	Ducts		23.5	km	100	>95	50	N/A	N/A	20
	41	Concrete Encased Duct Banks		1.9	km	>95	>95	50	N/A	N/A	80
	42	Cable Chambers		5	Each	100	0	50	100	0	0
S	43	Remote SCADA		N/A							

Availability of General Asset Data in Support of Asset Management Process

Parent*	#	Asset Details		FFPC Assets		% of Assets Quantified	% Assets Mapped In GIS	% of Asset Attributes Linked	% Condition Data from Inspections Linked	% Condition Test Data Linked Data Collected	% Risk Data / Consequence of Failure Data Linked
		Category| Component | Type		Count	Units						
General Plant	1	Office Equipment		Various	Each	75	N/A	25	N/A	N/A	0
	2	Vehicles	Trucks & Buckets	7	Each	100	N/A	100	100	100	100
			Trailers	2	Each	100	N/A	100	100	100	100
			Vans	N/A							
	3	Administrative Buildings		1	Each	75	N/A	0	0	N/A	100
	4	Leasehold Improvements (Generator)		1	Each	100	N/A	0	0	N/A	10
	5	Station Buildings	Station Buildings	2	Each	100	N/A	0	0	N/A	100
			Parking	1	Each	100	N/A	0	0	N/A	100
			Fence	1	Each	100	N/A	0	0	N/A	100
			Roof	2	Each	100	N/A	0	0	N/A	100
	6	Computer Equipment	Hardware	Various	Each	100	N/A	0	0	N/A	0
			Software	Various	Each	>90	N/A	0	0	N/A	50
	7	Equipment	Power Operated	Various	Each	>80	N/A	0	0	N/A	0
			Stores	N/A							
			Tools, Shop, Garage Equip.	Various	Each	>60	N/A	0	0	N/A	0
			Measurement & Testing Equip	Various	Each	>80	N/A	0	0	N/A	0
	8	Communication	Towers	N/A							
			Wireless	Various	Each	100	N/A	0	0	N/A	0
	9	Residential Energy Meters		N/A							
	10	Industrial/Commercial Energy Meters		N/A							
	11	Wholesale Energy Meters		2	Each	100	0	100	100	100	100
	12	Current & Potential Transformer (CT & PT)		479	Each	100	0.95	25	0	0	0
	13	Smart Meters		3966	Each	100	>95	100	100	100	0
	14	Repeaters - Smart Metering		N/A							
	15	Data Collectors - Smart Metering		7	Each	100	100	100	N/A	N/A	100

5.3.2.2.b. History of FFPC's Electrical Distribution System

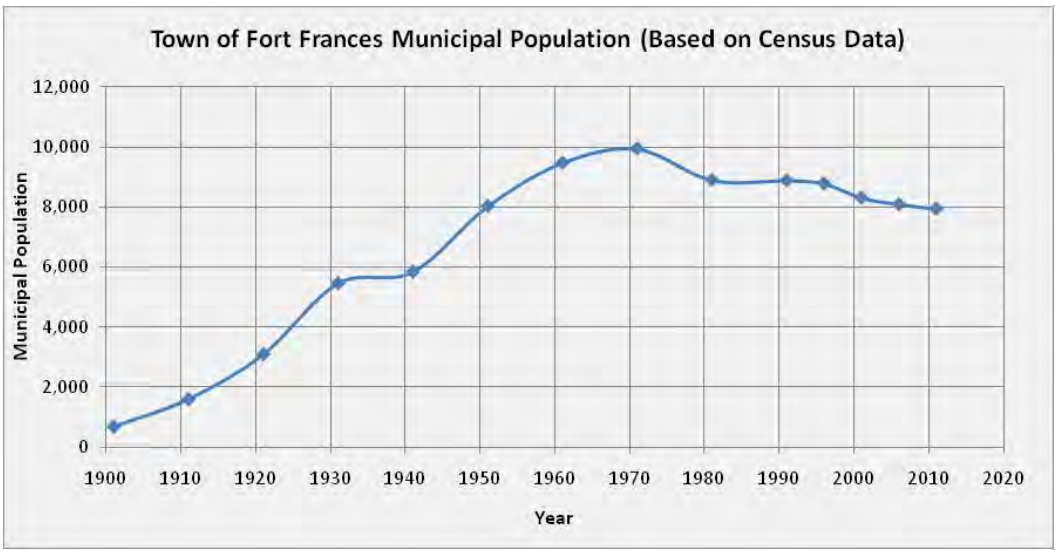
FFPC's DS Plan is largely influenced by the nature in which FFPC's distribution system evolved over the course of history. FFPC conducted a complete system wide rebuild and voltage conversion from the mid-1970s to the mid-1980s. During this period, FFPC converted its entire distribution system from a 2400 Volt system to a 7200 Volt system. All poles, transformers, pole line hardware were replaced as well as a transformer station was built to accommodate the new feeder voltages.

The voltage conversion project allowed FFPC to decommission five individual transformer stations that were located throughout Fort Frances, and to replace them with a single transformer station "Fort Frances MTS". To this day, FFPC relies on the station as its single point of supply, enabling delivery of electricity throughout all of FFPC's licensed service territory.

Due to the relatively narrow rebuild window, a large portion of FFPC's distribution system assets are of the same vintage including transformers, overhead primary and secondary conductors, as well as underground primary and secondary conductors and conduit. Over the last few decades FFPC has been operating in a maintenance mode; however, based on the results of its asset management and capital planning processes, a transition to a rebuild mode is required. Based on FFPC's asset management analyses, the distribution system as a whole has approximately 41.4% of service life remaining, which is considerably less than FFPC's target of 50%. FFPC expects to see a degree of "lumpiness" in future capital expenditure requirements, as large portions of assets reach the end of their useful service life over short time frames. One of FFPC's long range planning objectives is to smooth out the age distribution of its asset base, so that future capital expenditure requirements are more evenly distributed. FFPC recognizes that this may require several asset lifecycle iterations to accomplish.

Shortly after the completion of the system rebuild around 1985, FFPC began experiencing premature failures of wood poles due to manufacturing flaws in the treatment process. As a result of this, FFPC was forced to change pole suppliers and to continue on with its regular annual pole replacement program onwards to this day. Due to these premature failures, FFPC essentially smoothed out the age profile of its wood pole population. It is estimated that FFPC replaced approximately 42 poles per year, every year from the period 1972 until 2006. Historically FFPC did not use date nails or track installation dates of wood poles, and as such, a large portion of the poles could not have their actual date of manufacture verified during the GIS mapping initiative.

FFPC's rebuild window from the mid-1970s to mid-1980s also coincided with the period of highest customer growth in recent history. As a result, most of FFPC's newest subdivisions and other system expansions initiated by customer growth are also of 1970s and 1980s vintage. The Town of Fort Frances was essentially at its economic peak during this period. During the 1990s and 2000s, FFPC did not experience any significant customer growth and over the last few decades overall customer counts decreased gradually. The following graph illustrates the municipal population of the Town of Fort Frances, based on available Census Data:



It should be noted that the age distributions of the transformer station, distribution transformers, overhead conductors, underground conductors and smart meters are narrow, which will result in somewhat of a "tidal wave" affect as these assets approach the end of their useful service life.

5.3.2.2.c. Summary of Distribution System Configuration

FFPC's assets begin with its 115 kV to 12.47 kV step-down transformer station "Fort Frances MTS". Power transformers can have incremental power ratings based on the type of cooling system installed. Common power ratings are assigned using ONAN/ONAF cooling, where ONAN denotes "Oil Filled / Natural Convection / Air / Natural Circulation" and ONAF denotes "Oil Filled / Natural Convection / Air / Forced Circulation". As such, both station power transformers are rated at 20/25 MVA based on ONAN/ONAF cooling. As FFPC's power transformers are equipped with cooling fans, they are both rated for 25 MVA. The maximum station capacity is theoretically 50 MVA, based on the two power transformers operating in parallel; however, the station is designed to operate at up to 25 MVA which allows either transformer to service the entire customer load, thereby offering full redundancy in the event of a transformer outage or failure. As such, FFPC has assigned a total capacity of 25 MVA to its transformer station "Fort Frances MTS". Transformer redundancy is crucial for FFPC, as it underpins the overall reliability of electrical supply to distribution feeders. A power station transformer failure without redundancy could be devastating, possibly resulting in a loss of supply to feeders (affecting all customers) in the magnitude of days to weeks. Power transformers are typically not a stores stock item due to their high cost.

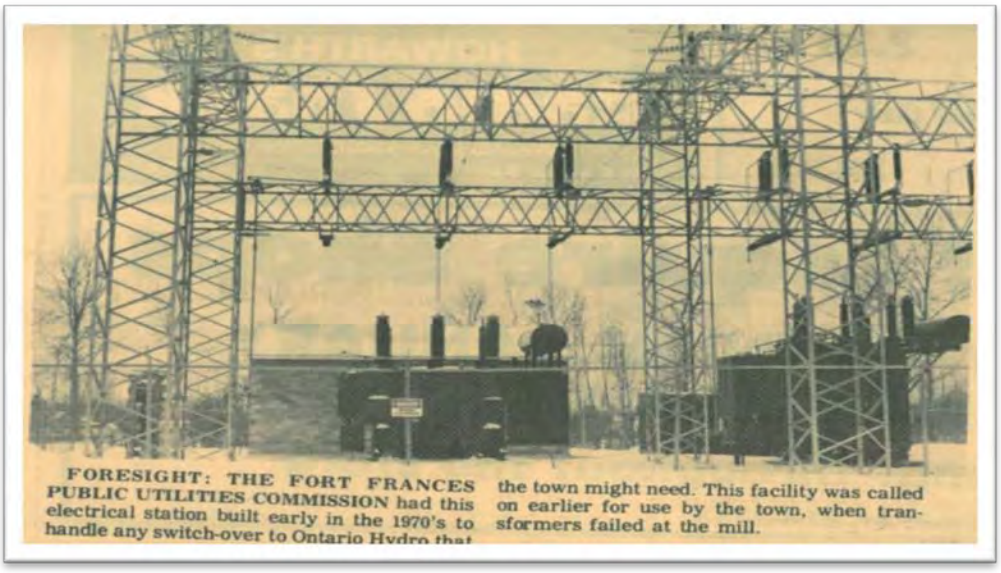
As previously mentioned, six 7.2/12.47 kV feeders propagate from the transformer station "Fort Frances MTS" throughout FFPC's licensed service territory, which is defined by the municipal boundaries of the Town of Fort Frances. Arithmetically, FFPC has a total 76.4 km of primary distribution plant. The following table is a summation of FFPC's distribution system configuration:

Fort Frances MTS Transformer & Feeder Properties					
Transformer Rating (ONAF)	**FFMTS Feeder Capacity Based on Ampacity Limit**	**Voltage (kV)**	**OH Primary Circuit Length (km)**	**UG Primary Circuit Length (km)**	**Total Primary Circuit Length (km)**
T1 - 20/25 MVA	West Feeder (A): 10 MW	7.2/12.47	19.49	4.42	23.91
	Mowat Feeder (D): 10 MW	7.2/12.47	5.42	0.45	5.87
	East Feeder (G): 10 MW	7.2/12.47	13.04	2.20	15.23
	Transformer T1 Circuits Subtotal		**37.94**	**7.07**	**45.01**
T2 - 20/25 MVA	Third Street Feeder (B): 10 MW	7.2/12.47	9.50	0.52	10.03
	Victoria Feeder (E): 10 MW	7.2/12.47	7.78	1.00	8.78
	Crowe Feeder (F): 10 MW	7.2/12.47	10.57	2.02	12.59
	Transformer T2 Circuit Subtotal		**27.86**	**3.55**	**31.40**
	System Total		**65.80**	**10.61**	**76.41**
Note: Fort Frances MTS Load Capacity = 25 MVA under normal fully redundant operating mode					

5.3.2.2.d. Transformer Station Assets

FFPC owns and operates one transformer station "Fort Frances MTS" (FFMTS), which is supplied from Hydro One Network Inc's (HONI) transformer station "Fort Frances TS" (FFTS), at a supply voltage of 115kV. HONI's transformer station "FFTS" is located directly across the street from FFPC's transformer station "FFMTS", and as such, a single 115kV span of transmission line connects the two stations. HONI's "FFTS" station is used to supply the outlying service territory, as an international transmission connection point between Ontario and Minnesota, as well as it supplies the Pulp and Paper Mill's production facility that is located within the Town of Fort Frances (the production facility is also connected at 115 kV). It is worth noting that HONI's local distribution system does not utilize 7.2/12.47 kV and as such FFPC's FFMTS was constructed to perform the voltage conversion. As a point of interest, 115 kV is commonly referred to as "sub-transmission" voltage. The power delivered through FFPC's FFMTS transformer station electrifies FFPC's entire distribution service territory, the Town of Fort Frances. As 115 kV is not a suitable distribution voltage (classified as transmission voltage), FFPC's power transformers within "FFMTS" step down the voltage to 7.2/12.47 kV, which is suitable for distribution.

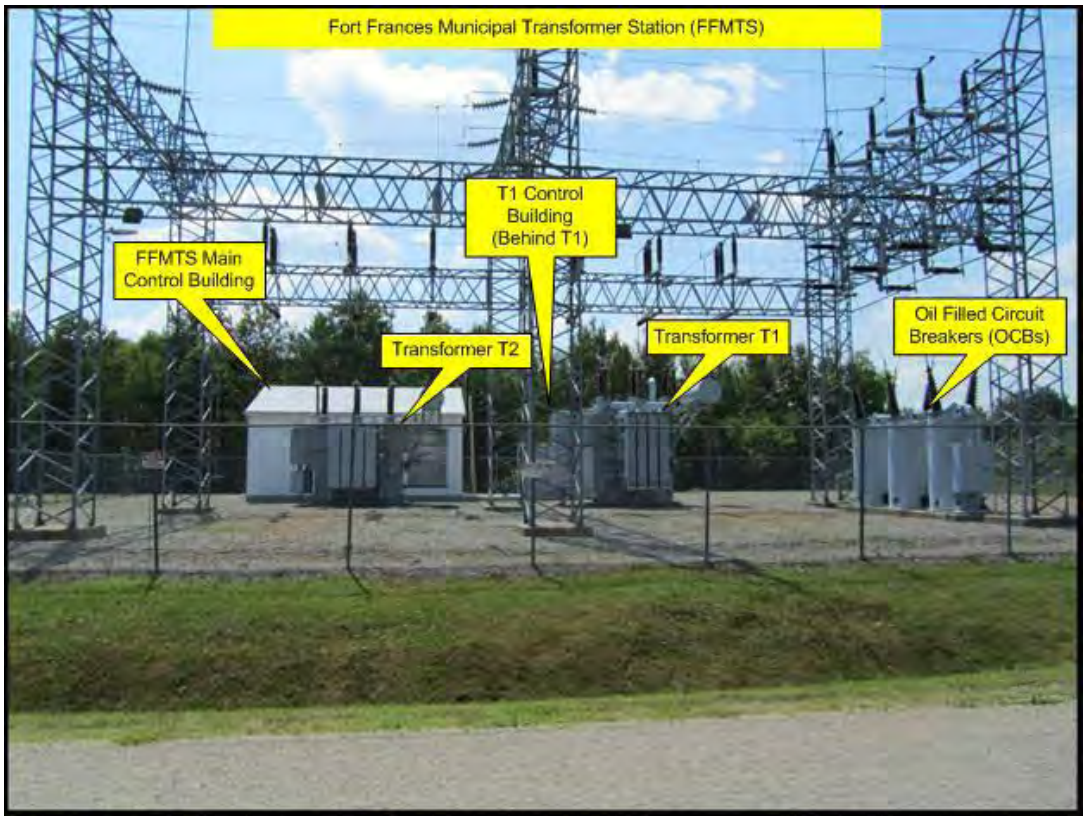
FFPC's 115 kV transformer station "FFMTS" was constructed in two phases during the 1970's and most of the station components including breakers, transformers, instrumentation, protection and controls are still of original vintage, lacking modern day functionality. In the early 1970's, the transformer station consisted of only one power transformer "T1" and a corresponding control building. By the late 1970's, a second power transformer "T2" and new main control building were installed for future load growth, as well as to offer full redundancy in the event that a station power transformer had to be taken out of service. The following newspaper clipping depicts FFMTS shortly after "T2" was installed in 1978.



FORESIGHT: THE FORT FRANCES PUBLIC UTILITIES COMMISSION had this electrical station built early in the 1970's to handle any switch-over to Ontario Hydro that the town might need. This facility was called on earlier for use by the town, when transformers failed at the mill.

It is important to note that due to the criticality of the transformer station, FFPC has contracted Siemens Canada to perform annual inspections and equipment condition testing, to monitor the health of core station assets. The asset condition test results are used to generate asset specific end-of-life projections for core station components in accordance to FFPC's asset management process. For more detailed information about the inspection and condition testing refer to Section 5.3.1.5.b "Transformer Station Preventative Maintenance Program".

The following picture depicts FFMTS as at July 2013.



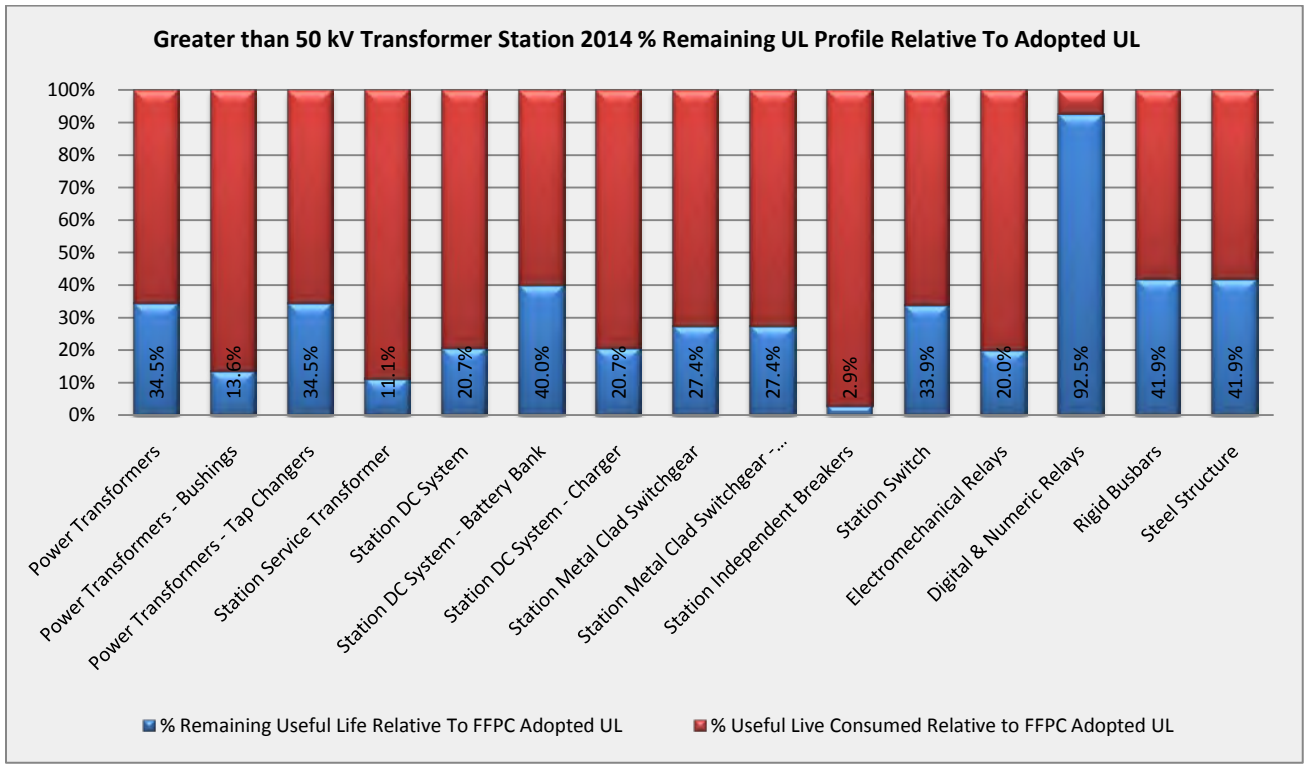
5.3.2.2.d.i. Transformer Station Lifecycle Profile, Reinvestment Needs Boundaries & Reinvestment Summary

As per the Chapter 5 Filing Requirements guide, FFPC has relied on its newly developed Asset Management Process to collect, tabulate and assess information on physical assets, current and future system operating conditions, and FFPC's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus.

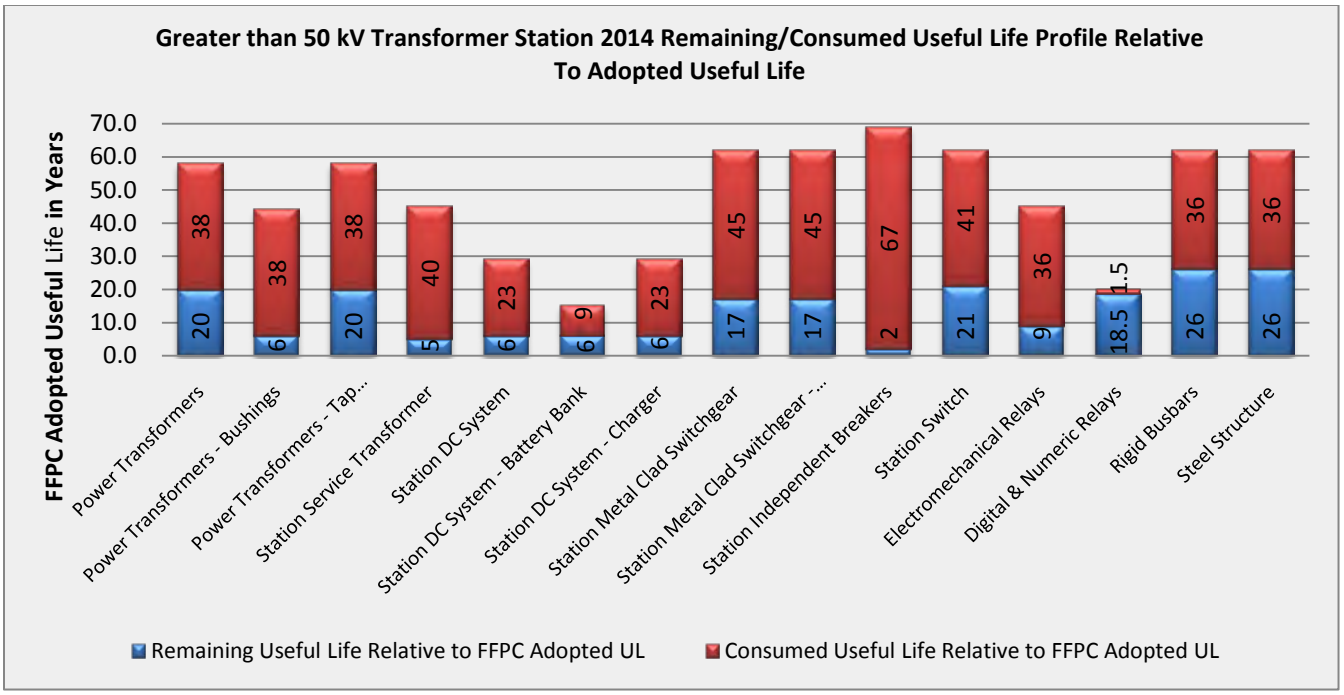
FFPC's asset management process has established a total asset replacement value of $24,379,821 for all existing assets managed, based on FFPC's replacement cost structure. Of this asset base, the replacement value of Transformer Station assets is estimated to be $4,931,185 (excluding station buildings, which are included under General Plant), which is approximately 20.2% of the total replacement value. FFPC has utilized the replacement value established by its insurance carrier for the station. Based on FFPC's adopted useful life values, the average annual reinvestment needed to keep pace with Transformer Station asset deterioration is $90,712. The overall % remaining useful life (relative to FFPC's adopted UL and replacement cost) is 32.0%. FFPC's long term objective is to retire the station upon its major components reaching 0% "Remaining UL" simultaneously. As such, lifecycle sustaining capital investments are mainly driven by the risk of assets failing prior to the retirement of the station as a whole. The nature of transformer stations is that their lifecycle costs are very sporadic, as they are made up of a small number of high value components. As such, FFPC did not allocate capital funds based on an average annual investment need, but rather according to the requirements of

individual station components, as identified by Step 4 of the asset management process. The average annual allocated capital of $41,400 is approximately 54% lower than the ideal average reinvestment need of $90,712. This will allow for intensified expenditures towards the upkeep of FFPC's aging distribution transformer fleet. The approach will ultimately help to minimize the impact of the significant increase in overall capital expenditure requirements, as FFPC transitions out of its "maintenance mode" of operation, to a "capital rebuild mode" of operation over the planning period.

The following graph illustrates the % UL Remaining profile of all Transformer Station asset categories.



The following graph illustrates the remaining and consumed years of useful life of all Transformer Station asset categories:



The following table summarizes planned capital expenditures over the 2014 to 2018 planning horizon, based on the output of Step 4 of the asset management process. Capital expenditures driven by other investment drivers, such as the Renewable Enabling Improvements, are not included in this summary. The table also illustrates the Useful Life and Reinvestment Need analysis for each asset category. Various reinvestment needs boundaries are illustrated representing various adoptions of useful service life philosophies, such as the "Kinectrics Report's" MIN UL, TUL, MAX UL as well as FFPC's adopted UL.

FFPC Asset Summary, Useful Life Assessment, Investment Boundaries and Capital Budget Allocations

		Asset Details		FFPC Assets			Kinectrics Useful Life			Useful Life Assessment					Reinvestment Needs Assessment					Capital Budget Allocation		
Parent*	#	Category| Component | Type		Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to Kinectrics TUL	% Remaining Useful Life Relative Kinectrics TUL	Remaining Useful Life Relative to FFPC Adopted UL	% Remaining Useful Life Relative To FFPC Adopted UL	Total Replacement Cost of Asset Group	Average Annual Reinvestment Need Based on Kinectrics Min UL	Average Annual Reinvestment Need Based on Kinectrics TUL	Average Annual Reinvestment Need Based on Kinectrics Max UL	Average Annual Reinvestment Need Based on FFPC Adopted UL	Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2014 to 2018)	% of Total DS Plan Capital Expenditures
TS & MS	12	Power Transformers	Overall	2	Each	38.00	30	45	60	58.0	7.0	15.6%	20.0	34.5%	$ 1,930,575	$ 64,352	$ 42,902	$ 32,176	**$ 33,286**	$ -	$ -	0.0%
			Bushing	12	Each	38.00	10	20	30	44.0	0.0	0.0%	6.0	13.6%	$ 68,351	$ 6,835	$ 3,418	$ 2,278	**$ 1,553**	$ -	$ -	0.0%
			Tap Changer	2	Each	38.00	20	30	60	58.0	0.0	0.0%	20.0	34.5%	$ 1,127,792	$ 56,390	$ 37,593	$ 18,797	**$ 19,445**	$ -	$ -	0.0%
	13	Station Service Transformer		1	Each	40.00	30	45	55	45.0	5.0	11.1%	5.0	11.1%	$ 8,544	$ 285	$ 190	$ 155	**$ 190**	$ -	$ -	0.0%
	14	Station Grounding Transformer		N/A	Each		30	40	40													
	15	Station DC System	Overall	2	Each	23.00	10	20	30	29.0	0.0	0.0%	6.0	20.7%	$ 85,439	$ 8,544	$ 4,272	$ 2,848	**$ 2,946**	$ -	$ -	0.0%
			Battery Bank	2	Each	9.00	10	15	15	15.0	6.0	40.0%	6.0	40.0%	$ 51,263	$ 5,126	$ 3,418	$ 3,418	**$ 3,418**	$ 10,000	$ 2,000	0.3%
			Charger	2	Each	23.00	20	20	30	29.0	0.0	0.0%	6.0	20.7%	$ 34,176	$ 1,709	$ 1,709	$ 1,139	**$ 1,178**	$ 22,000	$ 4,400	0.6%
	16	Station Metal Clad Switchgear	Overall	11	Each	45.00	30	40	60	62.0	0.0	0.0%	17.0	27.4%	$ 845,844	$ 28,195	$ 21,146	$ 14,097	**$ 13,643**	$ -	$ -	0.0%
			Removable Breaker	11	Each	45.00	25	40	60	62.0	0.0	0.0%	17.0	27.4%	$ 205,053	$ 8,202	$ 5,126	$ 3,418	**$ 3,307**	$ -	$ -	0.0%
	17	Station Independent Breakers		1	Each	67.00	35	45	65	69.0	0.0	0.0%	2.0	2.9%	$ 138,411	$ 3,955	$ 3,076	$ 2,129	**$ 2,006**	$ 150,000	$ 30,000	4.3%
	18	Station Switch		5	Each	41.00	30	50	60	62.0	9.0	18.0%	21.0	33.9%	$ 68,351	$ 2,278	$ 1,367	$ 1,139	**$ 1,102**	$ -	$ -	0.0%
	19	Electromechanical Relays		34	Each	36.00	25	35	50	45.0	0.0	0.0%	9.0	20.0%	$ 131,576	$ 5,263	$ 3,759	$ 2,632	**$ 2,924**	$ -	$ -	0.0%
	20	Solid State Relays		N/A	Each		10	30	45													
	21	Digital & Numeric Relays		8	Each	1.50	15	20	20	20.0	18.5	92.5%	18.5	92.5%	$ 56,390	$ 3,759	$ 2,819	$ 2,819	**$ 2,819**	$ -	$ -	0.0%
	22	Rigid Busbars		3	Each	36.00	30	55	60	62.0	19.0	34.5%	26.0	41.9%	$ 42,719	$ 1,424	$ 777	$ 712	**$ 689**	$ -	$ -	0.0%
	23	Steel Structure		1	Each	36.00	35	50	90	62.0	14.0	28.0%	26.0	41.9%	$ 136,702	$ 3,906	$ 2,734	$ 1,519	**$ 2,205**	$ 25,000	$ 5,000	0.7%
Totals															$ 4,931,185	$ 200,223	$ 134,305	$ 89,277	**$ 90,712**	$ 207,000	$ 41,400	5.9%

The following table summarizes FFPC's budgeted capital reinvestments, for each Transformer Station asset category over the 2014 to 2018 planning period. The planned reinvestments are all driven by the outputs of Step 4 of the asset management process, and as such they are allocated towards sustaining the lifecycle of existing assets. As previously mentioned, expenditures have been limited to the replacement or refurbishment of assets posing a high risk and impact of failure.

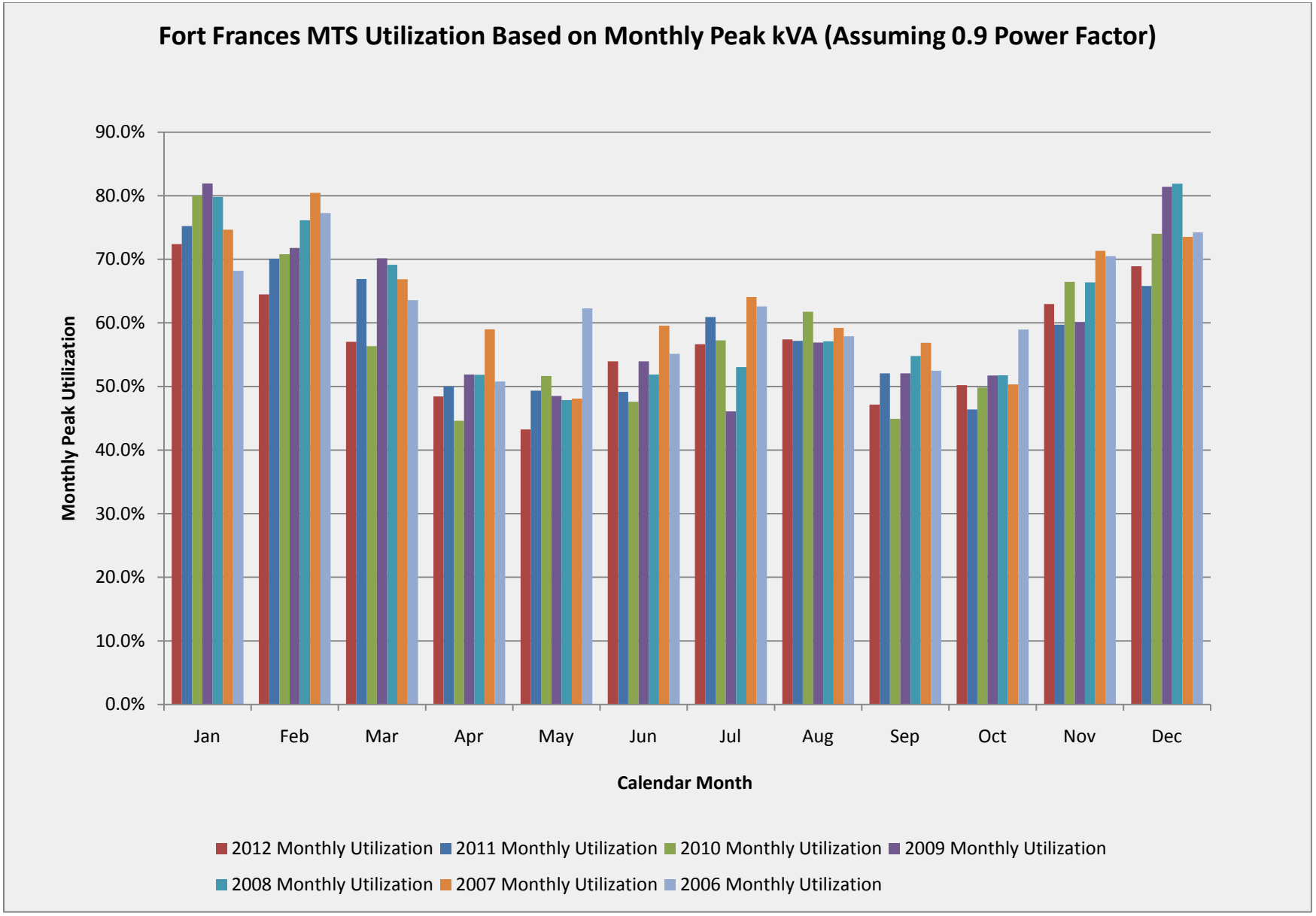
		Asset Details		Capital Budget Allocation		
Parent*	#	Category| Component | Type		Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2014 to 2018)	% of Total DS Plan Capital Expenditures
TS & MS	12	Power Transformers	Overall	$ -	$ -	0.0%
			Bushing	$ -	$ -	0.0%
			Tap Changer	$ -	$ -	0.0%
	13	Station Service Transformer		$ -	$ -	0.0%
	14	Station Grounding Transformer				
	15	Station DC System	Overall	$ -	$ -	0.0%
			Battery Bank	$ 10,000	$ 2,000	0.3%
			Charger	$ 22,000	$ 4,400	0.6%
	16	Station Metal Clad Switchgear	Overall	$ -	$ -	0.0%
			Removable Breaker	$ -	$ -	0.0%
	17	Station Independent Breakers		$ 150,000	$ 30,000	4.3%
	18	Station Switch		$ -	$ -	0.0%
	19	Electromechanical Relays		$ -	$ -	0.0%
	20	Solid State Relays				
	21	Digital & Numeric Relays		$ -	$ -	0.0%
	22	Rigid Busbars		$ -	$ -	0.0%
	23	Steel Structure		$ 25,000	$ 5,000	0.7%
Totals				$ 207,000	$ 41,400	5.9%

5.3.2.2.d.ii. Transformer Station Capacity & Utilization

Fort Frances MTS was designed to be a transformer station servicing strictly municipal load. As such, the station in its current state is not able to accommodate reverse power flow at any level. The station is currently designed for a maximum station load of 25 MVA. This limit is set by the rating of the two power transformers, which are both rated at 25 MVA. It is again important to note that the station was designed with transformer redundancy, such that either transformer is able to supply power to the entire distribution network in the event of a transformer failure or outage. As such, the station maximum capacity is set to 25 MVA as opposed to 50 MVA. As a winter peaking utility, the colder the temperature, the higher the consumer demands for electricity. The station capacity is suitable for FFPC's customer load and it offers room for future load growth. Transformer station capacity constraints are therefore not identified as being an investment driver over the 2014 to 2018 planning

horizon. The following table and subsequent graph illustrate the monthly kW demand peaks and the corresponding percent utilization based on a power factor of 0.9 and a station capacity of 25 MVA.

Fort Frances MTS Monthly Utilization Based on Monthly kW Peak (Converted to kVA assuming 0.9 Power Factor)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2012 Monthly Peak kW	16,288	14,508	12,826	10,900	9,733	12,137	12,749	12,915	10,607	11,296	14,169	15,506
2012 Monthly Utilization	72.4%	64.5%	57.0%	48.4%	43.3%	53.9%	56.7%	57.4%	47.1%	50.2%	63.0%	68.9%
2011 Monthly Peak kW	16,925	15,769	15,052	11,251	11,102	11,055	13,707	12,868	11,718	10,441	13,431	14,803
2011 Monthly Utilization	75.2%	70.1%	66.9%	50.0%	49.3%	49.1%	60.9%	57.2%	52.1%	46.4%	59.7%	65.8%
2010 Monthly Peak kW	18,000	15,927	12,681	10,038	11,618	10,708	12,881	13,893	10,106	11,211	14,954	16,653
2010 Monthly Utilization	80.0%	70.8%	56.4%	44.6%	51.6%	47.6%	57.2%	61.7%	44.9%	49.8%	66.5%	74.0%
2009 Monthly Peak kW	18,432	16,147	15,787	11,672	10,916	12,143	10,367	12,802	11,716	11,640	13,526	18,314
2009 Monthly Utilization	81.9%	71.8%	70.2%	51.9%	48.5%	54.0%	46.1%	56.9%	52.1%	51.7%	60.1%	81.4%
2008 Monthly Peak kW	17,957	17,131	15,553	11,667	10,772	11,671	11,938	12,843	12,329	11,643	14,935	18,421
2008 Monthly Utilization	79.8%	76.1%	69.1%	51.9%	47.9%	51.9%	53.1%	57.1%	54.8%	51.7%	66.4%	81.9%
2007 Monthly Peak kW	16,798	18,097	15,045	13,274	10,818	13,402	14,414	13,321	12,795	11,321	16,049	16,539
2007 Monthly Utilization	74.7%	80.4%	66.9%	59.0%	48.1%	59.6%	64.1%	59.2%	56.9%	50.3%	71.3%	73.5%
2006 Monthly Peak kW	15,338	17,382	14,304	11,424	14,017	12,404	14,085	13,028	11,808	13,268	15,859	16,707
2006 Monthly Utilization	68.2%	77.3%	63.6%	50.8%	62.3%	55.1%	62.6%	57.9%	52.5%	59.0%	70.5%	74.3%


Fort Frances MTS Utilization Based on Monthly Peak kVA (Assuming 0.9 Power Factor)
Monthly Peak Utilization
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Calendar Month
2012 Monthly Utilization
2011 Monthly Utilization
2010 Monthly Utilization
2009 Monthly Utilization
2008 Monthly Utilization
2007 Monthly Utilization
2006 Monthly Utilization

The following table summarizes the overall system capacity as established from power transformer ratings, as well as feeder ampacity limitations:

Fort Frances MTS & Feeder Capacity					
Transformer Rating (ONAF) In MVA	**FFMTS Feeder**	**Voltage (kV)**	**OH Primary Circuit Length (km)**	**UG Primary Circuit Length (km)**	**Total Primary Circuit Length (km)**
T1 - 20/25 MVA	West Feeder (A): 10 MW	7.2/12.47	19.49	4.42	23.91
	Mowat Feeder (D): 10 MW	7.2/12.47	5.42	0.45	5.87
	East Feeder (G): 10 MW	7.2/12.47	13.04	2.20	15.23
Transformer T1 Circuits Subtotal			**37.94**	**7.07**	**45.01**
T2 - 20/25 MVA	Third Street Feeder (B): 10 MW	7.2/12.47	9.50	0.52	10.03
	Victoria Feeder (E): 10 MW	7.2/12.47	7.78	1.00	8.78
	Crowe Feeder (F): 10 MW	7.2/12.47	10.57	2.02	12.59
Transformer T2 Circuit Subtotal			**27.86**	**3.55**	**31.40**
System Total			**65.80**	**10.61**	**76.41**
Note: Fort Frances MTS Load Capacity = 25 MVA under normal fully redundant operating mode					

5.3.2.2.d.iii. Transformer Station Asset Age Profile

According to Maximum Useful Life projections, the station is expected to have an end-of-life date of 2034, as many of the major components will be at their maximum useful life at that time. The following table illustrates the quantity of station components, their age, adjusted end-of-life projections based on FFPC's asset management process, as well as the replacement cost for components that demand replacements during the 2014 to 2018 rate horizon. Components requiring replacement over the rate horizon have been highlighted in red for ease of reference.

Transformer Station "Fort Frances MTS" Asset Age Profile & Adjusted End-of-Life Profile														
		Asset Details		FFPC Assets			Kinectrics Useful Life			Age Assessment		Adjusted End-of-Life	Replacement Cost	
Parent*	#	Category| Component | Type		Count	Year of Manufacture	Age (Years) Relative to 2014	MIN UL	TUL	MAX UL	TUL - Age	Max UL - Age	Adjusted End-of-Life Based on FFPC Asset Management Process	Replacement Cost	
TS & MS	12	Power Transformers (T1)	Overall	1	1974	40	30	45	60	***5***	***20***	***2034***		
			Bushing	6	1974	40	10	20	30	***-20***	***-10***	***2020***		
			Tap Changer	1	1974	40	20	30	60	***-10***	***20***	***2034***		
		Power Transformers (T2)	Overall	1	1978	36	30	45	60	***9***	***24***	***2034***		
			Bushing	6	1978	36	10	20	30	***-16***	***-6***	***2020***		
			Tap Changer	1	1978	36	20	30	60	***-6***	***24***	***2034***		
	13	Station Service Transformer		1	1974	40	30	45	55	***5***	***15***	***2019***		
	15	Station DC System (T1)	Overall	1	1990	24	10	20	30	***-4***	***6***	***2020***		
			Battery Bank	1	Various	2 to 15 Years	10	15	15	***Various***		***2014-2018***	$	1,000
			Charger	1	1990	24	20	20	30	***-4***	***6***	***2018***	$	22,000
		Station DC System (T2)	Overall	1	1992	22	10	20	30	***-2***	***8***	***2022***		
			Battery Bank	1	Various	2 to 15 Years	10	15	15	***Various***		***2014-2018***	$	1,000
			Charger	1	1992	22	20	20	30	***-2***	***8***	***2022***		
	16	Station Metal Clad Switchgear (T1)	Overall	5	1965	49	30	40	60	***-9***	***11***	***2034***		
			Removable Breaker	5	1965	49	25	40	60	***-9***	***11***	***2034***		
		Station Metal Clad Switchgear (T2)	Overall	6	1973	36	30	40	60	***-1***	***19***	***2034***		
			Removable Breaker	6	1973	36	25	40	60	***-1***	***19***	***2034***		
	17	Station Independent Breakers		1	1947	67	35	45	65	***-22***	***-2***	***2018***	$	150,000
	18	Station Switch		5	1973	41	30	50	60	***9***	***19***	***2034***		
	19	Electromechanical Relays		34	1978	36	25	35	50	***-1***	***14***	***2014-2018***	*See "Renewable Enabling Improvements"*	
	20	Solid State Relays		N/A	1978	N/A	10	30	45	***N/A***	***N/A***	***N/A***		
	21	Digital & Numeric Relays		4	2012	2	15	20	20	***18***	***18***	***2034***		
		Digital & Numeric Relays		4	2013	1	15	20	20	***19***	***19***	***2034***		
	22	Rigid Busbars		3	1978	36	30	55	60	***19***	***24***	***2034***		
	23	Steel Structure		1	1978	36	35	50	90	***14***	***54***	***2034***		

5.3.2.2.d.iii.1 Power Transformers:

FFPC performs annual inspections and conducts annual oil testing (condition analysis) to determine the health of the transformers. Both power transformers are found to be in good condition relative to their age. Given current operating conditions and maintenance practices, both units are expected to achieve their maximum useful life of 60 years. The adjusted end-of-life dates have been set to 2034, at which time the station as a whole is expected to reach its end-of-life. FFPC does not plan on incurring any significant expenses in this category for years 2014 to 2018.

5.3.2.2.d.iii.2 Power Transformer Bushings:

The bushings of both station transformers have exceeded the maximum useful life established in the Kinectrics report. The bushings are also tested annually and are found to be in good health with no sign of physical deterioration. Although the bushings have exceeded their maximum useful life, FFPC does not plan on replacing them over the rate horizon, given the favourable condition test results, as well as based on expert advice stating that it is not necessary at this time. FFPC will continue to closely monitor the health of all bushings and look for signs of deterioration. FFPC does not plan on incurring any significant expenses in this category for years 2014 to 2018.

5.3.2.2.d.iii.3 Power Transformer Tap Changers:

The tap changers on both power transformers have had extensive maintenance work performed on them since their original install. Incoming supply voltage fluctuations were found to typically be short in duration, and often did not warrant an adjustment to be made. As such, FFPC recently detuned the tap changers which greatly reduced the number of operations required, thereby greatly extending service life. Overall, the tap changers are found to be in good condition relative to their age, and recent condition test results have not identified any health issues. The tap changers are also anticipated to reach their maximum useful life without failure, based on current operating conditions and maintenance practices. As such, the tap changers have also been assigned an adjusted end-of-life date of 2034 in alignment with the end-of-life of the station as a whole. FFPC does not plan on incurring any significant expenses in this category between the years 2014 to 2018.

5.3.2.2.d.iii.4 Station Service Transformer:

The station service transformer is also original to the construction of the transformer station. Condition test results have not found any signs of premature failure, and as such, the transformer is expected to achieve its typical-useful-life of 45 years. Due to its importance in regards to station functionality, FFPC plans to replace it in 2019 when it has reached the end of its typical useful service life. As such, the adjusted end-of-life has been set to 2019, and FFPC does not plan on incurring any significant expenses in this category for years 2014 to 2018.

5.3.2.2.d.iii.5 Station DC System:

The transformer station has two separate DC systems installed to supply power to key station protection components, as well as to emergency lights. Both systems were replaced within a two year window, and as such, neither system is original to the transformer station. The systems are inspected on a monthly basis to ensure their proper operation. FFPC also conducts annual condition tests on each battery cell to assess whether replacement in needed. The inspection and condition tests have found both systems to be in good overall working condition relative to their age. Both systems have surpassed their TUL. Due to the criticality of these systems, FFPC has assigned 2018 and 2022 respectively as adjusted end-of-life service life dates. As such, FFPC plans to replace the T1 DC system in 2018 with an estimated replacement cost of $22,000. FFPC also plans to continue with its annual replacement of deteriorated battery cells throughout the period 2014 to 2018, and has budgeted $2,000 per year accordingly.

5.3.2.2.d.iii.6 Station Metal Clad Switchgear:

The transformer station has two main metal clad switchgear lineups, each containing five breakers cells, as well as one additional bus-tie breaker that connects the two lineups if required. Transformer T1's switchgear was installed in 1972, however, the switchgear was purchased slightly used and as such, it was manufactured in 1965. Transformer T2's switchgear was purchased new and it was manufactured in 1973. Under FFPC's preventative maintenance program, all breakers are thoroughly inspected and condition tested on a three year cycle. Any maintenance issues identified are also addressed at that time. The latest condition assessments and inspections found all breakers and switchgear to be in good overall condition, relative to their age. The breakers have surpassed their TUL; however, given their current operating condition and environment, FFPC expects them to achieve their maximum useful service life of 60 years. Parts availability is a known issue and as such, an unexpected breaker failure could result in a breaker replacement, rather than a refurbishment. FFPC has assigned adjusted end-of-life dates of 2034, to align with the overall station end of service life. In the short term, for period 2014 to 2018, FFPC does not plan on incurring any significant expense in this category.

5.3.2.2.d.iii.7 Station Independent Breaker:

FFPC performs annual inspections and oil condition testing on its station independent breaker that protects the transformer station as a whole. The oil filled circuit breaker (OCB) has surpassed its maximum useful life of 65 years, as it was manufactured in 1947. Although the breaker has exceeded its MUL of 65 years, recent inspections and condition test results indicate that the unit is in good working condition relative to its age. Sourcing replacement parts for the unit is also a known issue. Siemens Canada has advised FFPC that the unit should be replaced by 2018, and as such FFPC has assigned an adjusted end-of-life date of 2018. FFPC plans to replace the unit in 2018 at an estimated cost of $150,000. This replacement of this unit is a significant cost driver for the 2014 to 2018 rate horizon. The following picture depicts the oil filled circuit breaker (three single phase units).



5.3.2.2.d.iii.8 Station Switches:

Fort Frances MTS contains five sets of three phase switches, which allow for the isolation of various components including Transformer T1, Transformer T2, as well as the Oil filled Circuit breakers that protect the station. FFPC has utilized planned loss of supply opportunities to inspect the units, as well as to perform condition tests. FFPC also used these opportunities to perform maintenance work including testing insulators and realigning switch linkages All five units are found to be in good working condition relative to their age, with no signs of excess deterioration. Given current operating conditions and continued maintenance practices, FFPC expects the units to surpass their maximum useful service life of 60 years. FFPC has assigned an adjusted end-of-life date of 2034, to align with the end of useful service life with that of the station as a whole. FFPC does not plan on incurring any significant expenses in this category for years 2014 to 2018.

5.3.2.2.d.iii.9 Electromechanical Relays:

During the construction of Fort Frances MTS, protection technology offered single function electromechanical relays. As such, the transformer station was equipment entirely with single function electromechanical relays. In 2012, FFPC began to convert the first lineup of single function electromechanical relays with modern processor based multifunction relays, in order to accommodate the connection of renewable generation. Refer to Section 5.4.3 for details regarding system limitations and planned Renewable Enabling Improvements to accommodate the connection of renewable generation. The electromechanical relays that have not yet been converted have a UL of 35 years. Under FFPC's preventative maintenance program all relays are inspected, calibrated and condition tested on a three year rotation. The most recent condition tests found all relays to be in good working condition relative to their age. The relays are expected to achieve their maximum useful life of 50 years under current operating conditions and maintenance practices. As such, the adjusted end-of-life values of 2023 were assigned; however, they will be revised upon approval of FFPC's planned Renewable

Enabling Improvements, which would deem the devices obsolete. As discussed under the Renewable Enabling Improvements section, modern day relays will allow for: reliability monitoring (statistics) of individual feeders, reverse power flow, automatic logging and time-stamping of events or data, remote annunciation of incidents or failures, broadcasting of operating data and conditions to FFPC and other regional stakeholders.

5.3.2.2.d.iii.10 Digital & Numeric Relays:

In 2012, FFPC installed the first digital multifunction protection relays (same a "Digital & Numeric Relays") in place of single function electromechanical relays for all breakers fed from Transformer T1. In 2013, FFPC replaced the electromechanical relays on all breakers that are fed from Transformer T2. As previously discussed, the driver for these replacements was to accommodate renewable generation rather than the equipment having reached the end of its useful service life. FFPC will continue with its preventative maintenance practices of inspecting and performing condition analysis of these relays on a three year rotation. FFPC has adopted the Kinectrics TUL for Digital & Numeric relays of 20 years. FFPC has set the adjusted useful life values accordingly, which are 2032 and 2033 respectively. FFPC will assess whether or not the relays are on track for a 20 year useful life in future iterations of condition testing. FFPC plans on continuing with the upgrades from electromechanical relays to digital multifunction protection relays (Digital & Numeric) under the REG initiative. The following picture illustrates the replacement of 1970s analog gauges and single function electromechanical relays with a single multifunction relay. FFPC is planning to continue to deploying "Schweitzer Engineering Laboratories (SEL) 751" relays.



Figure 2: West Feeder Original Single Function Electromechanical Relays



Figure 3: West Feeder Replacement Multifunction Protection Relay

5.3.2.2.d.iii.11 Rigid Busbars:

Fort France MTS contains three sections of rigid bus bars. The busbars are inspected annually as part of FFPC's preventative maintenance program. According to inspection and condition tests, the busbars are found to be in good condition relative to their age. FFPC expects that the units will all achieve their maximum useful life of sixty (60) years. As such, their adjusted end-of-life dates have been set to align with the overall end-of-useful life of the transformer station in 2034. FFPC does not expect to incur any significant expenses in this category over the period 2014 to 2018.

5.3.2.2.d.iii.12 Steel Structures:

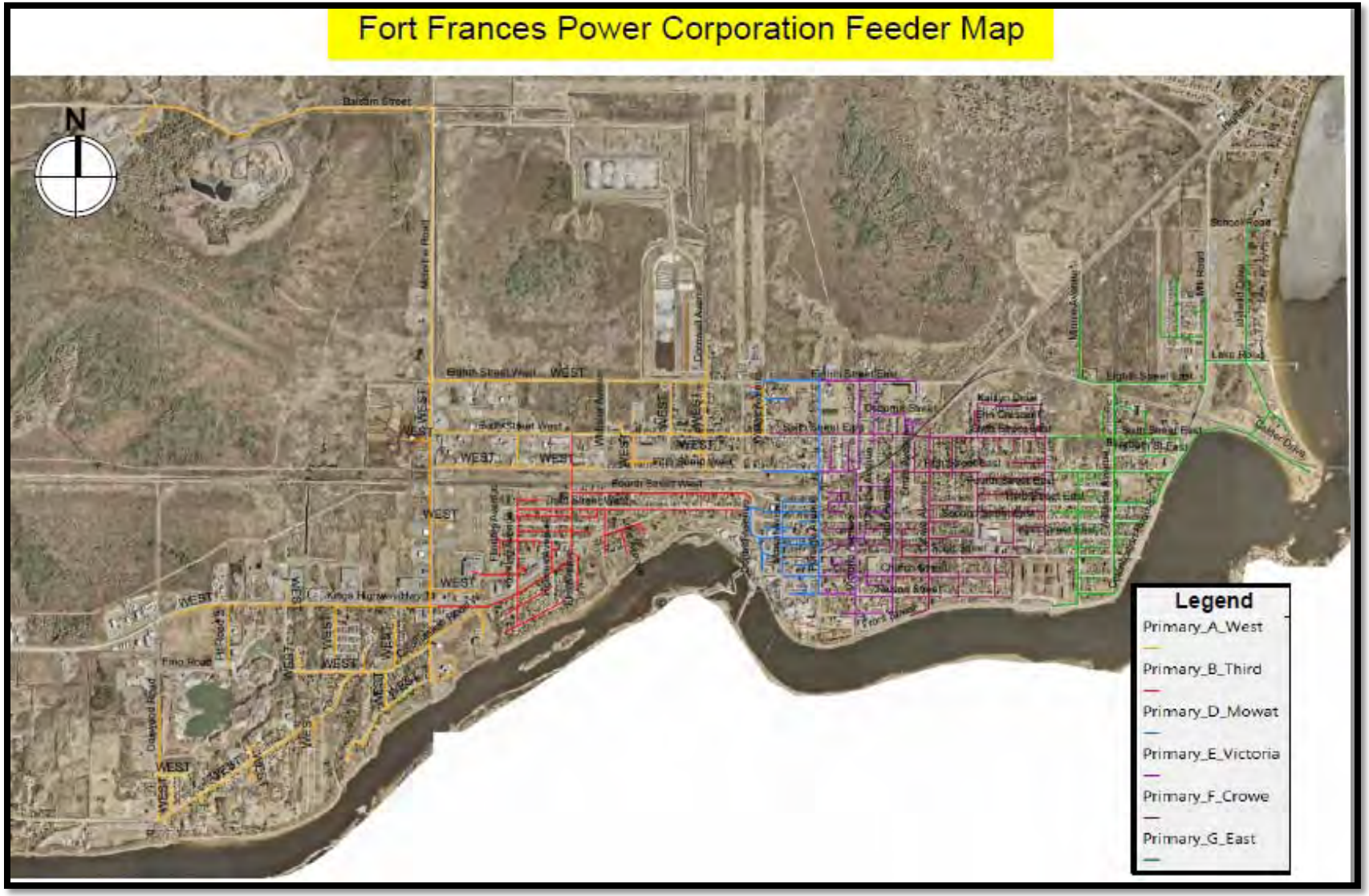
Fort Frances MTS has one sky structure in the Steel Structure category. The structure was erected around 1978 and it is found to be in good condition relative to its age. Inspection and condition testing results have not identified any excessive deterioration. Under current operating conditions and maintenance practices, FFPC expects that the structure will surpass its TUL of fifty (50) years, as per the "Kinectrics Report". FFPC has set its adjusted end-of-life to 2034, to align with the end of useful life for the station as a whole. FFPC does not expect to incur any significant expenses in this category over the period 2014 to 2018. The following picture shows the steel structure being erected.



5.3.2.2.e. Overhead Distribution System Assets

FFPC operates a single voltage 7.2/12.47 kV electrical distribution system that spans throughout the community of the Town of Fort Frances. As previously mention, FFPC performed a complete system rebuild and voltage conversion from the mid-1970s to the mid-1980s.

FFPC utilizes six feeders that propagate from FFMTS throughout the Town of Fort Frances. The feeders do not extend beyond FFPC's licensed distribution service territory. The following map illustrates how FFPC's distribution feeders propagate throughout Fort Frances.

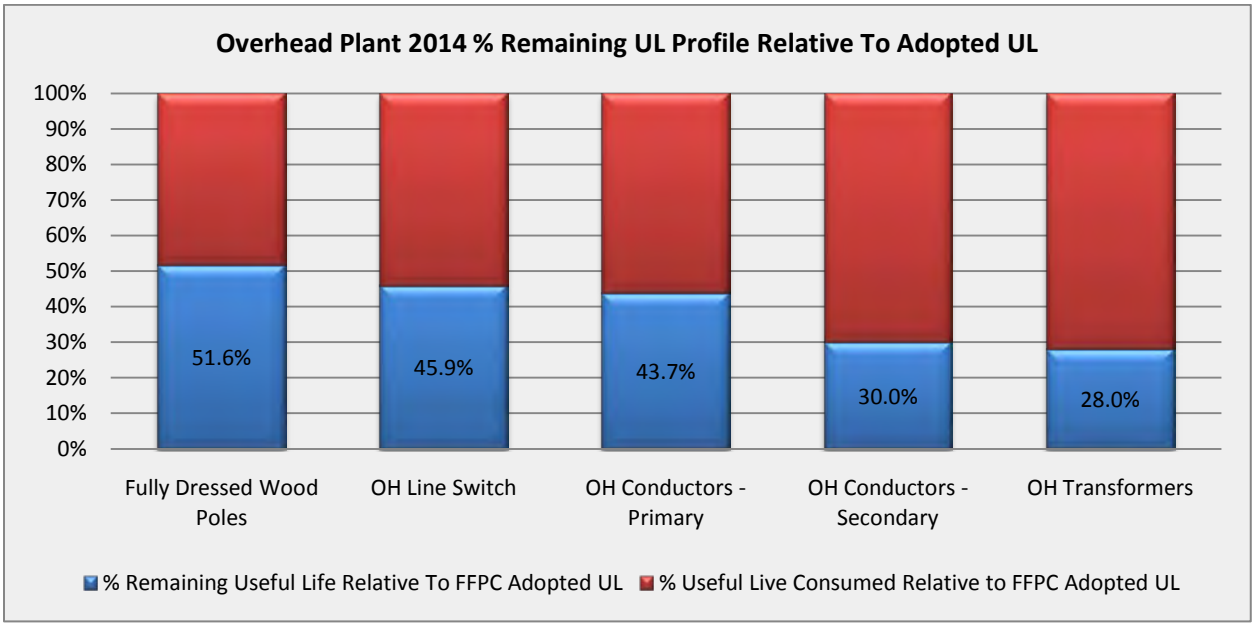

Fort Frances Power Corporation Feeder Map
N
Legend
Primary_A_West
Primary_B_Third
Primary_D_Mowat
Primary_E_Victoria
Primary_F_Crowe
Primary_G_East

5.3.2.2.e.i. Overhead Plant Lifecycle Profile, Reinvestment Needs Boundaries & Reinvestment Summary

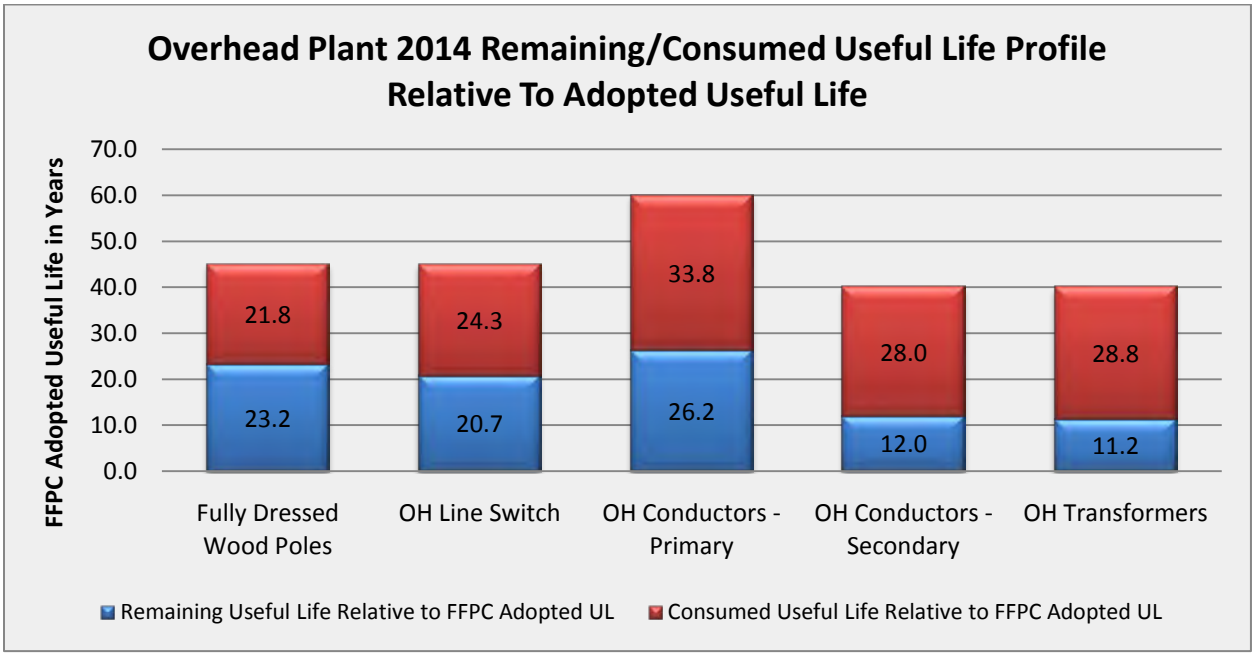
As per the Chapter 5 Filing Requirements guide, FFPC has relied on its newly developed Asset Management Process to collect, tabulate and assess information on physical assets, current and future system operating conditions, and FFPC's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus.

FFPC's asset management process has established a total asset replacement value of $24,379,821 for all existing assets managed, based on FFPC's replacement cost structure. Of this asset base, the replacement value of Overhead Plant assets is estimated to be $10,566,447 which is approximately 43.3% of the total replacement value. Based on FFPC's adopted useful life values, the average annual reinvestment needed to keep pace with Overhead Plant asset deterioration is $241,566. The overall % remaining useful life (relative to FFPC's adopted UL and replacement cost) is 42.7%. FFPC's long term objective is to maintain a 50% "Remaining UL" profile where possible, to smooth long term spending requirements. As such, FFPC has an optimal capital reinvestment budget allocation of $241,566 to sustain the lifecycle of Overhead Plant assets. FFPC has allocated a total of $1,253,756 towards sustaining the lifecycle of Overhead Plant, which equates to an average annual reinvestment of $250,751. This closely aligned with the ideal average annual reinvestment need and accomplishes FFPC's objective to keep pace with the rate of deterioration.

The following graph illustrates the % UL Remaining profile of all Overhead Plant asset categories.



The following graph illustrates the remaining and consumed years of all Overhead Plant asset categories:



The following tables summarize planned capital expenditures over the 2014 to 2018 planning horizon, based on assets that were identified to be at the end of their useful service life, as per outputs of Step 4 of the asset management process. Capital expenditures driven by other investment drivers such as the elimination of LTLT's, Customer Preference or Renewable Enabling Improvements are not included in

this summary. The table also illustrates the Useful Life and Reinvestment Need analysis for each asset category. Various reinvestment needs boundaries are illustrated representing various adoptions of useful service life philosophies, such as the “Kinectrics Report’s” MIN UL, TUL, MAX UL as well as FFPC’S adopted UL.

FFPC Asset Summary, Useful Life Assessment, Investment Boundaries and Capital Budget Allocations																						
		Asset Details			FFPC Assets			Kinectrics Useful Life			Useful Life Assessment					Reinvestment Needs Assessment					Capital Budget Allocation		
Parent*	#	Category| Component | Type			Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to Kinectrics TUL	% Remaining Useful Life Relative Kinectrics TUL	Remaining Useful Life Relative to FFPC Adopted UL	% Remaining Useful Life Relative To FFPC Adopted UL	Total Replacement Cost of Asset Group	Average Annual Reinvestment Need Based on Kinectrics Min UL	Average Annual Reinvestment Need Based on Kinectrics TUL	Average Annual Reinvestment Need Based on Kinectrics Max UL	Average Annual Reinvestment Need Based on FFPC Adopted UL	Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2014 to 2018)	% of Total DS Plan Capital Expenditures
OH	1	Fully Dressed Wood Poles	Overall		1776	Each	21.79	35	45	75	45.0	23.2	51.6%	23.2	51.6%	$ 5,850,761	$ 167,165	$ 130,017	$ 78,010	**$ 130,017**	$ 679,638	$ 135,928	19.3%
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	2	Fully Dressed Concrete Poles	Overall		N/A			50	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	3	Fully Dressed Steel Poles	Overall		N/A			60	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	4	OH Line Switch (Expressed as sets of 3 Phase Switches)			35	Each	24.34	30	45	55	45.0	20.7	45.9%	20.7	45.9%	$ 254,409	$ 8,480	$ 5,654	$ 4,626	**$ 5,654**	$ 32,500	$ 6,500	0.9%
	5	OH Line Switch Motor			N/A			15	25	25													
	6	OH Line Switch RTU			N/A			15	20	20													
	7	OH Integral Switches			N/A			35	45	60													
	8	OH Conductors	Primary Conductor		224.2	km	33.77	50	60	75	60.0	26.2	43.7%	26.2	43.7%	$ 676,409	$ 13,528	$ 11,273	$ 9,019	**$ 11,273**	$ -	$ -	0.0%
			Secondary Conductor		114.8	km	28.00	25	35	40	40.0	7.0	20.0%	12.0	30.0%	$ 1,033,603	$ 41,344	$ 29,532	$ 25,840	**$ 25,840**	$ 50,000	$ 10,000	1.4%
	9	OH Transformers			629	Each	28.79	30	40	60	40.0	11.2	28.0%	11.2	28.0%	$ 2,751,265	$ 91,709	$ 68,782	$ 45,854	**$ 68,782**	$ 491,617	$ 98,323	14.0%
	10	OH Shunt Capacitor Banks			N/A			25	30	40													
	11	Reclosers			N/A			25	40	55													
Totals																$ 10,566,447	$ 322,226	$ 245,257	$ 163,349	**$ 241,566**	$ 1,253,756	$ 250,751	35.6%

The following table summarizes FFPC's budgeted capital reinvestments, for each Overhead Plant asset category over the 2014 to 2018 planning period. The planned reinvestments are all driven by the outputs of Step 4 of the asset management process, and as such they are allocated towards sustaining the lifecycle of existing assets.

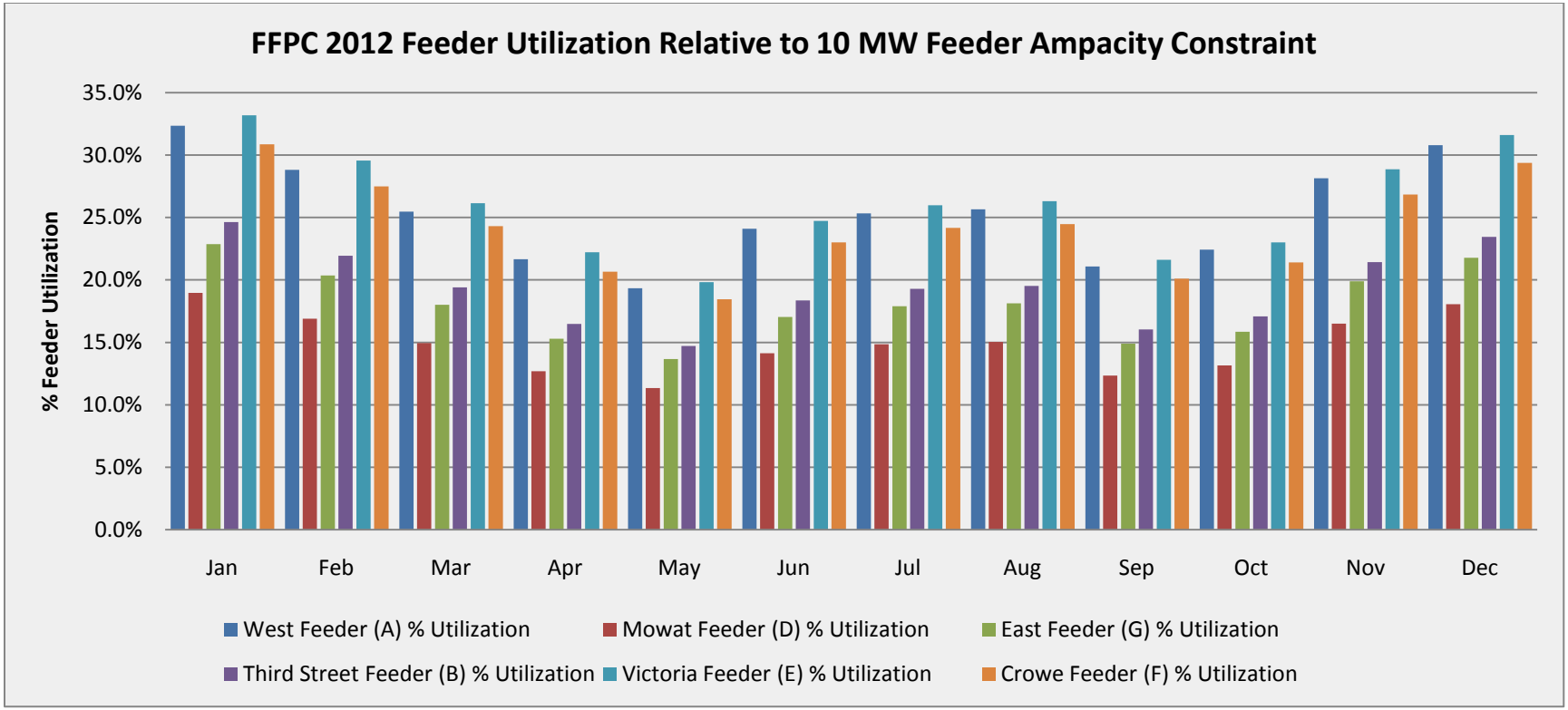
Asset Details					Capital Budget Allocation		
Parent*	#	Category| Component | Type			Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2014 to 2018)	% of Total DS Plan Capital Expenditures
OH	1	Fully Dressed Wood Poles	Overall		$ 679,638	$ 135,928	19.3%
			Cross Arm	Wood			
				Steel			
	2	Fully Dressed Concrete Poles	Overall				
			Cross Arm	Wood			
				Steel			
	3	Fully Dressed Steel Poles	Overall				
			Cross Arm	Wood			
				Steel			
	4	OH Line Switch			$ 32,500	$ 6,500	0.9%
	5	OH Line Switch Motor					
	6	OH Line Switch RTU					
	7	OH Integral Switches					
	8	OH Conductors	Primary Conductor		$ -	$ -	0.0%
			Secondary Conductor		$ 50,000	$ 10,000	1.4%
	9	OH Transformers			$ 491,617	$ 98,323	14.0%
	10	OH Shunt Capacitor Banks					
	11	Reclosers					
Totals					$ 1,253,756	$ 250,751	35.6%

5.3.2.2.e.ii. Overhead Distribution System Capacity & Utilization

At the time of preparing this submission, FFPC had to rely on spot testing for determining how FFPC's load from its transformer station is distributed among its six feeders, as synchronized individual feeder metering data is not yet available. The total station load was determined using 2012 monthly wholesale metering data. FFPC's overhead distribution system has an overall ampacity constraint of 10 MW on each feeder, based on conductor size limitations. This constraint is much higher than other underlying constraints, and as such FFPC does not expect to encounter feeder capacity constraints, given the current load profile of its customer base. FFPC also does not anticipate significant customer growth, but rather is expecting a slight decrease in the number of customers served. As such, overhead distribution system capacity constraints are not identified as investment drivers for the period 2014 to 2018.

The following table and graph illustrates FFPC's estimated maximum monthly feeder loading and corresponding feeder utilization based on the 10 MW constraints. The feeder load distribution is based on the results of spot testing performed in the fall of 2012. The following graph illustrates 2012 feeder utilization by calendar month.

FFPC 2012 Monthly Feeder Utilization Based on % of 10 MW Ampacity Constraint												
FFMTS Feeder	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
West Feeder (A) Max kW Load	3235	2882	2548	2165	1933	2411	2532	2565	2107	2244	2814	3080
West Feeder (A) % Utilization	32.4%	28.8%	25.5%	21.7%	19.3%	24.1%	25.3%	25.7%	21.1%	22.4%	28.1%	30.8%
Mowat Feeder (D) Max kW Load	1897	1689	1493	1269	1133	1413	1484	1504	1235	1315	1650	1805
Mowat Feeder (D) % Utilization	19.0%	16.9%	14.9%	12.7%	11.3%	14.1%	14.8%	15.0%	12.4%	13.2%	16.5%	18.1%
East Feeder (G) Max kW Load	2287	2037	1801	1530	1367	1704	1790	1813	1489	1586	1989	2177
East Feeder (G) % Utilization	22.9%	20.4%	18.0%	15.3%	13.7%	17.0%	17.9%	18.1%	14.9%	15.9%	19.9%	21.8%
Third Street Feeder (B) Max kW Load	2464	2194	1940	1649	1472	1836	1928	1953	1604	1709	2143	2345
Third Street Feeder (B) % Utilization	24.6%	21.9%	19.4%	16.5%	14.7%	18.4%	19.3%	19.5%	16.0%	17.1%	21.4%	23.5%
Victoria Feeder (E) Max kW Load	3319	2956	2614	2221	1983	2473	2598	2632	2161	2302	2887	3160
Victoria Feeder (E) % Utilization	33.2%	29.6%	26.1%	22.2%	19.8%	24.7%	26.0%	26.3%	21.6%	23.0%	28.9%	31.6%
Crowe Feeder (F) Max kW Load	3087	2749	2430	2066	1844	2300	2416	2447	2010	2141	2685	2938
Crowe Feeder (F) % Utilization	30.9%	27.5%	24.3%	20.7%	18.4%	23.0%	24.2%	24.5%	20.1%	21.4%	26.8%	29.4%


FFPC 2012 Feeder Utilization Relative to 10 MW Feeder Ampacity Constraint
% Feeder Utilization
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
West Feeder (A) % Utilization
Mowat Feeder (D) % Utilization
East Feeder (G) % Utilization
Third Street Feeder (B) % Utilization
Victoria Feeder (E) % Utilization
Crowe Feeder (F) % Utilization

5.3.2.2.e.iii. Overhead Distribution System Asset Classifications

FFPC has grouped its overhead distribution assets according to the classifications contained in the "Kinectrics Report". FFPC does not have any assets in the following categories, and as such they have been omitted: Fully Dressed Concrete Poles; Fully Dressed Steel Poles; Line Switch Motors; Line Switch RTU; Overhead Shunt Capacitor Banks; and Reclosers.

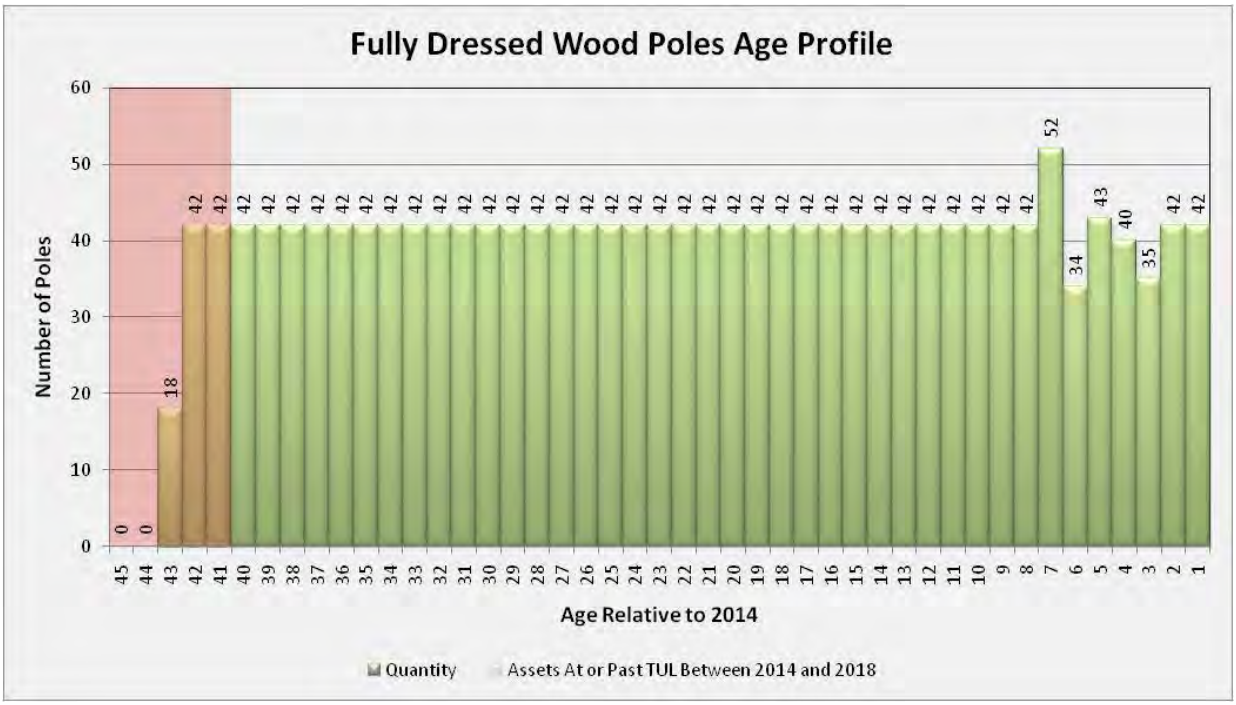
5.3.2.2.e.iii.1 Fully Dressed Wood Poles

All of FFPC's overhead pole lines are constructed using treated wood poles. FFPC has adopted a UL of 45 years for wood poles, as per the "Kinetrics Report." It is important to note that FFPC has experienced premature pole failures over the course of history due to manufacturing flaws in the wood treatment process. FFPC currently owns 1776 wood poles and would have to replace on average 39.4 poles every year to keep pace with the lifecycle of wood poles. FFPC's maintenance inspection and condition testing program is currently identifying slightly more than 40 poles per year, which are deemed to be at the end of their useful service life due to excessive deterioration. Given the history of poor wood treatment and recent condition testing results, FFPC is planning to pace wood pole replacements at 42 planed replacements per year.

5.3.2.2.e.iii.1.a Fully Dressed Wood Poles Age Profile Relative to TUL

The following table and graph illustrate the age profile of FFPC's wood poles with respect to a TUL of 45 years as per the "Kinectrics Report". Note that FFPC does not have any poles in service which are older than 1970, due to entire system voltage conversion and rebuild that began then.

Fully Dressed Wood Poles Age Profile (Relative to 2014 - Based on July 2013 Data)				
In Service Year	**Age**	**End-of-Life (Based on 45 Year TUL)**	**Quantity**	**Poles Age Could be Confirmed**
1969	**45**	**2014**	**0**	
1970	**44**	**2015**	**0**	
1971	**43**	**2016**	**18**	
1972	**42**	**2017**	**42**	
1973	**41**	**2018**	**42**	
1974	40	2019	42	
1975	39	2020	42	3
1976	38	2021	42	
1977	37	2022	42	
1978	36	2023	42	1
1979	35	2024	42	1
1980	34	2025	42	6
1981	33	2026	42	
1982	32	2027	42	
1983	31	2028	42	2
1984	30	2029	42	1
1985	29	2030	42	
1986	28	2031	42	
1987	27	2032	42	32
1988	26	2033	42	12
1989	25	2034	42	34
1990	24	2035	42	14
1991	23	2036	42	36
1992	22	2037	42	13
1993	21	2038	42	26
1994	20	2039	42	21
1995	19	2040	42	6
1996	18	2041	42	21
1997	17	2042	42	7
1998	16	2043	42	40
1999	15	2044	42	19
2000	14	2045	42	4
2001	13	2046	42	52
2002	12	2047	42	62
2003	11	2048	42	1
2004	10	2049	42	
2005	9	2050	42	5
2006	8	2051	42	11
2007	7	2052	52	52
2008	6	2053	34	34
2009	5	2054	43	43
2010	4	2055	40	40
2011	3	2056	35	35
2012	2	2057	42	42
2013	1	2058	42	42
Total			**1776**	**715**
Note: Years 8 through 45 are estimated due to illegible manufacturer date stamps				



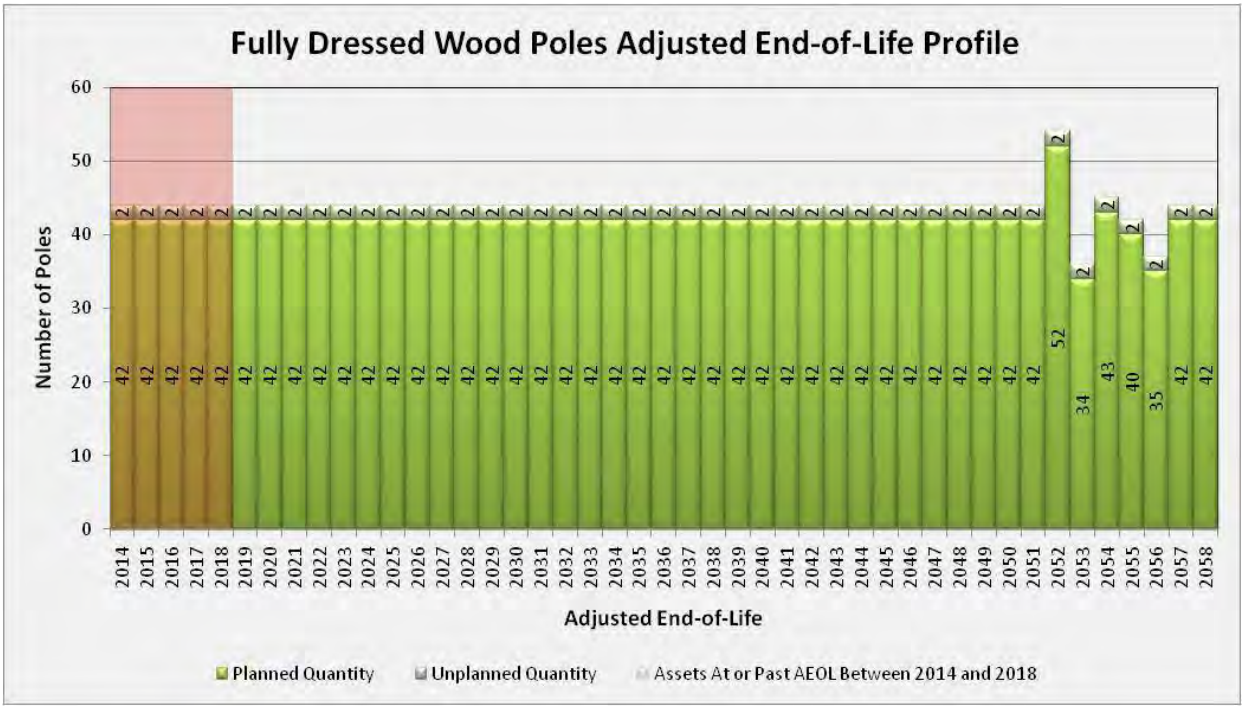
5.3.2.2.e.iii.1.b Fully Dressed Wood Poles Adjusted End-of-Life Projections

FFPC performs detailed inspections, as well as a pole condition testing on every pole, on a three year cycle. The results of the inspections and condition tests are used to project the date when the pole is expected to be at the end of its useful service life due to deterioration. FFPC terms this projection as the "Adjusted End-of-Life" (AEOL) date, as per FFPC's asset management process. Favourable inspection and condition testing results extend an asset's AEOL date beyond its TUL and alternately, unfavourable inspection and condition testing results will shorten an asset's AEOL date, with respect to its original TUL date assigned. It is important to note that adjusted AEOL projections are more meaningful as assets approach their TUL, as opposed during their early years of service. The timeframe when assets approach their TUL is the critical time at which investment and planning decisions must be made. FFPC's long term planning strategy is to establish and maintain evenly distributed asset populations. Due to wood poles failures posing a hazard to employees, the general public as well as undermining the structural integrity of the overhead distribution system, FFPC's strategy is to replace them just prior to their deemed failure. Just in time proactive replacements allows for the replacement to be conducted in a coordinated and planned manner, as opposed to under emergency repair circumstances, which often add unnecessary risk and expense.

The following table and graph represent FFPC's anticipated pole replacement schedule, over one complete typical lifecycle of 45 years. FFPC started replacing poles using the AEOL methodology in 2010. It is also important to note that wood poles frequently (on average two per year) fail prematurely, due to sudden devastating damage incurred by external influence such as wood peckers, snow ploughs or pole fires. As such, FFPC anticipates having to replace a slightly larger number of poles than are currently in the population. FFPC estimates that it will require approximately 1974 poles to

sustain the existing population of 1776 over one complete 45 year lifecycle. FFPC expects that on average two poles per year will require replacement due to sudden unforeseen crippling damage. Wood pole replacements have been identified as having a significant impact on the DS Plan.

Fully Dressed Wood Poles Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)					
Lifecycle Year	**Adjusted End-of-Life Year**	**Planned Quantity**	**Unplanned Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**42**	**2**	**$ 129,928**	**39.5**
2	**2015**	**42**	**2**	**$ 129,928**	**39.5**
3	**2016**	**42**	**2**	**$ 129,928**	**39.5**
4	**2017**	**42**	**2**	**$ 129,928**	**39.5**
5	**2018**	**42**	**2**	**$ 129,928**	**39.5**
6	2019	42	2	$ 129,928	39.5
7	2020	42	2	$ 129,928	39.5
8	2021	42	2	$ 129,928	39.5
9	2022	42	2	$ 129,928	39.5
10	2023	42	2	$ 129,928	39.5
11	2024	42	2	$ 129,928	39.5
12	2025	42	2	$ 129,928	39.5
13	2026	42	2	$ 129,928	39.5
14	2027	42	2	$ 129,928	39.5
15	2028	42	2	$ 129,928	39.5
16	2029	42	2	$ 129,928	39.5
17	2030	42	2	$ 129,928	39.5
18	2031	42	2	$ 129,928	39.5
19	2032	42	2	$ 129,928	39.5
20	2033	42	2	$ 129,928	39.5
21	2034	42	2	$ 129,928	39.5
22	2035	42	2	$ 129,928	39.5
23	2036	42	2	$ 129,928	39.5
24	2037	42	2	$ 129,928	39.5
25	2038	42	2	$ 129,928	39.5
26	2039	42	2	$ 129,928	39.5
27	2040	42	2	$ 129,928	39.5
28	2041	42	2	$ 129,928	39.5
29	2042	42	2	$ 129,928	39.5
30	2043	42	2	$ 129,928	39.5
31	2044	42	2	$ 129,928	39.5
32	2045	42	2	$ 129,928	39.5
33	2046	42	2	$ 129,928	39.5
34	2047	42	2	$ 129,928	39.5
35	2048	42	2	$ 129,928	39.5
36	2049	42	2	$ 129,928	39.5
37	2050	42	2	$ 129,928	39.5
38	2051	42	2	$ 129,928	39.5
39	2052	52	2	$ 156,717	39.5
40	2053	34	2	$ 112,515	39.5
41	2054	43	2	$ 142,652	39.5
42	2055	40	2	$ 127,249	39.5
43	2056	35	2	$ 115,863	39.5
44	2057	42	2	$ 128,588	39.5
45	2058	42	2	$ 129,928	39.5
Totals		**1884**	**90**		**1776**



5.3.2.2.e.iii.1.c Lifecycle Analysis Summary & Budget Allocation

Fully Dressed Wood Poles			
1776	Quantity	41.4	10 Year Historic Replacement/Installation Rate (Units/Year)
45	UL	220	Quantity Reaching Adjusted End of Life Over Forecast Period
21.8	Average Age of Population	$649,638	Total Capital Replacement Cost over Forecast Period
39.47	Ideal Equalized Annual Replacement Rate (Units/Yr)	$30,000	Total Capital Refurbishment Cost over Forecast Period
48.4%	% UL Consumed	44.00	Average Replacements Per Year
59.5%	2019 % UL Consumed with no Reinvestment	$135,928	Average Annual Cost Per Year
		$130,017	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$649,638	2014 - 2018 Total Allocated Capital Replacement Amount
		$30,000	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 1776 wood poles is fairly evenly distributed over one lifecycle period beginning in 2014. The population is therefore not skewed, and as such, approximately the same number of assets will require replacement over the first and second half of the lifecycle. FFPC adopted a UL of 45 years, and based on the average age of 21.8 years for the population, 48.4% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 59.5% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced an average of 41.4 poles per year, which is aligned with the ideal average annual

replacement rate of 39.5 poles per year, which does not take into account failures due to external interference or manufacturing flaws. Over the 2014 to 2018 forecast period, an estimated 220 poles will reach their AEOL, requiring replacement. The total estimated capital replacement cost is $649,638 and $30,000 for capital refurbishment is required (failing insulators identified from inspection process). The average annual replacement rate is 44 poles per year, and the average annual total reinvestment is $135,928 per year. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $130,017 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated a total of $649,638 towards capital replacements and $30,000 for capital refurbishments over the 2014 to 2018 planning period. This is closely aligned with the ideal average annual reinvestment need and accomplishes FFPC's objective to keep pace with the rate of asset deterioration.

5.3.2.2.e.iii.1.d Impact of Fully Dressed Wood Poles on DS Plan

The planned replacement of wood poles, based on the output of FFPC's asset management process, will have a significant impact on the DS Plan. FFPC plans to replace 220 poles during the 2014 to 2018 planning period, at a total estimated replacement cost of $649,638, which represents 18.4% of all planned capital expenditures.

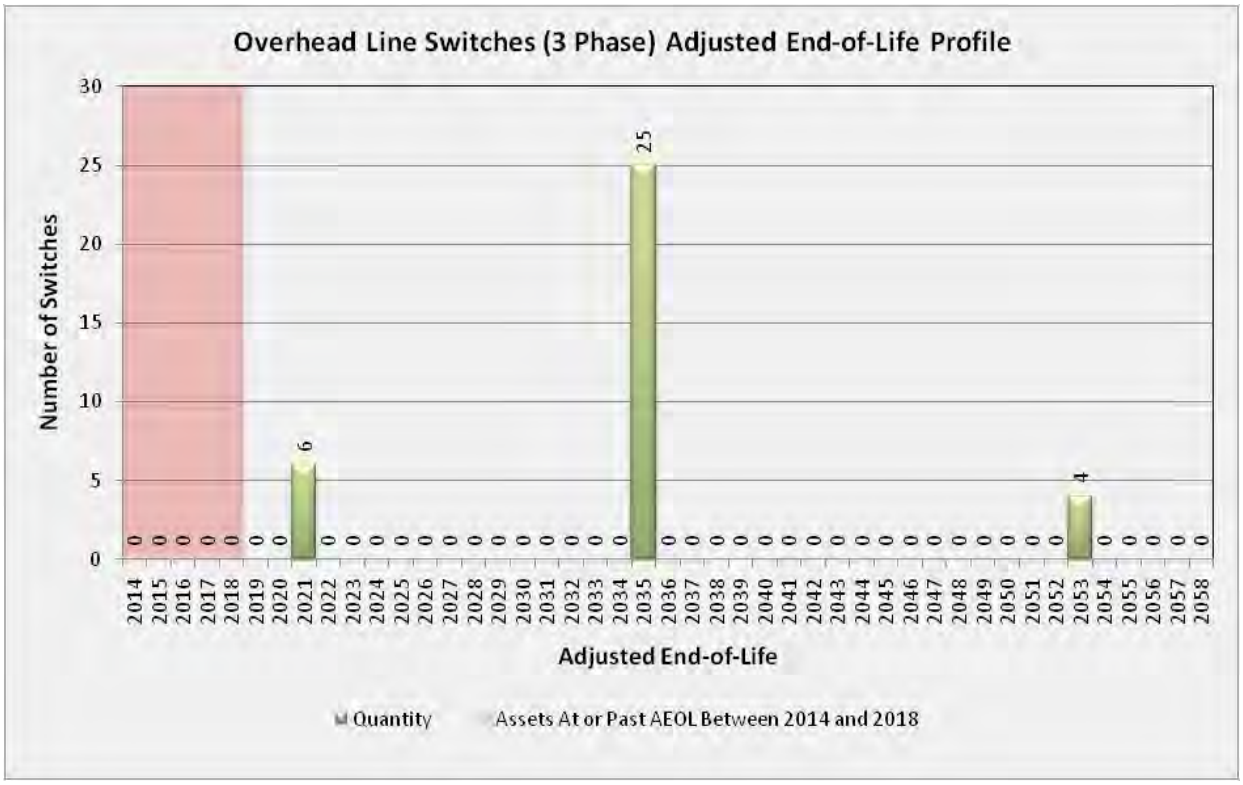
5.3.2.2.e.iii.2 Overhead Line Switches

FFPC currently utilizes three types of overhead line switches that are grouped into this category. FFPC has manual gang operated sectionalizing switches, inline paralleling switches, as well as inline fused switches, all of which are three phase switch settings. FFPC uses the manual gang operated switches to sectionalize its feeders in the event of feeder damage, or if back-feeding of a feeder section is necessary. FFPC utilizes its paralleling switches to be able to energize feeder sections from adjacent feeders, under abnormal operating conditions. The sectionalizing switches combined with the paralleling switches, ultimately give FFPC the flexibility to isolate radial feeder sections, and to back-feed sections thereby minimizing customer impact of power outages. Radial feeders by nature only have one source and if a section of feeder was to be isolated, any section downstream would also be without a supply of power. Thus, paralleling allows for islanded feeder sections to be energized from adjacent feeders. The third type of overhead line switches are inline fused switches. The inline fused switches are designed to operate in conjunction with the feeder reclosers that are located at the transformer station. The fused switches allow for isolation of line sections in the event of a line fault. A tree falling onto a power line would be an example of this type of fault. The fused switch would be activated to isolate the fault condition, and the transformer station recloser (for the feeder) would restore power to the section of distribution line upstream of the fused switch. This again minimizes the number of customer interruptions in the event of a line fault.

5.3.2.2.e.iii.2.a Overhead Line Switches Age Profile Relative to TUL

FFPC has adopted a TUL value of 45 years as per the "Kinectrics Report" for all of its overhead line switches. The following table and graph illustrate the age profile of FFPC's overhead line switches, with respect to the TUL of 45 Years, over one typical lifecycle.

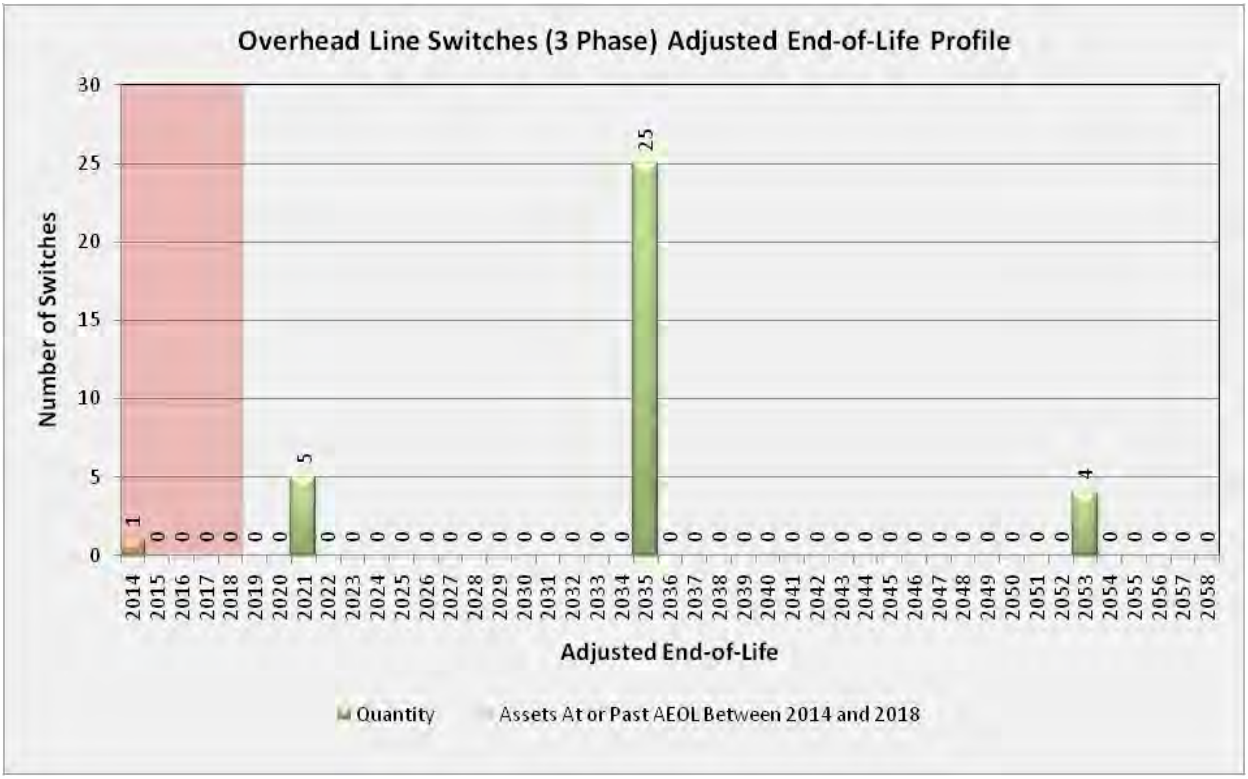
Overhead Line Switches Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 45 Year TUL)**	**Quantity**
1969	**45**	**2014**	**0**
1970	**44**	**2015**	**0**
1971	**43**	**2016**	**0**
1972	**42**	**2017**	**0**
1973	**41**	**2018**	**0**
1974	40	2019	0
1975	39	2020	0
1976	38	2021	6
1977	37	2022	0
1978	36	2023	0
1979	35	2024	0
1980	34	2025	0
1981	33	2026	0
1982	32	2027	0
1983	31	2028	0
1984	30	2029	0
1985	29	2030	0
1986	28	2031	0
1987	27	2032	0
1988	26	2033	0
1989	25	2034	0
1990	24	2035	25
1991	23	2036	0
1992	22	2037	0
1993	21	2038	0
1994	20	2039	0
1995	19	2040	0
1996	18	2041	0
1997	17	2042	0
1998	16	2043	0
1999	15	2044	0
2000	14	2045	0
2001	13	2046	0
2002	12	2047	0
2003	11	2048	0
2004	10	2049	0
2005	9	2050	0
2006	8	2051	0
2007	7	2052	0
2008	6	2053	4
2009	5	2054	0
2010	4	2055	0
2011	3	2056	0
2012	2	2057	0
2013	1	2058	0
Total			**35**



5.3.2.2.e.iii.2.b Overhead Line Switches Adjusted End-of-Life Projections

Overhead line switches are also part of FFPC's three-year inspection and condition testing cycle. Recent inspection and condition test results found that overall the switches are in fair working condition relative to their age; however, one switch was found to be in a poor location. Due to the recent construction of a new elementary school, the air break switch is now located in close proximity to the main entrance of the school yard. FFPC plans to replace the switch and at the same time to relocate it to a more suitable location. The inspections also found the insulators on the gang operated sectionalizing switches to be in poor condition, posing a high risk of failure due to potential tracking occurring. As such, FFPC replaced half of the insulators as part of its 2013 asset sustainment program, and is planning to replace the second half of insulators under the 2014 asset sustainment program. Given the current operating conditions and maintenance practices, FFPC expects that all but one switch will achieve or surpass their UL of 45 years. Over the 2014 to 2018 planning period, FFPC plans to relocate and replace one air break switch at an estimated cost of $28,000, as well as to replace $4,500 worth of insulators in 2014. The following table and graph illustrate the adjusted end-of-life profile for FFPC's overhead line switches based on the most recent inspection and condition testing results.

Overhead Line Switches Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**1**	**$ 28,000**	**0.8**
2	**2015**	**0**	**$ -**	**0.8**
3	**2016**	**0**	**$ -**	**0.8**
4	**2017**	**0**	**$ -**	**0.8**
5	**2018**	**0**	**$ -**	**0.8**
6	2019	0	$ -	0.8
7	2020	0	$ -	0.8
8	2021	5	$ 140,000	0.8
9	2022	0	$ -	0.8
10	2023	0	$ -	0.8
11	2024	0	$ -	0.8
12	2025	0	$ -	0.8
13	2026	0	$ -	0.8
14	2027	0	$ -	0.8
15	2028	0	$ -	0.8
16	2029	0	$ -	0.8
17	2030	0	$ -	0.8
18	2031	0	$ -	0.8
19	2032	0	$ -	0.8
20	2033	0	$ -	0.8
21	2034	0	$ -	0.8
22	2035	25	$ 81,904	0.8
23	2036	0	$ -	0.8
24	2037	0	$ -	0.8
25	2038	0	$ -	0.8
26	2039	0	$ -	0.8
27	2040	0	$ -	0.8
28	2041	0	$ -	0.8
29	2042	0	$ -	0.8
30	2043	0	$ -	0.8
31	2044	0	$ -	0.8
32	2045	0	$ -	0.8
33	2046	0	$ -	0.8
34	2047	0	$ -	0.8
35	2048	0	$ -	0.8
36	2049	0	$ -	0.8
37	2050	0	$ -	0.8
38	2051	0	$ -	0.8
39	2052	0	$ -	0.8
40	2053	4	$ 4,505	0.8
41	2054	0	$ -	0.8
42	2055	0	$ -	0.8
43	2056	0	$ -	0.8
44	2057	0	$ -	0.8
45	2058	0	$ -	0.8
Total		**35**	**$ 254,409**	**35**



5.3.2.2.e.iii.2.c Lifecycle Analysis Summary & Budget Allocation

Overhead Line Switches Profile			
35	Quantity	0.4	10 Year Historic Replacement/Installation Rate (Units/Year)
45	UL	1	Quantity Reaching Adjusted End of Life Over Forecast Period
24.3	Average Age of Population	$28,000	Total Capital Replacement Cost over Forecast Period
0.78	Ideal Equalized Annual Replacement Rate (Units/Yr)	$4,500	Total Capital Refurbishment Cost over Forecast Period
54.1%	% UL Consumed	0.20	Average Replacements Per Year
65.2%	2019 % UL Consumed with no Reinvestment	$6,500	Average Annual Cost Per Year
		$5,654	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$28,000	2014 - 2018 Total Allocated Capital Replacement Amount
		$4,500	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 35 overhead line switch settings is not evenly distributed over one lifecycle period beginning in 2014. The population is not densely populated, such that replacement needs are sporadic and thus not very uniform in nature. FFPC adopted a UL of 45 years, and based on the average age of 24.3 years for the population, 54.1% UL has been consumed. If FFPC was not to

reinvest into this asset class, the percentage of UL consumed increases to 59.5% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced or installed an average of 0.4 switches per year, which is slightly lower than the ideal average annual replacement rate of 0.8 switches per year. Over the 2014 to 2018 forecast period, no switch will reach or surpass its UL of 45 years; however, one switch will reach it AEOL due to it posing a potential safety hazard. The total estimated capital replacement (cost to replace and relocate) cost is $28,000 and $4,500 for capital refurbishment is required. The average annual replacement rate is 0.2 switches per year, and the average total annual reinvestment cost is $6,500 per year. The average annual reinvestment need for this asset class, assuming an evenly distributed population is $5,654 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated $28,000 toward capital replacements and $6,500 for capital refurbishment. This is closely aligned with the ideal average annual reinvestment need, and is also aligned with FFPC's objective of keeping pace with the rate of asset deterioration.

5.3.2.2.e.iii.2.d Impact of Overhead Line Switches on DS Plan

The planned air break switch and insulator replacements in 2014 have a very small impact on FFPC's DS Plan. The total combined capital cost of $32,500 represents 0.9% of the total planned capital expenditures over the 2014 to 2018 planning horizon.

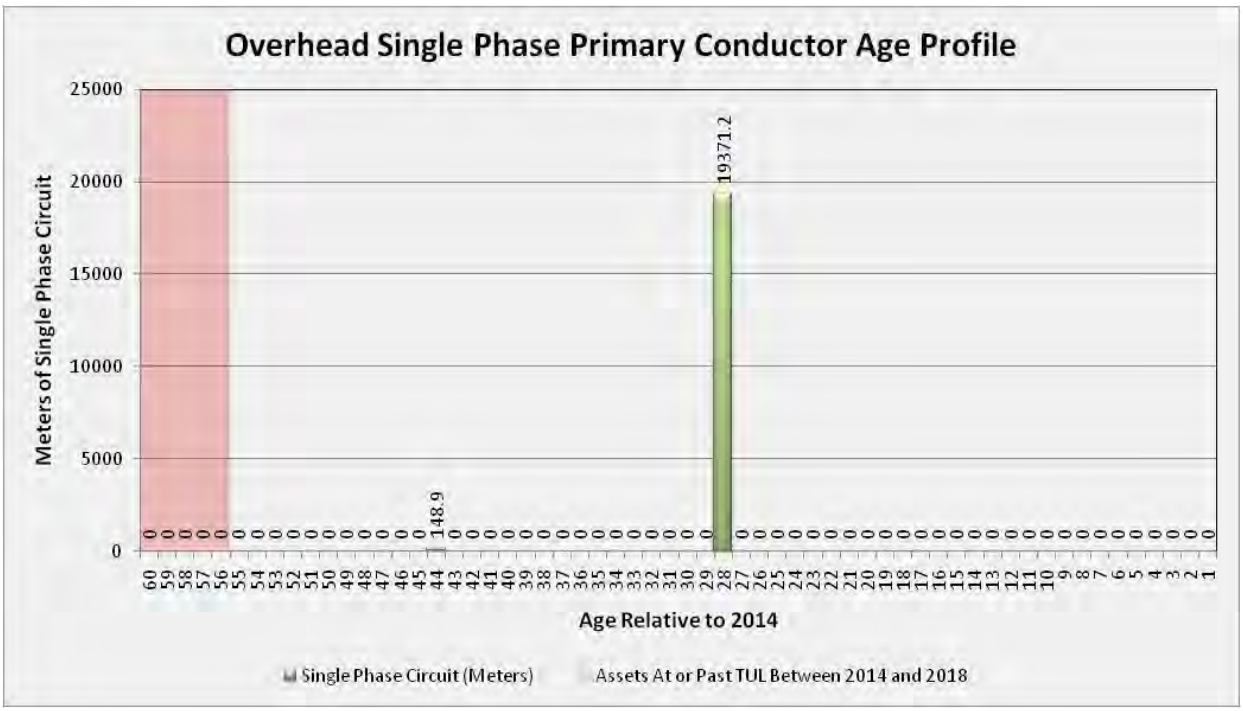
5.3.2.2.e.iii.3 Overhead Conductors

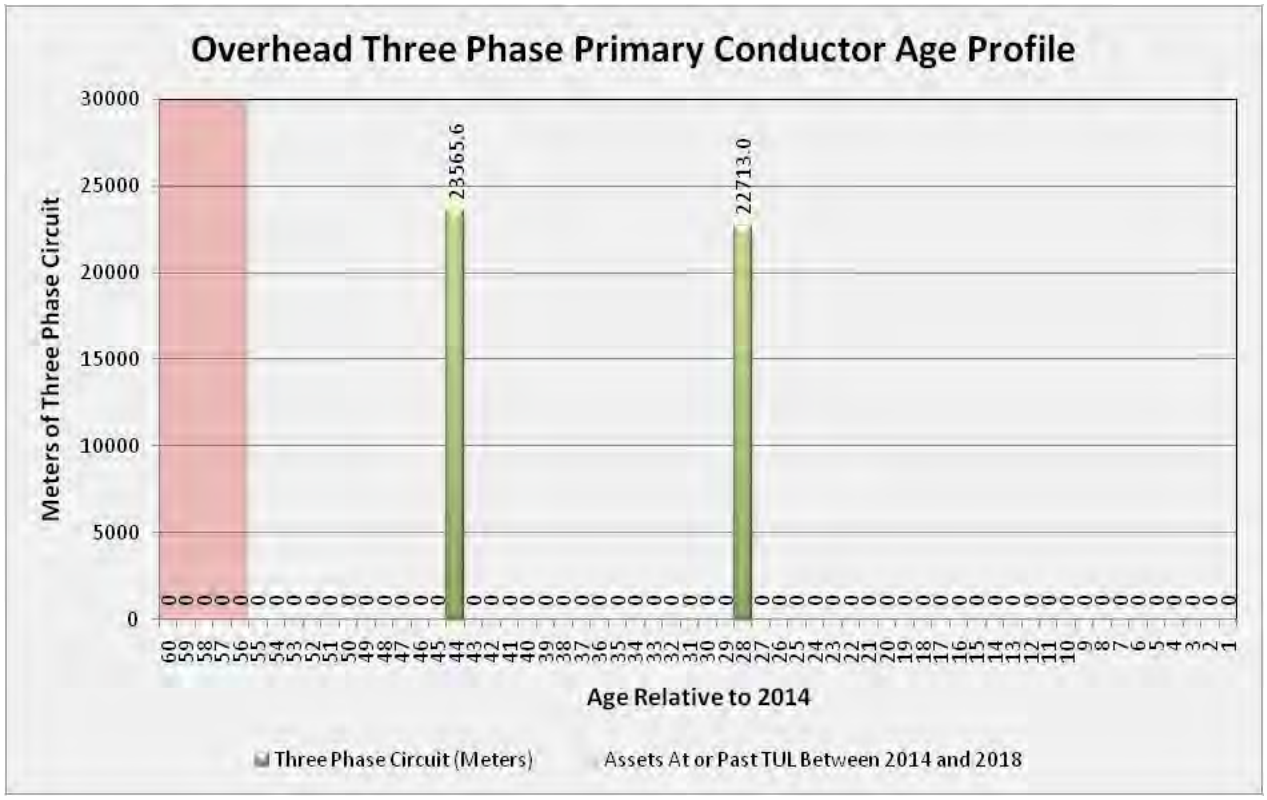
Over the course of history, FFPC's distribution system was reconductored over very short periods of time. Exact dates of individual overhead conductor runs are not known; however, the type of conductor used allowed FFPC to estimate their vintage. In recent history, there has not been a need for FFPC to undertake any feeder reconductoring or overhead expansions activities. The main trunks of the radial feeders are mostly three-phase circuits, with a combined ampacity limit corresponding to approximately 10 MW. FFPC has recorded the properties of individual primary overhead conductor runs, such as their length, type of conductor and wire gauge. FFPC has also started to record the properties of its secondary overhead conductor runs; however, the available data is limited to the conductor runs along distribution pole lines. As such, individual lengths of secondary conductor from the distribution transformer to individual customer premises are not yet know. FFPC is planning on continuing with its GIS mapping initiative, and hopes to have all secondary conductor runs assessed by 2018.

5.3.2.2.e.iii.3.a Overhead Primary Conductors Age Profile Relative to TUL

FFPC has adopted a TUL value of 60 years for overhead primary conductors as per "Kinectrics Report". FFPC has further divided its overhead conductor runs into Single Phase and Three Phase classes. The following table and graphs illustrate the age profile of FFPC's single phase and three phase overhead distribution lines, with respect to a 60 year TUL over one lifecycle.

Overhead Primary Conductor Age Profile (Relative to 2014 - Based on July 2013 Data)				
In Service Year	Age	End-of-Life (Based on 45 Year TUL)	Single Phase Circuit (Meters)	Three Phase Circuit (Meters)
1954	**60**	**2014**	**0**	**0**
1955	**59**	**2015**	**0**	**0**
1956	**58**	**2016**	**0**	**0**
1957	**57**	**2017**	**0**	**0**
1958	**56**	**2018**	**0**	**0**
1959	55	2019	0	0
1960	54	2020	0	0
1961	53	2021	0	0
1962	52	2022	0	0
1963	51	2023	0	0
1964	50	2024	0	0
1965	49	2025	0	0
1966	48	2026	0	0
1967	47	2027	0	0
1968	46	2028	0	0
1969	45	2029	0	0
1970	44	2030	148.9	23565.6
1971	43	2031	0	0
1972	42	2032	0	0
1973	41	2033	0	0
1974	40	2034	0	0
1975	39	2035	0	0
1976	38	2036	0	0
1977	37	2037	0	0
1978	36	2038	0	0
1979	35	2039	0	0
1980	34	2040	0	0
1981	33	2041	0	0
1982	32	2042	0	0
1983	31	2043	0	0
1984	30	2044	0	0
1985	29	2045	0	0
1986	28	2046	19371.2	22713.0
1987	27	2047	0	0
1988	26	2048	0	0
1989	25	2049	0	0
1990	24	2050	0	0
1991	23	2051	0	0
1992	22	2052	0	0
1993	21	2053	0	0
1994	20	2054	0	0
1995	19	2055	0	0
1996	18	2056	0	0
1997	17	2057	0	0
1998	16	2058	0	0
1999	15	2059	0	0
2000	14	2060	0	0
2001	13	2061	0	0
2002	12	2062	0	0
2003	11	2063	0	0
2004	10	2064	0	0
2005	9	2065	0	0
2006	8	2066	0	0
2007	7	2067	0	0
2008	6	2068	0	0
2009	5	2069	0	0
2010	4	2070	0	0
2011	3	2071	0	0
2012	2	2072	0	0
2013	1	2073	0	0
Totals			**19,520.1**	**46,278.6**

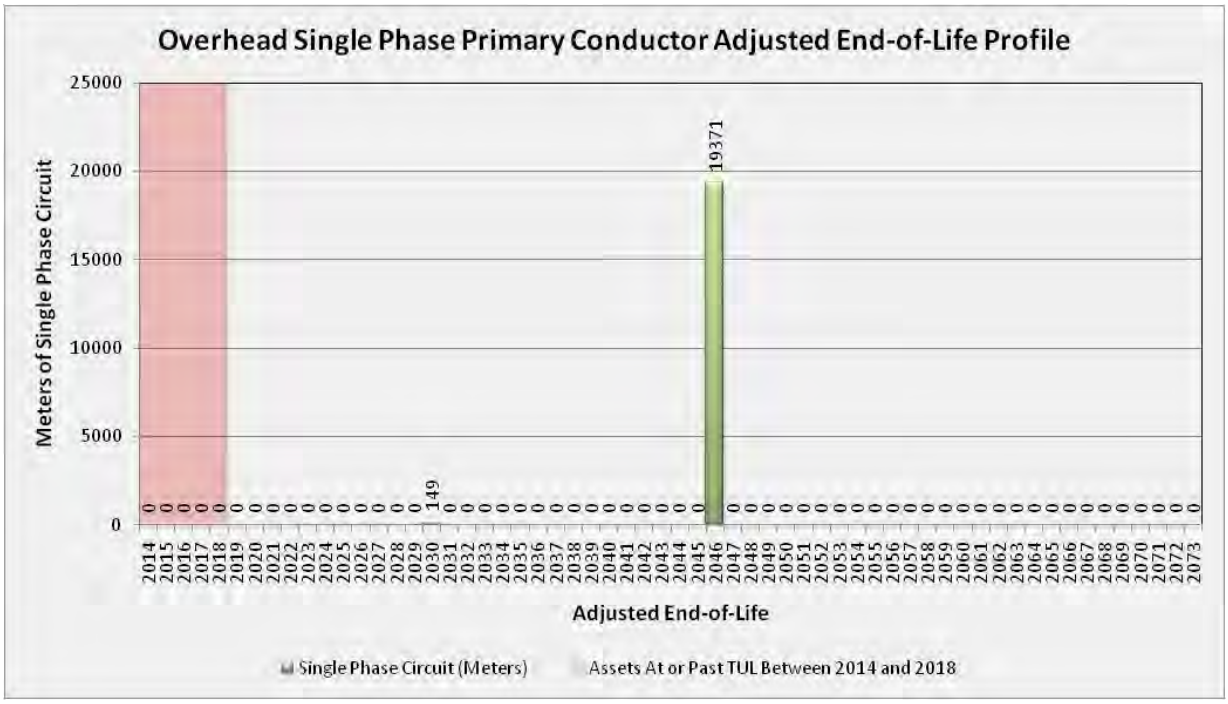

Overhead Single Phase Primary Conductor Age Profile
Meters of Single Phase Circuit
25000
20000
15000
10000
5000
0
19371.2
148.9
Age Relative to 2014
Single Phase Circuit (Meters)
Assets At or Past TUL Between 2014 and 2018

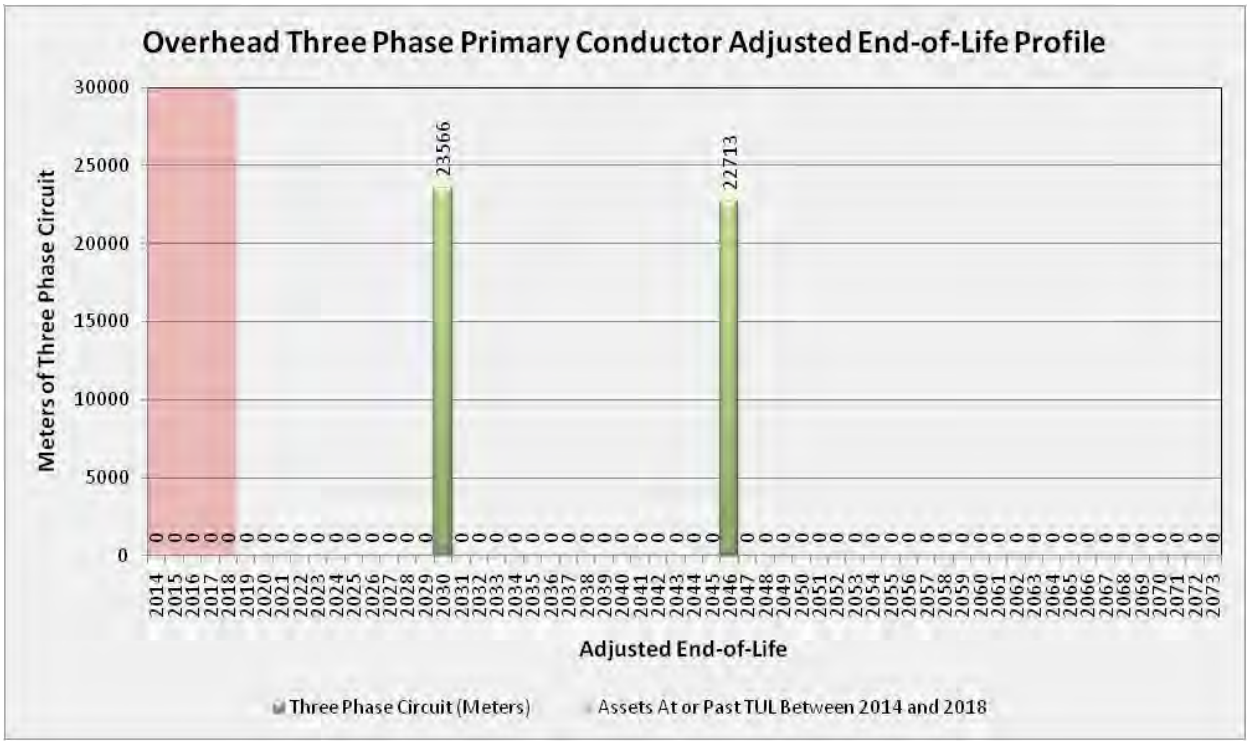

Overhead Three Phase Primary Conductor Age Profile
Meters of Three Phase Circuit
30000
25000
20000
15000
10000
5000
0
23565.6
22713.0
Age Relative to 2014
Three Phase Circuit (Meters)
Assets At or Past TUL Between 2014 and 2018

5.3.2.2.e.iii.3.b Overhead Primary Conductors Adjusted End-of-Life Projections

FFPC also performs detailed inspections of its overhead conductors on a three year cycle. The results of the inspections may trigger condition testing if deterioration is observed. To date, FFPC's inspections have not triggered the need for condition testing. FFPC anticipates that the conductors will achieve or surpass their UL of 60 years. FFPC has set the adjusted useful life dates to correspond to a 60 year TUL. FFPC does not expect to incur any reconductoring expenses for primary conductor over the 2014 to 2018 planning period. FFPC does plan; however, to extend its "West Feeder" to eliminate the Long Term Load Transfers with Hydro One Networks Inc, as per the requirement of the DSC. This topic is further discussed in Section 5.4.5.2.a.vi "Elimination of Long Term Load Transfers". The following table and graphs illustrate the adjusted end-of-life projections for FFPC's single phase and three phase overhead conductor runs.

Overhead Primary Conductor Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)						
Lifecycle Year	**Adjusted End-of-Life Year**	**Single Phase Circuit (Meters)**	**Three Phase Circuit (Meters)**	**Estimated Single Phase Replacement Cost**	**Estimated Three Phase Replacement Cost**	**Estimated Total Replacement Cost**
1	**2014**	**0**	**0**	**$ -**	**$ -**	**$ -**
2	**2015**	**0**	**0**	**$ -**	**$ -**	**$ -**
3	**2016**	**0**	**0**	**$ -**	**$ -**	**$ -**
4	**2017**	**0**	**0**	**$ -**	**$ -**	**$ -**
5	**2018**	**0**	**0**	**$ -**	**$ -**	**$ -**
6	2019	0	0	$ -	$ -	$ -
7	2020	0	0	$ -	$ -	$ -
8	2021	0	0	$ -	$ -	$ -
9	2022	0	0	$ -	$ -	$ -
10	2023	0	0	$ -	$ -	$ -
11	2024	0	0	$ -	$ -	$ -
12	2025	0	0	$ -	$ -	$ -
13	2026	0	0	$ -	$ -	$ -
14	2027	0	0	$ -	$ -	$ -
15	2028	0	0	$ -	$ -	$ -
16	2029	0	0	$ -	$ -	$ -
17	2030	149	23,566	$ 899	$ 284,446	$ 285,345
18	2031	0	0	$ -	$ -	$ -
19	2032	0	0	$ -	$ -	$ -
20	2033	0	0	$ -	$ -	$ -
21	2034	0	0	$ -	$ -	$ -
22	2035	0	0	$ -	$ -	$ -
23	2036	0	0	$ -	$ -	$ -
24	2037	0	0	$ -	$ -	$ -
25	2038	0	0	$ -	$ -	$ -
26	2039	0	0	$ -	$ -	$ -
27	2040	0	0	$ -	$ -	$ -
28	2041	0	0	$ -	$ -	$ -
29	2042	0	0	$ -	$ -	$ -
30	2043	0	0	$ -	$ -	$ -
31	2044	0	0	$ -	$ -	$ -
32	2045	0	0	$ -	$ -	$ -
33	2046	19,371	22,713	$ 116,909	$ 274,155	$ 391,064
34	2047	0	0	$ -	$ -	$ -
35	2048	0	0	$ -	$ -	$ -
36	2049	0	0	$ -	$ -	$ -
37	2050	0	0	$ -	$ -	$ -
38	2051	0	0	$ -	$ -	$ -
39	2052	0	0	$ -	$ -	$ -
40	2053	0	0	$ -	$ -	$ -
41	2054	0	0	$ -	$ -	$ -
42	2055	0	0	$ -	$ -	$ -
43	2056	0	0	$ -	$ -	$ -
44	2057	0	0	$ -	$ -	$ -
45	2058	0	0	$ -	$ -	$ -
46	2059	0	0	$ -	$ -	$ -
47	2060	0	0	$ -	$ -	$ -
48	2061	0	0	$ -	$ -	$ -
49	2062	0	0	$ -	$ -	$ -
50	2063	0	0	$ -	$ -	$ -
51	2064	0	0	$ -	$ -	$ -
52	2065	0	0	$ -	$ -	$ -
53	2066	0	0	$ -	$ -	$ -
54	2067	0	0	$ -	$ -	$ -
55	2068	0	0	$ -	$ -	$ -
56	2069	0	0	$ -	$ -	$ -
57	2070	0	0	$ -	$ -	$ -
58	2071	0	0	$ -	$ -	$ -
59	2072	0	0	$ -	$ -	$ -
60	2073	0	0	$ -	$ -	$ -
Totals		**19,520**	**46,279**	**$ 117,808**	**$ 558,601**	**$ 676,409**


Overhead Single Phase Primary Conductor Adjusted End-of-Life Profile
Meters of Single Phase Circuit
25000
20000
15000
10000
5000
0
19371
149
Adjusted End-of-Life
Single Phase Circuit (Meters)
Assets At or Past TUL Between 2014 and 2018


Overhead Three Phase Primary Conductor Adjusted End-of-Life Profile
Meters of Three Phase Circuit
30000
25000
20000
15000
10000
5000
0
23566
22713
Adjusted End-of-Life
Three Phase Circuit (Meters)
Assets At or Past TUL Between 2014 and 2018

5.3.2.2.e.iii.3.c Lifecycle Analysis Summary & Budget Allocation

Overhead Primary Single Phase Circuit Conductor Profile			
19,520	Quantity (Meters)	0	10 Year Historic Replacement/Installation Rate (Units/Year)
60	UL	0	Quantity Reaching Adjusted End of Life Over Forecast Period
28.1	Average Age of Population	$0	Total Capital Replacement Cost over Forecast Period
325.34	Ideal Equalized Annual Replacement Rate (Meters/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
46.9%	% UL Consumed	0.00	Average Replacements Per Year
55.2%	2019 % UL Consumed with no Reinvestment	$0	Average Annual Cost Per Year
		$1,963	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$0	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

Overhead Primary Three Phase Circuit Conductor Profile			
46,279	Quantity (Meters)	0	10 Year Historic Replacement/Installation Rate (Units/Year)
60	UL	0	Quantity Reaching Adjusted End of Life Over Forecast Period
36.1	Average Age of Population	$0	Total Capital Replacement Cost over Forecast Period
771.31	Ideal Equalized Annual Replacement Rate (Meters/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
60.2%	% UL Consumed	0.00	Average Replacements Per Year
68.6%	2019 % UL Consumed with no Reinvestment	$0	Average Annual Cost Per Year
		$9,310	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$0	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the populations of 19.5 km of single phase circuit and 46.3 km of three phase circuit are not evenly distributed over one lifecycle period beginning in 2014. The populations are not densely populated, such that replacement needs are extremely sporadic and thus not uniform in nature. FFPC adopted a UL of 60 years, and based on the average age of 28.1 years for the population of single phase circuits, 46.9% UL has been consumed. The average age of the three phase circuit population is 36.1 years, and as such 60.2 %UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 55.2% and 68.2% respectively by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC did not replace or install any primary conductors. Over the 2014 to 2018 forecast period, no primary overhead conductor runs will

reach or surpass their UL of 60 years. As such, no replacements or refurbishments are planned over the forecast period. The average total annual reinvestment need for both classes combined is $11,273 per year, assuming evenly distributed populations, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has not allocated any capital towards replacements or refurbishment, as they are not necessary given the nature of this asset class. This will allow FFPC to shift expenditures towards asset classes that require intensified reinvestment to smooth long term spending requirements.

5.3.2.2.e.iii.3.d Impact of Overhead Primary Conductors on DS Plan

As no primary conductor replacements are necessary over the planning period, this asset class will not impact the DS Plan. This will allow for intensified capital reinvestments into asset classes where it is required.

5.3.2.2.e.iii.4 Overhead Secondary Conductor

FFPC performs inspections and condition assessments on overhead secondary conductors as part of its maintenance inspection program that is conducted on a three year cycle. FFPC has adopted a TUL of 40 years for secondary overhead cables. FFPC's overhead secondary conductor runs consist of secondary buses, to which multiple customers are connected to, as well as service conductors that connect customer's services to the secondary bus or directly to transformers.

5.3.2.2.e.iii.4.a Overhead Secondary Conductors Age Profile

Currently secondary buses along distribution pole lines have been mapped in the GIS system; however, service conductors from the pole line (transformer or bus connections) to individual meter bases have not yet been mapped. As such, the complete age profile of individual cable runs is not available yet. FFPC estimates that the average age for secondary conductors is 28 years.

5.3.2.2.e.iii.4.b Overhead Secondary Conductor Adjusted End-of-Life Profile

Adjusted end-of-life projections for individual overhead secondary cable runs are not available yet.

5.3.2.2.e.iii.4.c Lifecycle Analysis Summary & Budget Allocation

The total average annual reinvestment need for this asset class as established by the asset management process is $25,840. The annual reinvestment need is based on the total cost to replace the asset class, divided by the period established by the UL that FFPC adopted ($1,033,603 / 40 years). FFPC has allocated a total of $10,000 for capital overhead service conductor replacements, as well as $40,000 for secondary bus replacements over the planning horizon, which equate to a total annual reinvestment of

$10,000. FFPC's strategy is to complete gathering age profile and condition data, and once it has been obtained, to refine reinvestment needs accordingly.

5.3.2.2.e.iii.4.d Impact of Overhead Secondary Conductor on DS Plan

The planned reinvestment into overhead secondary conductors has a small impact on FFPC's DS Plan. The total replacement cost of $50,000 for overhead secondary service conductor and secondary bus represent 1.4% of the total planned capital expenditures over the 2014 to 2018 planning horizon.

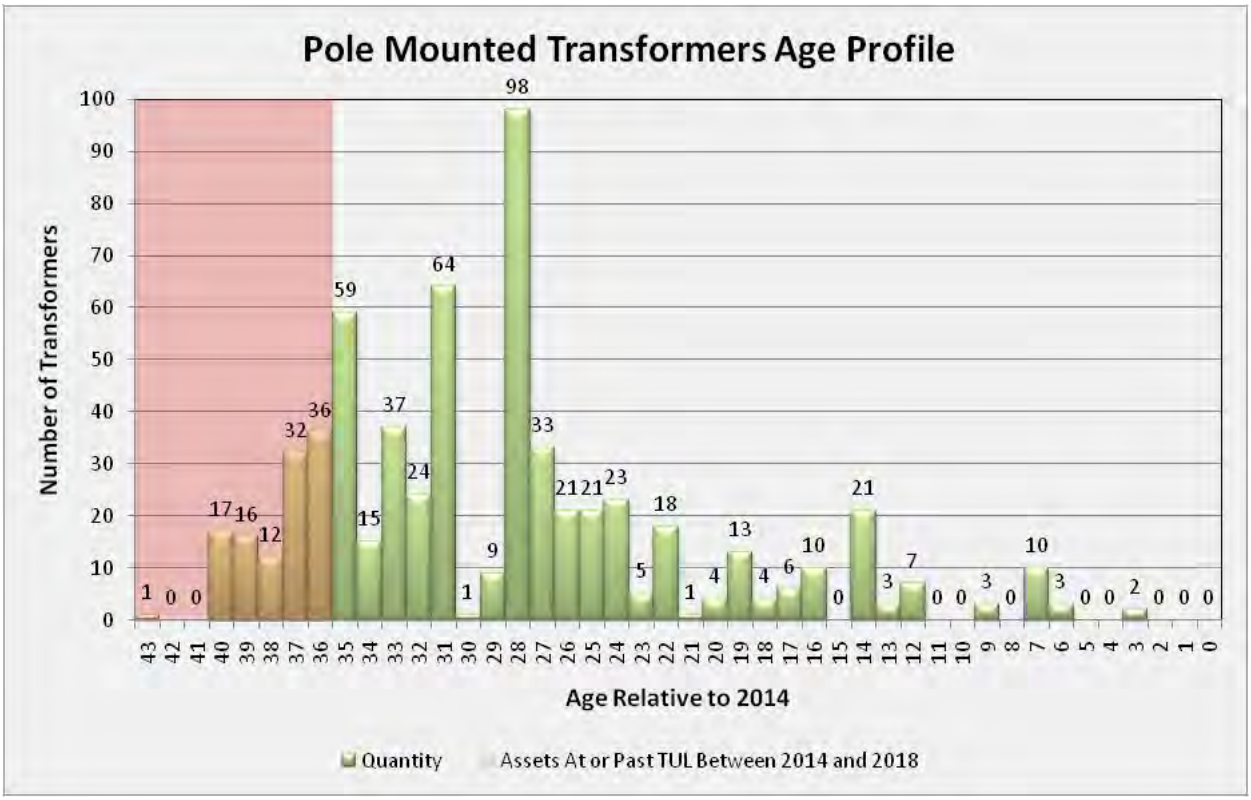
5.3.2.2.e.iii.5 Overhead Transformers

A significant portion of FFPC's asset base is overhead transformers. The overhead transformer fleet consists of 629 single phase units. It is worth mentioning that three phase customers who are supplied from overhead transformers, require three individual single phase transformers that are arranged as a three phase setting (which is an industry standard).

5.3.2.2.e.iii.5.a Overhead Transformers Age Profile Relative to TUL

FFPC has adopted a TUL of 40 years for overhead transformers as per the "Kinectrics Report". As a result of FFPC's system wide voltage conversion and rebuild project, 79% of FFPC's overhead transformers are of 1970s to 1980s vintage. As such, FFPC will experience somewhat of a "tidal wave" affect over the next 20 years as the majority of transformers will have surpassed the end of their useful service life, implying a high risk of failure. FFPC recognizes that it must ramp up its transformer replacements as of 2014. The following table and graph represents the age profile of FFPC's overhead transformers with respect to a TUL of 40 years.

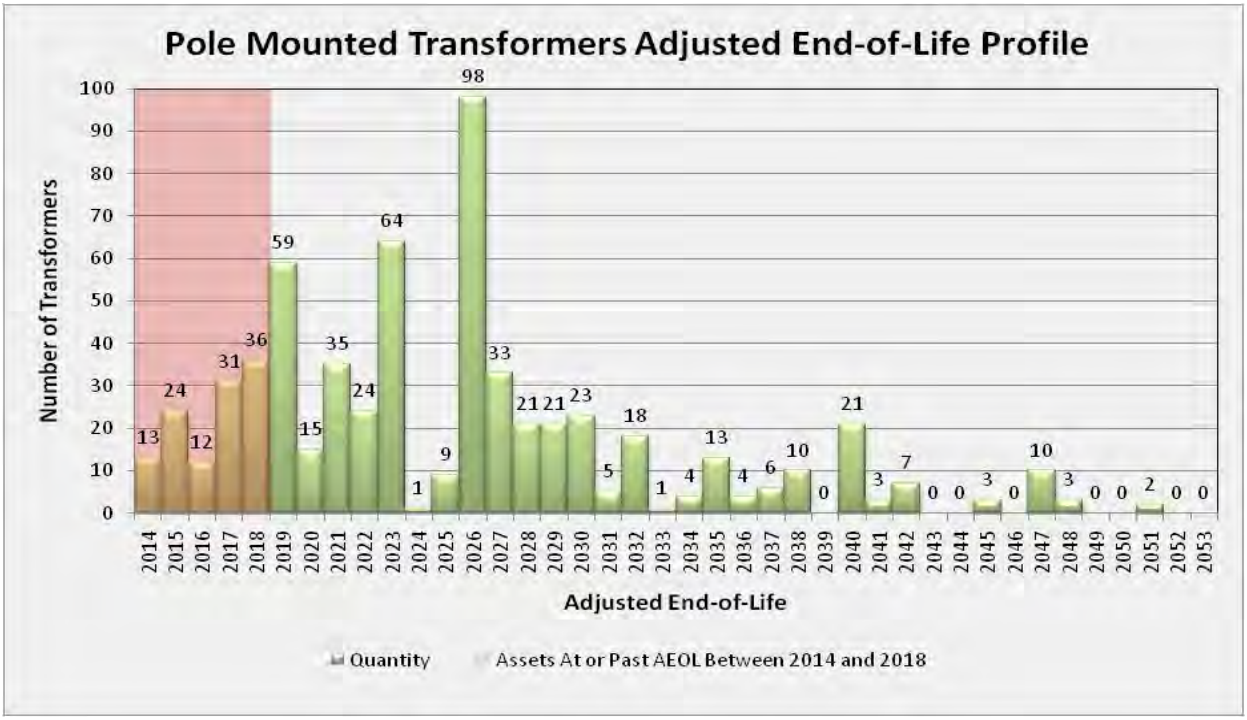
Pole Mounted Transformers Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 40 Year TUL)**	**Quantity**
1971	43	2011	1
1972	42	2012	0
1973	41	2013	0
1974	40	2014	17
1975	39	2015	16
1976	38	2016	12
1977	37	2017	32
1978	36	2018	36
1979	35	2019	59
1980	34	2020	15
1981	33	2021	37
1982	32	2022	24
1983	31	2023	64
1984	30	2024	1
1985	29	2025	9
1986	28	2026	98
1987	27	2027	33
1988	26	2028	21
1989	25	2029	21
1990	24	2030	23
1991	23	2031	5
1992	22	2032	18
1993	21	2033	1
1994	20	2034	4
1995	19	2035	13
1996	18	2036	4
1997	17	2037	6
1998	16	2038	10
1999	15	2039	0
2000	14	2040	21
2001	13	2041	3
2002	12	2042	7
2003	11	2043	0
2004	10	2044	0
2005	9	2045	3
2006	8	2046	0
2007	7	2047	10
2008	6	2048	3
2009	5	2049	0
2010	4	2050	0
2011	3	2051	2
2012	2	2052	0
2013	1	2053	0
2014	0	2054	0
Total			629



5.3.2.2.e.iii.5.b Overhead Transformers Adjusted End-of-Life Projections

FFPC performs detailed inspections of overhead transformers on a three year cycle. The results of the inspections are used to assess the overall health of transformers with respect to age. Physical defects such as oil leaks or cracked bushing indicate that a transformer is very near to the end of its useful service life, with a high probability of failure. FFPC has assigned AEOL dates to individual transformers using FFPC's asset management process. It is important to note that the AEOL values are of higher importance as assets approach their TUL, as opposed to in their earlier years. FFPC is also currently working on recording the relationship of transformers to customers, which will allow for analysis of electrical loading from smart meter data. Smart meter data will essentially give FFPC insight into individual transformer utilization (electrical loading profile). Electrical loading is a large contributor of transformer degradation, and as such, being able to quantify it will greatly enhance FFPC's ability in predicting transformer failure. The following table and graph illustrate the AEOL profile for FFPC's overhead transformers, based on the most recent inspection results.

Pole Mounted Transformers Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**13**	**$ 59,506.00**	**15.725**
2	**2015**	**24**	**$ 104,893.60**	**15.725**
3	**2016**	**12**	**$ 68,081.40**	**15.725**
4	**2017**	**31**	**$ 129,708.80**	**15.725**
5	**2018**	**36**	**$ 129,427.60**	**15.725**
6	2019	59	$ 256,421.80	15.725
7	2020	15	$ 58,781.40	15.725
8	2021	35	$ 144,346.40	15.725
9	2022	24	$ 82,605.80	15.725
10	2023	64	$ 303,640.60	15.725
11	2024	1	$ 6,414.60	15.725
12	2025	9	$ 55,231.40	15.725
13	2026	98	$ 454,834.80	15.725
14	2027	33	$ 143,058.80	15.725
15	2028	21	$ 95,623.20	15.725
16	2029	21	$ 86,829.40	15.725
17	2030	23	$ 122,306.60	15.725
18	2031	5	$ 19,958.40	15.725
19	2032	18	$ 68,962.80	15.725
20	2033	1	$ 2,300.00	15.725
21	2034	4	$ 13,093.80	15.725
22	2035	13	$ 66,389.80	15.725
23	2036	4	$ 20,593.80	15.725
24	2037	6	$ 20,593.80	15.725
25	2038	10	$ 43,146.00	15.725
26	2039	0	$ -	15.725
27	2040	21	$ 91,606.60	15.725
28	2041	3	$ 10,243.80	15.725
29	2042	7	$ 20,998.40	15.725
30	2043	0	$ -	15.725
31	2044	0	$ -	15.725
32	2045	3	$ 10,243.80	15.725
33	2046	0	$ -	15.725
34	2047	10	$ 42,216.80	15.725
35	2048	3	$ 15,525.00	15.725
36	2049	0	$ -	15.725
37	2050	0	$ -	15.725
38	2051	2	$ 3,680.00	15.725
39	2052	0	$ -	15.725
40	2053	0	$ -	15.725
Totals		**629**	**$ 2,751,265.00**	**629**



5.3.2.2.e.iii.5.c Lifecycle Analysis Summary & Budget Allocation

Pole Mounted Transformers Profile			
629	Quantity	1.8	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL	116	Quantity Reaching Adjusted End of Life Over Forecast Period
28.8	Average Age of Population	$491,617	Total Capital Replacement Cost over Forecast Period
15.73	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
72.0%	% UL Consumed	23.20	Average Replacements Per Year
84.5%	2019 % UL Consumed with no Reinvestment	$98,323	Average Annual Cost Per Year
		$68,782	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$491,617	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 629 pole mounted transformers is not evenly distributed over one lifecycle period beginning in 2014. The population has high positive skew, and as such, approximately 86% (543 transformers) will require replacement over the first half of the lifecycle period (over the next 20 years). FFPC adopted a UL of 40 years, and based on the average age of 28.8 years for the population, 72.0% UL has been consumed. If FFPC was not to reinvest into this asset class, the

percentage of UL consumed increases to 84.5% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced an average of 1.8 pole mounted transformers per year, which is significantly lower than the ideal average annual replacement rate of 15.7 pole mounted transformers per year. Over the 2014 to 2018 forecast period, an estimated 116 pole mounted transformers will reach their AEOL, requiring replacement. The total estimated capital replacement cost is $491,617, which has been allocated. No capital refurbishments have been allocated as transformers are not conducive to distributor refurbishing. The average annual replacement rate is projected to be 23.3 transformers per year, and the average total annual reinvestment is $98,323 per year. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $68,782 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated a total of $491,617 towards capital replacements and no capital for refurbishments over the 2014 to 2018 planning period. This is approximately 42% higher than the ideal average annual reinvestment need, due to the large number of projected failures based on the large positive skew of the transformer age profile.

5.3.2.2.e.iii.5.d Impact of Overhead Transformers on DS Plan

The planned reinvestment into pole mounted transformers has a very large impact on FFPC's DS Plan. The total capital replacement cost of $491,617 for the transformers represents 14.0% of the total planned capital expenditures over the 2014 to 2018 planning horizon.

5.3.2.2.f. Underground Distribution System Assets

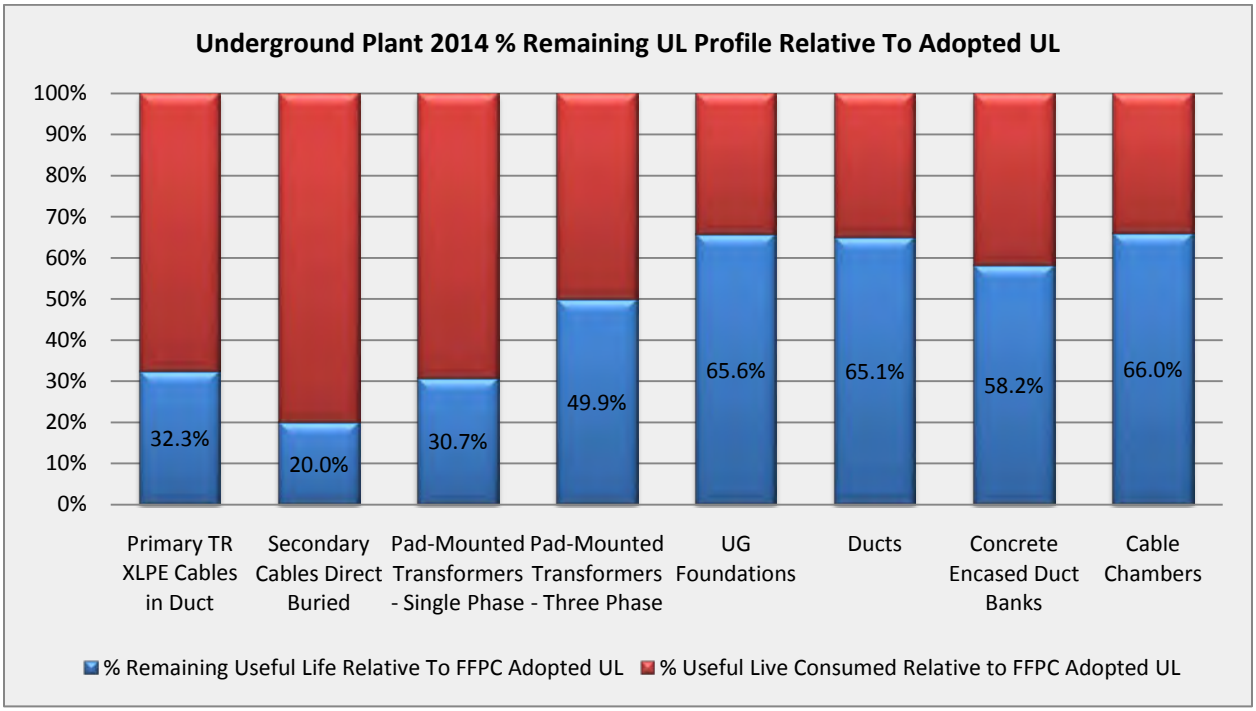
FFPC's underground distribution assets consist mainly of Pad-Mounted Transformer settings and Underground Cable installations. FFPC's underground transformer population consists of 215 single phase and 38 three phase units. All of FFPC's primary underground cables are ducted, where some of the ducts are cement encased for additional protection. FFPC's total conductor length of underground primary cable is 30.7 km (includes the length of conductor that is above ground which is required to connect the shielded cables to the distribution feeders via dip poles). In terms of circuit length or "trench length", the 30.7 km of conductor represent 3.9 km of single phase circuit, 0.5 km of two phase circuit and 6.2 km of three phase circuit. The oldest conductor runs correspond to the construction of the Fort Frances MTS transformer station in the early 1970s.

5.3.2.2.f.i. Underground Plant Lifecycle Profile, Reinvestment Needs Boundaries & Reinvestment Summary

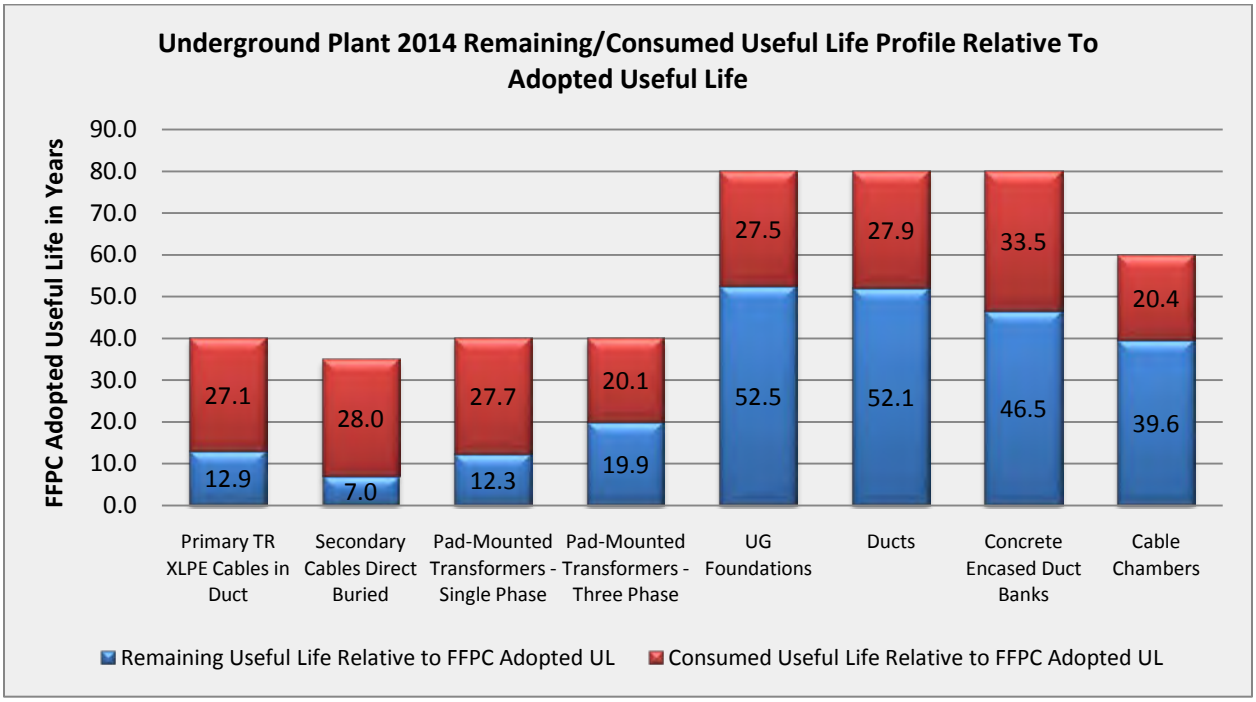
As per the Chapter 5 Filing Requirements guide, FFPC has relied on its newly developed Asset Management Process to collect, tabulate and assess information on physical assets, current and future system operating conditions, and FFPC's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus.

FFPC's asset management process has established a total asset replacement value of $24,379,821 for all existing assets managed, based on FFPC's replacement cost structure. Of this asset base, the replacement value of Underground Plant assets is estimated to be $5,912,815, which is approximately 24.3% of the total replacement value. Based on FFPC's adopted useful life values, the average annual reinvestment needed to keep pace with Underground Plant asset deterioration is $124,638. The overall % remaining useful life (relative to FFPC's adopted UL and replacement cost) is 43.7%. FFPC's long term objective is to maintain a 50% "Remaining UL" profile where possible, to smooth long term spending requirements. As such, FFPC has an optimal capital reinvestment budget allocation of $124,638 to sustain the lifecycle of Underground Plant assets. FFPC has allocated a total of $706,460 towards sustaining the lifecycle of Underground Plant, which equates to an average annual reinvestment of $141,292. This annual investment rate is approximately 13.3% higher than the ideal average annual reinvestment need, as the population has deteriorated well below FFPC's target. The reinvestment will support FFPC's objective of keeping pace with the rate of asset deterioration.

The following graph illustrates the % UL Remaining profile of all Underground Plant asset categories.



The following graph illustrates the remaining and consumed years of all Underground Plant asset categories:



The following tables summarizes planned capital expenditures over the 2014 to 2018 planning horizon, based on assets that were identified to be at the end of their useful service life, as per outputs of Step 4

of the asset management process. Capital expenditures driven by other investment drivers such as the elimination of LTLT's, Customer Preference or Renewable Enabling Improvements are not included in this summary. The table also illustrates the Useful Life and Reinvestment Need analysis for each asset category. Various reinvestment needs boundaries are illustrated representing various adoptions of useful service life philosophies, such as the "Kinectrics Report's" MIN UL, TUL, MAX UL, as well as FFPC's adopted UL.

FFPC Asset Summary, Useful Life Assessment, Investment Boundaries and Capital Budget Allocations

		Asset Details		FFPC Assets			Kinectrics Useful Life			Useful Life Assessment					Reinvestment Needs Assessment					Capital Budget Allocation		
Parent*	#	Category| Component | Type		Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to Kinectrics TUL	% Remaining Useful Life Relative Kinectrics TUL	Remaining Useful Life Relative to FFPC Adopted UL	% Remaining Useful Life Relative To FFPC Adopted UL	Total Replacement Cost of Asset Group	Average Annual Reinvestment Need Based on Kinectrics Min UL	Average Annual Reinvestment Need Based on Kinectrics TUL	Average Annual Reinvestment Need Based on Kinectrics Max UL	Average Annual Reinvestment Need Based on FFPC Adopted UL	Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2014 to 2018)	% of Total DS Plan Capital Expenditures
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		N/A			60	65	75													
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		N/A			20	25	25													
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		N/A			20	25	30													
	27	Primary Non-TR XLPE Cables in Duct		N/A			20	25	30													
	28	Primary TR XLPE Cables Direct Buried		N/A			25	30	35													
	29	Primary TR XLPE Cables in Duct		30.7	km	27.07	35	40	55	40.0	12.9	32.3%	12.9	32.3%	$ 931,695	$ 26,620	$ 23,292	$ 16,940	**$ 23,292**	$ 180,537	$ 36,107	5.1%
	30	Secondary PILC Cables		N/A			70	75	80													
	31	Secondary Cables Direct Buried		3.8	km	28.00	25	35	40	35.0	7.0	20.0%	7.0	20.0%	$ 68,366	$ 2,735	$ 1,953	$ 1,709	**$ 1,953**	$ 10,000	$ 2,000	0.3%
	32	Secondary Cables in Duct		N/A			35	40	60													
	33	Network Transformers	Overall	N/A			20	35	50													
			Protector	N/A			20	35	40													
	34	Pad-Mounted Transformers	Single Phase	215	Each	27.70	25	40	45	40.0	12.3	30.7%	12.3	30.7%	$ 2,218,967	$ 88,759	$ 55,474	$ 49,310	**$ 55,474**	$ 368,761	$ 73,752	10.5%
			Three Phase	38	Each	20.05	25	40	45	40.0	19.9	49.9%	19.9	49.9%	$ 808,033	$ 32,321	$ 20,201	$ 17,956	**$ 20,201**	$ 147,163	$ 29,433	4.2%
	35	Submersible/Vault Transformers		N/A			25	35	45													
	36	UG Foundation		170	Each	27.52	35	55	70	80.0	27.5	50.0%	52.5	65.6%	$ 814,956	$ 23,284	$ 14,817	$ 11,642	**$ 10,187**	$ -	$ -	0.0%
	37	UG Vaults	Overall	N/A			40	60	80													
			Roof	N/A			20	30	45													
	38	UG Vault Switches		N/A			20	35	50													
	39	Pad-Mounted Switchgear		N/A			20	30	45													
	40	Ducts		23.5	km	27.95	30	50	85	80.0	22.1	44.1%	52.1	65.1%	$ 322,801	$ 10,760	$ 6,456	$ 3,798	**$ 4,035**	$ -	$ -	0.0%
	41	Concrete Encased Duct Banks		1.9	km	33.46	35	55	80	80.0	21.5	39.2%	46.5	58.2%	$ 712,998	$ 20,371	$ 12,964	$ 8,912	**$ 8,912**	$ -	$ -	0.0%
	42	Cable Chambers		5	Each	20.40	50	60	80	60.0	39.6	66.0%	39.6	66.0%	$ 35,000	$ 700	$ 583	$ 438	**$ 583**	$ -	$ -	0.0%
Totals															$ 5,912,815	$ 205,550	$ 135,741	$ 110,706	**$ 124,638**	$ 706,460	$ 141,292	20.1%

The following table summarizes FFPC's budgeted capital reinvestments, for each Underground Plant asset category over the 2014 to 2018 planning period. The planned reinvestments are all driven by the outputs of Step 4 of the asset management process, and as such they are allocated towards sustaining the lifecycle of existing assets.

		Asset Details		Capital Budget Allocation		
Parent*	**#**	**Category| Component | Type**		**Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation**	**Average Annual Capital Allocation (2014 to 2018)**	**% of Total DS Plan Capital Expenditures**
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables				
	25	Primary Ethylene-Propylene Rubber (EPR) Cables				
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried				
	27	Primary Non-TR XLPE Cables in Duct				
	28	Primary TR XLPE Cables Direct Buried				
	29	Primary TR XLPE Cables in Duct		$ 180,537	$ 36,107	5.1%
	30	Secondary PILC Cables				
	31	Secondary Cables Direct Buried		$ 10,000	$ 2,000	0.3%
	32	Secondary Cables in Duct				
	33	Network Transformers	Overall			
			Protector			
	34	Pad-Mounted Transformers	Single Phase	$ 368,761	$ 73,752	10.5%
			Three Phase	$ 147,163	$ 29,433	4.2%
	35	Submersible/Vault Transformers				
	36	UG Foundation		$ -	$ -	0.0%
	37	UG Vaults	Overall			
			Roof			
	38	UG Vault Switches				
	39	Pad-Mounted Switchgear				
	40	Ducts		$ -	$ -	0.0%
	41	Concrete Encased Duct Banks		$ -	$ -	0.0%
	42	Cable Chambers		$ -	$ -	0.0%
Totals				$ 706,460	$ 141,292	20.1%

5.3.2.2.f.ii. Underground Distribution System Capacity & Utilization

The underground portions of FFPC's distribution feeders were also designed to accommodate a combined three phase load of 10 MW. Three feeders propagate out of transformer station Fort Frances MTS in underground cement encased ducts. The combined three phase ampacity of the cables also corresponds to a limitation of 10 MW. Refer to the "Transformer Station Capacity Utilization" section for more details.

FFPC is currently mapping out transformer to customer meter relationships to enable individual transformer utilizations to be calculated using smart meter data. FFPC does not have any distribution transformer utilization data available at this time.

5.3.2.2.f.iii. Underground Distribution System Asset Classifications

FFPC has grouped its underground distribution system asset classifications according to the "Kinectrics Report". FFPC does not have assets in many of the groupings and as such they have been omitted. FFPC has assets in the following groupings: Primary TR XLPE Cables in Duct; Secondary Cables Direct Buried; Pad-Mounted Transformers; Underground Foundation; Ducts; Concrete Encased Duct Banks; and Cable Chambers

5.3.2.2.f.iv. Primary TR XLPE Cables in Duct

FFPC's underground primary conductor is used to connect feeders to the transformer station, in newer subdivisions in place of overhead lines, as well as to connect the distribution system to pad-mounted transformers.

5.3.2.2.f.iv.1 Primary TR XLPE Cables in Duct Age Profile Relative to TUL

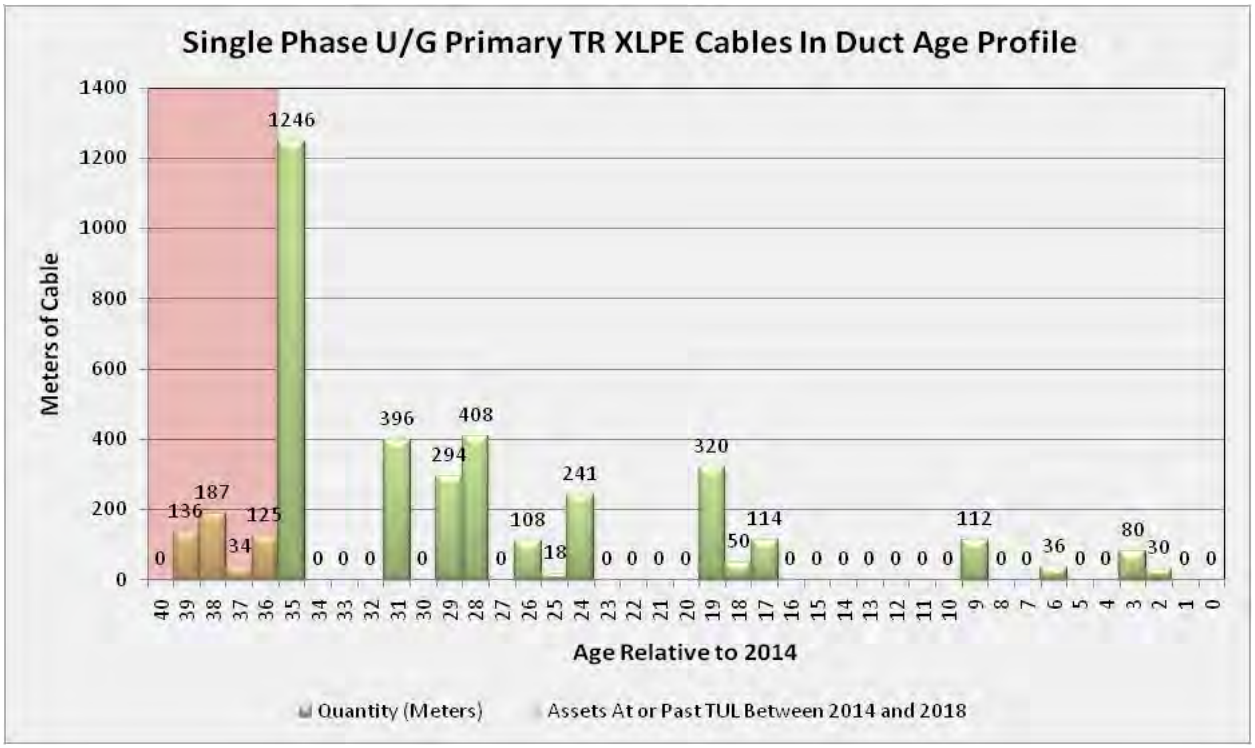
FFPC has adopted the TUL of 40 years as per the "Kinectrics Report". FFPC has divided the conductor runs into Single Phase, Two Phase and Three Phase Circuits and lastly into Overall Conductor Length. The following tables and graphs illustrate the age distribution of Single Phase, Two Phase, Three Phase Circuits, as well as Overall Conductor Length with respect to a TUL of 40 years.

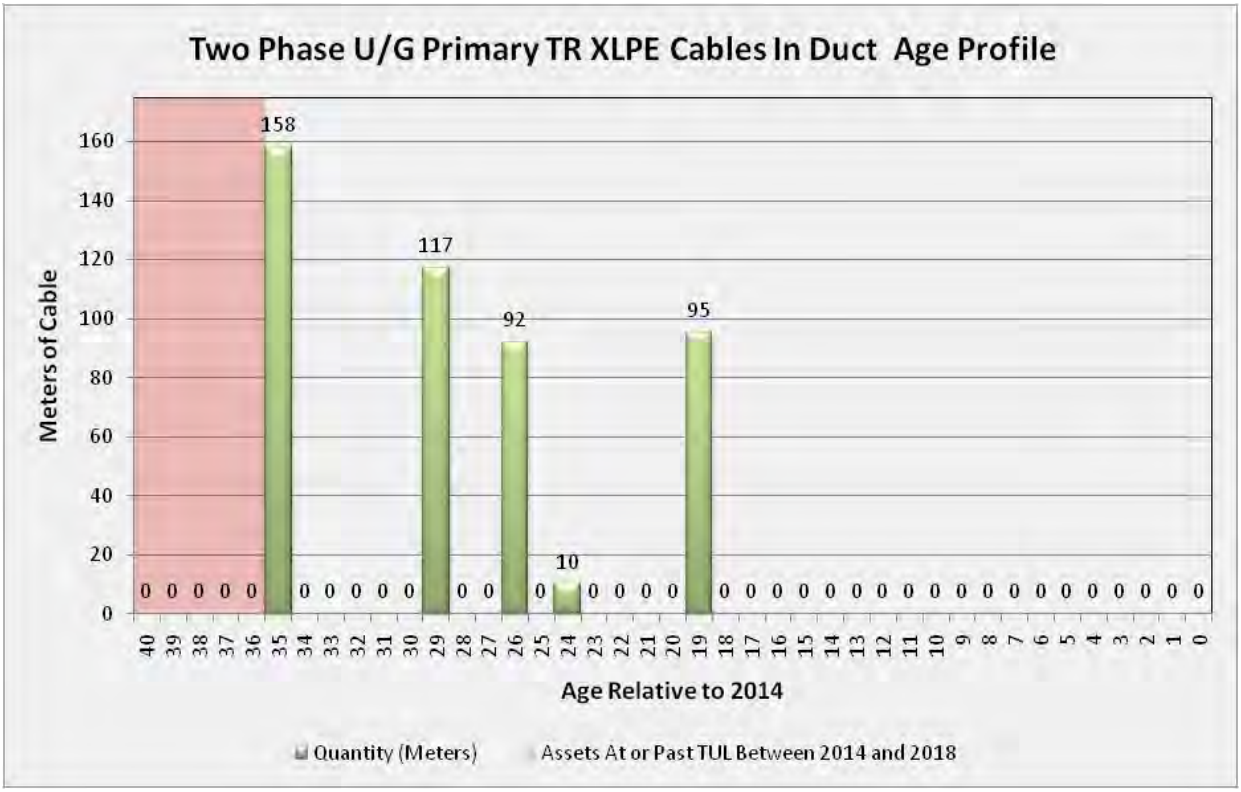
Single Phase U/G Primary TR XLPE Cables In Duct Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 40 Year TUL)**	**Quantity (Meters)**
1974	**40**	**2014**	**0**
1975	**39**	**2015**	**136**
1976	**38**	**2016**	**187**
1977	**37**	**2017**	**34**
1978	**36**	**2018**	**125**
1979	35	2019	1,246
1980	34	2020	0
1981	33	2021	0
1982	32	2022	0
1983	31	2023	396
1984	30	2024	0
1985	29	2025	294
1986	28	2026	408
1987	27	2027	0
1988	26	2028	108
1989	25	2029	18
1990	24	2030	241
1991	23	2031	0
1992	22	2032	0
1993	21	2033	0
1994	20	2034	0
1995	19	2035	320
1996	18	2036	50
1997	17	2037	114
1998	16	2038	0
1999	15	2039	0
2000	14	2040	0
2001	13	2041	0
2002	12	2042	0
2003	11	2043	0
2004	10	2044	0
2005	9	2045	112
2006	8	2046	0
2007	7	2047	0
2008	6	2048	36
2009	5	2049	0
2010	4	2050	0
2011	3	2051	80
2012	2	2052	30
2013	1	2053	0
2014	0	2054	0
Total			**3,935.8**

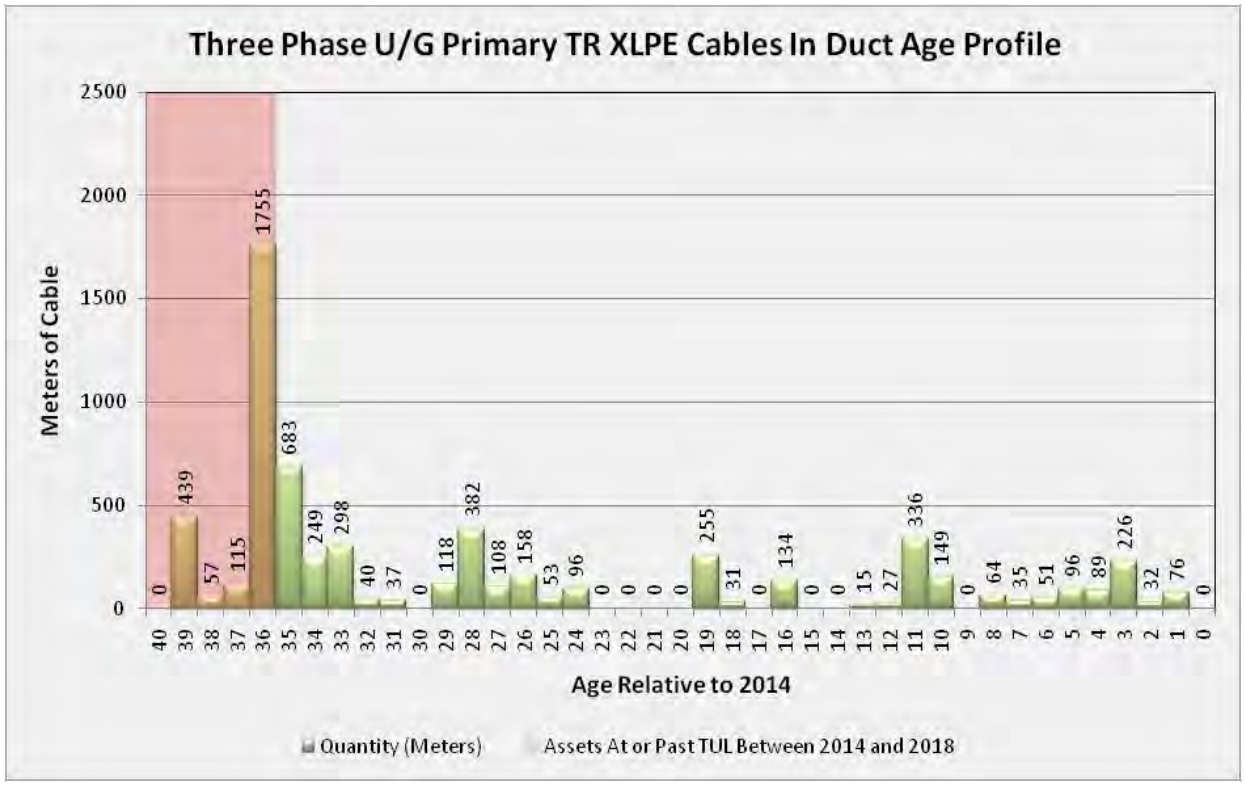
Two Phase U/G Primary TR XLPE Cables In Duct Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 40 Year TUL)**	**Quantity (Meters)**
1974	**40**	**2014**	**0**
1975	**39**	**2015**	**0**
1976	**38**	**2016**	**0**
1977	**37**	**2017**	**0**
1978	**36**	**2018**	**0**
1979	35	2019	158
1980	34	2020	0
1981	33	2021	0
1982	32	2022	0
1983	31	2023	0
1984	30	2024	0
1985	29	2025	117
1986	28	2026	0
1987	27	2027	0
1988	26	2028	92
1989	25	2029	0
1990	24	2030	10
1991	23	2031	0
1992	22	2032	0
1993	21	2033	0
1994	20	2034	0
1995	19	2035	95
1996	18	2036	0
1997	17	2037	0
1998	16	2038	0
1999	15	2039	0
2000	14	2040	0
2001	13	2041	0
2002	12	2042	0
2003	11	2043	0
2004	10	2044	0
2005	9	2045	0
2006	8	2046	0
2007	7	2047	0
2008	6	2048	0
2009	5	2049	0
2010	4	2050	0
2011	3	2051	0
2012	2	2052	0
2013	1	2053	0
2014	0	2054	0
Total			**472.0**

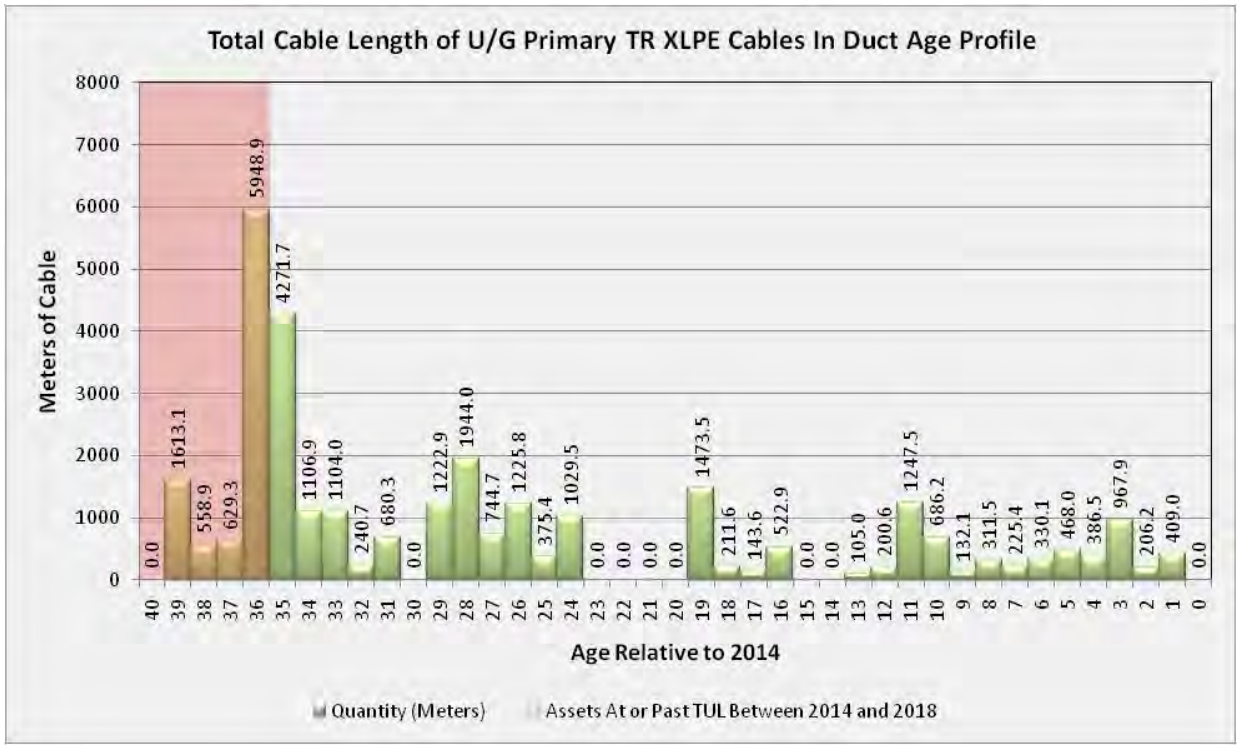
Three Phase U/G Primary TR XLPE Cables In Duct Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 40 Year TUL)**	**Quantity (Meters)**
1974	**40**	**2014**	**0**
1975	**39**	**2015**	**439**
1976	**38**	**2016**	**57**
1977	**37**	**2017**	**115**
1978	**36**	**2018**	**1755**
1979	35	2019	683
1980	34	2020	249
1981	33	2021	298
1982	32	2022	40
1983	31	2023	37
1984	30	2024	0
1985	29	2025	118
1986	28	2026	382
1987	27	2027	108
1988	26	2028	158
1989	25	2029	53
1990	24	2030	96
1991	23	2031	0
1992	22	2032	0
1993	21	2033	0
1994	20	2034	0
1995	19	2035	255
1996	18	2036	31
1997	17	2037	0
1998	16	2038	134
1999	15	2039	0
2000	14	2040	0
2001	13	2041	15
2002	12	2042	27
2003	11	2043	336
2004	10	2044	149
2005	9	2045	0
2006	8	2046	64
2007	7	2047	35
2008	6	2048	51
2009	5	2049	96
2010	4	2050	89
2011	3	2051	226
2012	2	2052	32
2013	1	2053	76
2014	0	2054	0
Total			**6,204.0**

Total Cable Length of U/G Primary TR XLPE Cables In Duct Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 40 Year TUL)**	**Quantity (Meters)**
1974	40	2014	0.0
1975	39	2015	1613.1
1976	38	2016	558.9
1977	37	2017	629.3
1978	36	2018	5948.9
1979	35	2019	4271.7
1980	34	2020	1106.9
1981	33	2021	1104.0
1982	32	2022	240.7
1983	31	2023	680.3
1984	30	2024	0.0
1985	29	2025	1222.9
1986	28	2026	1944.0
1987	27	2027	744.7
1988	26	2028	1225.8
1989	25	2029	375.4
1990	24	2030	1029.5
1991	23	2031	0.0
1992	22	2032	0.0
1993	21	2033	0.0
1994	20	2034	0.0
1995	19	2035	1473.5
1996	18	2036	211.6
1997	17	2037	143.6
1998	16	2038	522.9
1999	15	2039	0.0
2000	14	2040	0.0
2001	13	2041	105.0
2002	12	2042	200.6
2003	11	2043	1247.5
2004	10	2044	686.2
2005	9	2045	132.1
2006	8	2046	311.5
2007	7	2047	225.4
2008	6	2048	330.1
2009	5	2049	468.0
2010	4	2050	386.5
2011	3	2051	967.9
2012	2	2052	206.2
2013	1	2053	409.0
2014	0	2054	0.0
Total			**30,724.0**


Single Phase U/G Primary TR XLPE Cables In Duct Age Profile
Meters of Cable
1400
1200
1000
800
600
400
200
0
1246
396
408
294
320
241
187
136
125
114
112
108
80
50
36
34
30
18
Age Relative to 2014
Quantity (Meters)
Assets At or Past TUL Between 2014 and 2018


Two Phase U/G Primary TR XLPE Cables In Duct Age Profile
Meters of Cable
160
140
120
100
80
60
40
20
0
158
117
92
95
10
Age Relative to 2014
Quantity (Meters)
Assets At or Past TUL Between 2014 and 2018


Three Phase U/G Primary TR XLPE Cables In Duct Age Profile
Meters of Cable
2500
2000
1500
1000
500
0
0 439 57 115 1755 683 249 298 40 37 0 118 382 108 158 53 96 0 0 0 0 255 31 0 134 0 0 0 15 27 336 149 0 64 35 51 96 89 226 32 76 0
40 39 38 37 36 35 34 33 32 31 30 29 28 27 26 25 24 23 22 21 20 19 18 17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1 0
Age Relative to 2014
Quantity (Meters)
Assets At or Past TUL Between 2014 and 2018


Total Cable Length of U/G Primary TR XLPE Cables In Duct Age Profile
Meters of Cable
8000
7000
6000
5000
4000
3000
2000
1000
0
0.0 1613.1 558.9 629.3 5948.9 4271.7 1106.9 1104.0 240.7 680.3 0.0 1222.9 1944.0 744.7 1225.8 375.4 1029.5 0.0 0.0 0.0 0.0 1473.5 211.6 143.6 522.9 0.0 0.0 105.0 200.6 1247.5 686.2 132.1 311.5 225.4 330.1 468.0 386.5 967.9 206.2 409.0 0.0
40 39 38 37 36 35 34 33 32 31 30 29 28 27 26 25 24 23 22 21 20 19 18 17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1 0
Age Relative to 2014
Quantity (Meters)
Assets At or Past TUL Between 2014 and 2018

5.3.2.2.f.iv.2 Primary TR XLPE Cables in Duct Adjusted End-of-Life Projections

FFPC has divided its underground cables into Single Phase, Two Phase and Three Phase Circuit groupings, as well as by Total Conductor Length for planning considerations. FFPC performs inspections and condition assessments on the portions of TR XLPE cables that are exposed above ground and are accessible via cable vaults, or pad-mounted transformer enclosures. The inspection and condition assessments are part of FFPC's maintenance inspection program which is conducted annually. The inspections and condition assessments are currently limited to identifying problems with cable terminations, which are a known common point of failure. The inspection process has identified close to a dozen sets of cable terminations over the last two years, which were close to failure due to extensive degradation (burning from moisture and contamination).

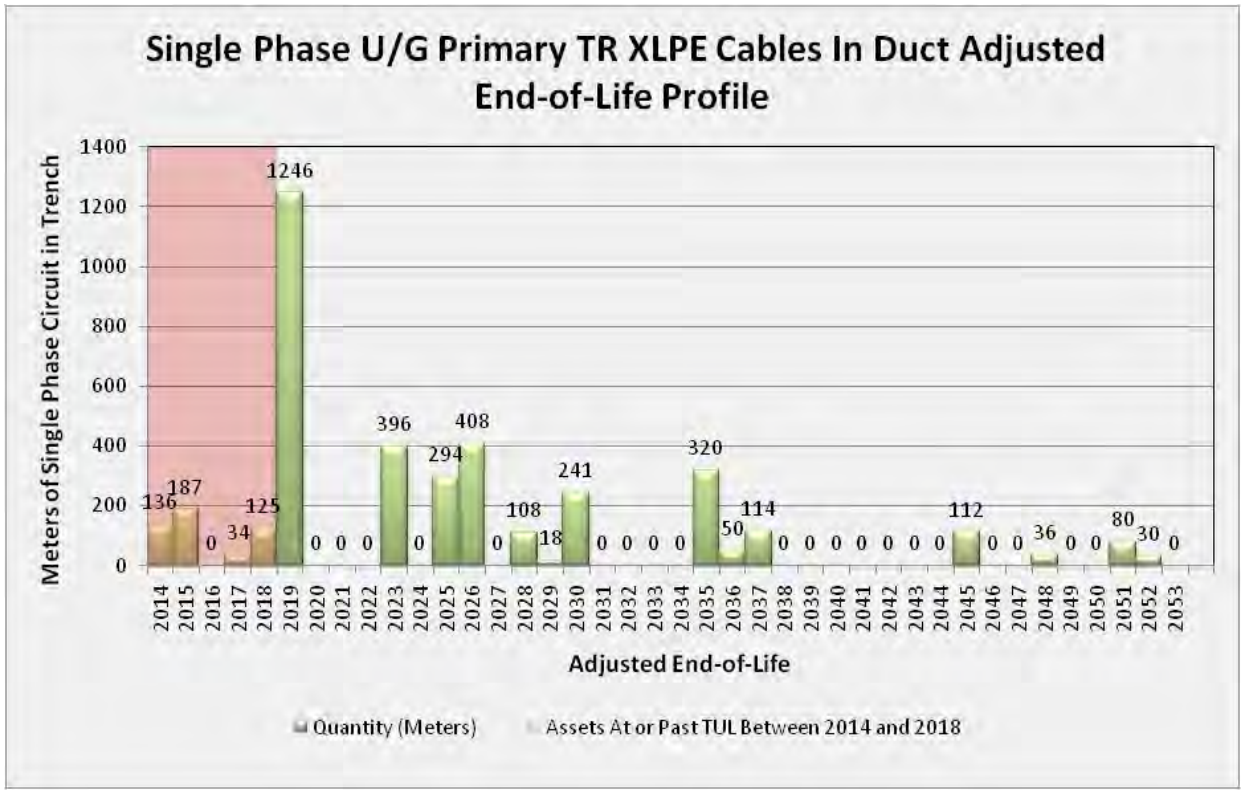
As the underground portions of cable runs are not conducive to visual inspection, FFPC is currently evaluating several service providers who perform analytical condition testing (determine cable insulation degradation profile,) as well as who offer cable rejuvenation services. A common rejuvenation technique is silicone injection. As per FFPC's asset management process, adjusted end-of-life values are assigned to cables according to the results of inspections and condition tests. FFPC's adjusted end-of-life projections will be updated once the analytical testing has been completed. A large portion of FFPC's underground cables are approaching their UL of 40 years throughout the 2014 to 2018 planning period, and as such will demand either rejuvenation or replacement. The following table and graph illustrate the adjusted end-of-life profile for FFPC's TR XLPE Cables in Duct.

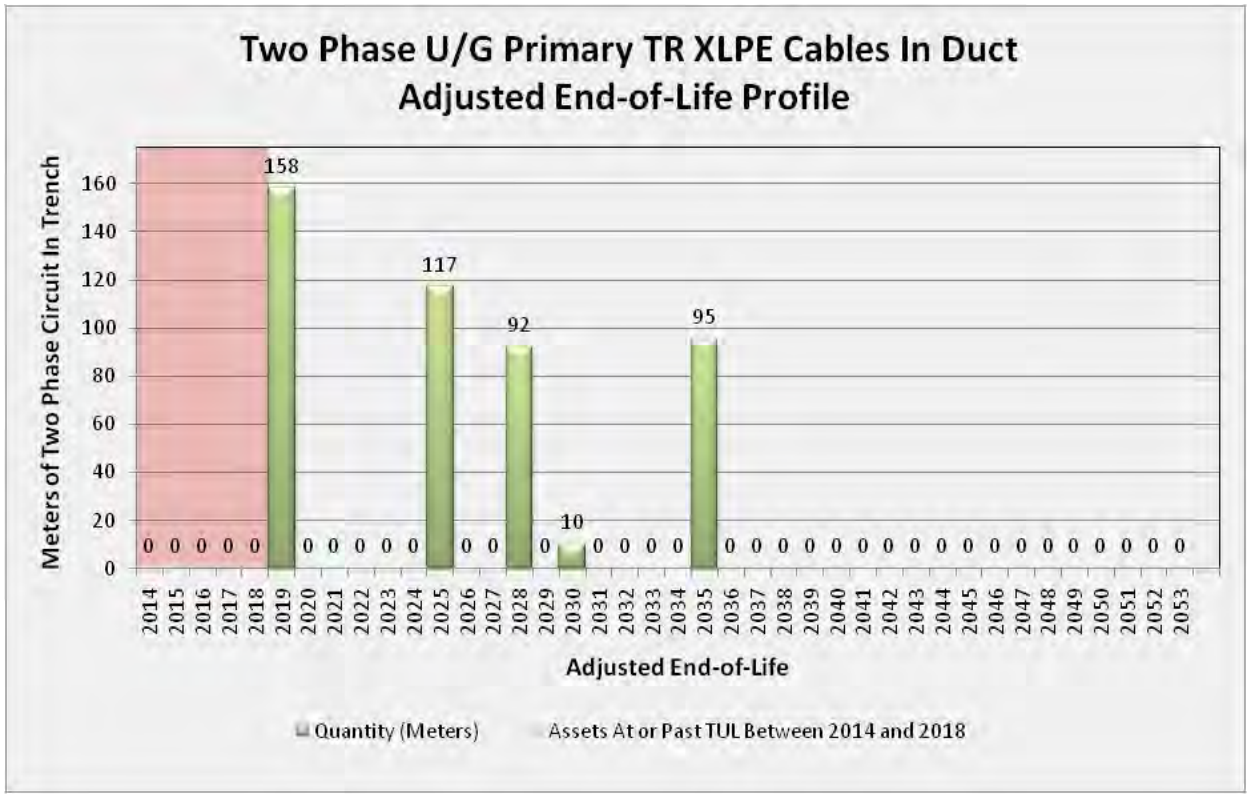
Single Phase U/G Primary TR XLPE Cables In Duct Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity (Meters)**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**136**	**$ 6,240.39**	**98.396**
2	**2015**	**187**	**$ 8,609.27**	**98.396**
3	**2016**	**0**	**$ -**	**98.396**
4	**2017**	**34**	**$ 1,576.28**	**98.396**
5	**2018**	**125**	**$ 5,740.67**	**98.396**
6	2019	1246	$ 57,271.25	98.396
7	2020	0	$ -	98.396
8	2021	0	$ -	98.396
9	2022	0	$ -	98.396
10	2023	396	$ 18,214.88	98.396
11	2024	0	$ -	98.396
12	2025	294	$ 13,518.59	98.396
13	2026	408	$ 18,743.90	98.396
14	2027	0	$ -	98.396
15	2028	108	$ 4,972.52	98.396
16	2029	18	$ 813.45	98.396
17	2030	241	$ 11,088.37	98.396
18	2031	0	$ -	98.396
19	2032	0	$ -	98.396
20	2033	0	$ -	98.396
21	2034	0	$ -	98.396
22	2035	320	$ 14,705.66	98.396
23	2036	50	$ 2,298.00	98.396
24	2037	114	$ 5,221.49	98.396
25	2038	0	$ -	98.396
26	2039	0	$ -	98.396
27	2040	0	$ -	98.396
28	2041	0	$ -	98.396
29	2042	0	$ -	98.396
30	2043	0	$ -	98.396
31	2044	0	$ -	98.396
32	2045	112	$ 5,153.26	98.396
33	2046	0	$ -	98.396
34	2047	0	$ -	98.396
35	2048	36	$ 1,648.25	98.396
36	2049	0	$ -	98.396
37	2050	0	$ -	98.396
38	2051	80	$ 3,676.80	98.396
39	2052	30	$ 1,397.43	98.396
40	2053	0	$ -	98.396
Totals		**3935.8**	**$ 180,890.45**	**3935.8**

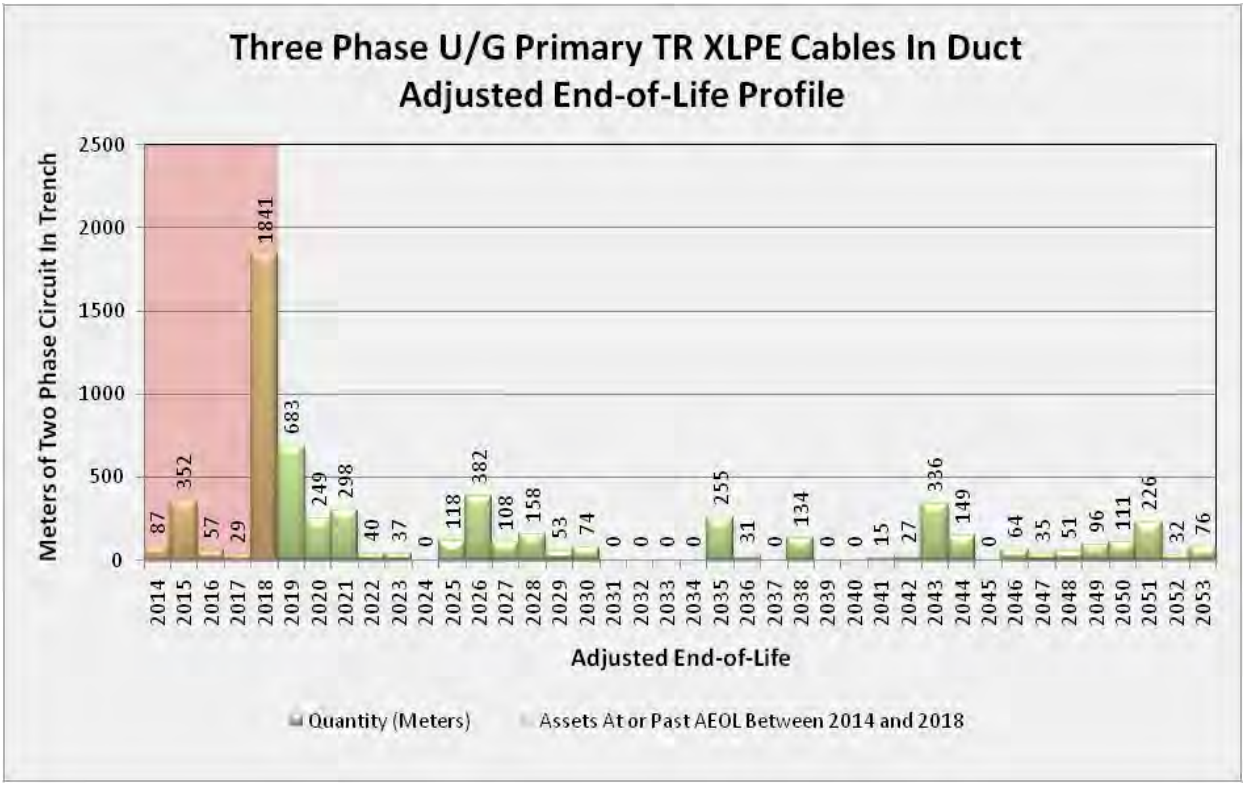
Two Phase U/G Primary TR XLPE Cables In Duct Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity (Meters)**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**0**	**$ -**	**11.800**
2	**2015**	**0**	**$ -**	**11.800**
3	**2016**	**0**	**$ -**	**11.800**
4	**2017**	**0**	**$ -**	**11.800**
5	**2018**	**0**	**$ -**	**11.800**
6	2019	158	$ 12,707.94	11.800
7	2020	0	$ -	11.800
8	2021	0	$ -	11.800
9	2022	0	$ -	11.800
10	2023	0	$ -	11.800
11	2024	0	$ -	11.800
12	2025	117	$ 9,410.31	11.800
13	2026	0	$ -	11.800
14	2027	0	$ -	11.800
15	2028	92	$ 7,399.56	11.800
16	2029	0	$ -	11.800
17	2030	10	$ 804.30	11.800
18	2031	0	$ -	11.800
19	2032	0	$ -	11.800
20	2033	0	$ -	11.800
21	2034	0	$ -	11.800
22	2035	95	$ 7,640.85	11.800
23	2036	0	$ -	11.800
24	2037	0	$ -	11.800
25	2038	0	$ -	11.800
26	2039	0	$ -	11.800
27	2040	0	$ -	11.800
28	2041	0	$ -	11.800
29	2042	0	$ -	11.800
30	2043	0	$ -	11.800
31	2044	0	$ -	11.800
32	2045	0	$ -	11.800
33	2046	0	$ -	11.800
34	2047	0	$ -	11.800
35	2048	0	$ -	11.800
36	2049	0	$ -	11.800
37	2050	0	$ -	11.800
38	2051	0	$ -	11.800
39	2052	0	$ -	11.800
40	2053	0	$ -	11.800
Totals		**472.0**	**$ 37,962.96**	**472.0**

Three Phase U/G Primary TR XLPE Cables In Duct Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	Adjusted End-of-Life Year	Quantity (Meters)	Replacement Cost	Ideal Evenly Distributed Annual Replacement Rate
1	**2014**	**87**	**$ 10,010.17**	**155.1**
2	**2015**	**352**	**$ 40,444.80**	**155.1**
3	**2016**	**57**	**$ 6,573.05**	**155.1**
4	**2017**	**29**	**$ 3,338.68**	**155.1**
5	**2018**	**1841**	**$ 211,486.36**	**155.1**
6	2019	683	$ 78,501.15	155.1
7	2020	249	$ 28,606.84	155.1
8	2021	298	$ 34,239.04	155.1
9	2022	40	$ 4,624.42	155.1
10	2023	37	$ 4,284.99	155.1
11	2024	0	$ -	155.1
12	2025	118	$ 13,587.29	155.1
13	2026	382	$ 43,899.04	155.1
14	2027	108	$ 12,437.64	155.1
15	2028	158	$ 18,140.77	155.1
16	2029	53	$ 6,040.81	155.1
17	2030	74	$ 8,512.57	155.1
18	2031	0	$ -	155.1
19	2032	0	$ -	155.1
20	2033	0	$ -	155.1
21	2034	0	$ -	155.1
22	2035	255	$ 29,242.58	155.1
23	2036	31	$ 3,506.88	155.1
24	2037	0	$ -	155.1
25	2038	134	$ 15,431.84	155.1
26	2039	0	$ -	155.1
27	2040	0	$ -	155.1
28	2041	15	$ 1,723.50	155.1
29	2042	27	$ 3,086.54	155.1
30	2043	336	$ 38,588.26	155.1
31	2044	149	$ 17,088.07	155.1
32	2045	0	$ -	155.1
33	2046	64	$ 7,335.22	155.1
34	2047	35	$ 4,037.17	155.1
35	2048	51	$ 5,908.16	155.1
36	2049	96	$ 11,030.40	155.1
37	2050	111	$ 12,734.24	155.1
38	2051	226	$ 25,965.36	155.1
39	2052	32	$ 3,667.05	155.1
40	2053	76	$ 8,768.84	155.1
Totals		**6204.0**	**$ 712,841.75**	**6204.0**

Total Cable Length UG Primary TR XLPE Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity (Meters)**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**497**	**$ 16,250.56**	**768.1**
2	**2015**	**1323**	**$ 49,054.07**	**768.1**
3	**2016**	**352**	**$ 6,573.05**	**768.1**
4	**2017**	**281**	**$ 4,914.97**	**768.1**
5	**2018**	**6297**	**$ 217,227.03**	**768.1**
6	2019	4272	$ 148,480.34	768.1
7	2020	1107	$ 28,606.84	768.1
8	2021	1104	$ 34,239.04	768.1
9	2022	241	$ 4,624.42	768.1
10	2023	680	$ 22,499.88	768.1
11	2024	0	$ -	768.1
12	2025	1223	$ 36,516.19	768.1
13	2026	1944	$ 62,642.94	768.1
14	2027	745	$ 12,437.64	768.1
15	2028	1226	$ 30,512.86	768.1
16	2029	375	$ 6,854.26	768.1
17	2030	904	$ 20,405.24	768.1
18	2031	0	$ -	768.1
19	2032	0	$ -	768.1
20	2033	0	$ -	768.1
21	2034	0	$ -	768.1
22	2035	1473	$ 51,589.09	768.1
23	2036	212	$ 5,804.88	768.1
24	2037	144	$ 5,221.49	768.1
25	2038	523	$ 15,431.84	768.1
26	2039	0	$ -	768.1
27	2040	0	$ -	768.1
28	2041	105	$ 1,723.50	768.1
29	2042	201	$ 3,086.54	768.1
30	2043	1248	$ 38,588.26	768.1
31	2044	686	$ 17,088.07	768.1
32	2045	132	$ 5,153.26	768.1
33	2046	312	$ 7,335.22	768.1
34	2047	225	$ 4,037.17	768.1
35	2048	330	$ 7,556.41	768.1
36	2049	468	$ 11,030.40	768.1
37	2050	512	$ 12,734.24	768.1
38	2051	968	$ 29,642.16	768.1
39	2052	206	$ 5,064.48	768.1
40	2053	409	$ 8,768.84	768.1
Total		**30724.0**	**$ 931,695.17**	**30724.0**


Single Phase U/G Primary TR XLPE Cables In Duct Adjusted End-of-Life Profile
Meters of Single Phase Circuit in Trench
Adjusted End-of-Life
Quantity (Meters)
Assets At or Past TUL Between 2014 and 2018


Two Phase U/G Primary TR XLPE Cables In Duct Adjusted End-of-Life Profile
Meters of Two Phase Circuit In Trench
Adjusted End-of-Life
Quantity (Meters)
Assets At or Past TUL Between 2014 and 2018


Three Phase U/G Primary TR XLPE Cables In Duct
Adjusted End-of-Life Profile
Meters of Two Phase Circuit In Trench
2500
2000
1500
1000
500
0
87
352
57
29
1841
683
249
298
40
37
0
118
382
108
158
53
74
0
0
0
0
255
31
0
134
0
0
15
27
336
149
0
64
35
51
96
111
226
32
76
2014
2015
2016
2017
2018
2019
2020
2021
2022
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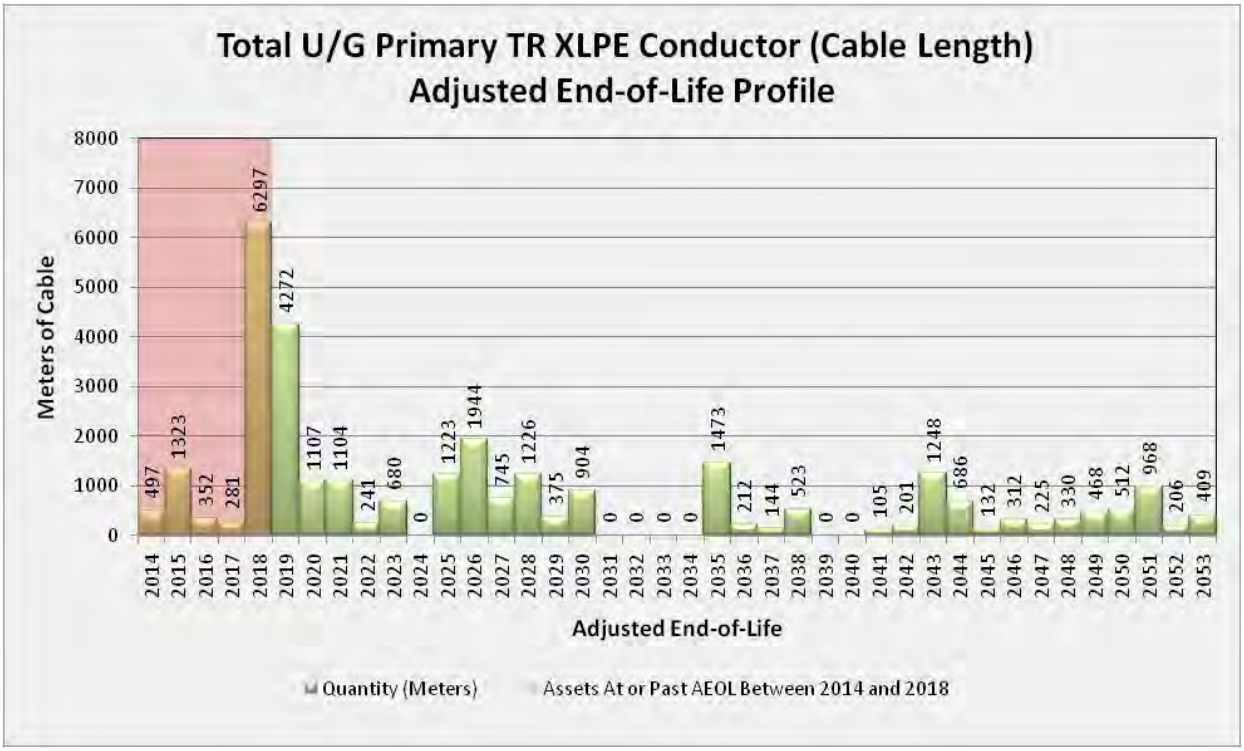
2043
2044
2045
2046
2047
2048
2049
2050
2051
2052
2053
Adjusted End-of-Life
Quantity (Meters)
Assets At or Past AEOL Between 2014 and 2018


Total U/G Primary TR XLPE Conductor (Cable Length)
Adjusted End-of-Life Profile
Meters of Cable
8000
7000
6000
5000
4000
3000
2000
1000
0
497
1323
352
281
6297
4272
1107
1104
241
680
0
1223
1944
745
1226
375
904
0
0
0
0
1473
212
144
523
0
0
105
201
1248
686
132
312
225
330
468
512
968
206
409
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
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2042
2043
2044
2045
2046
2047
2048
2049
2050
2051
2052
2053
Adjusted End-of-Life
Quantity (Meters)
Assets At or Past AEOL Between 2014 and 2018

5.3.2.2.f.iv.3 Lifecycle Analysis Summary & Budget Allocation

Total Cable Length of U/G Primary TR XLPE Cables In Duct Profile			
30724	Quantity (Meters)	412	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL	8750	Quantity Reaching Adjusted End of Life Over Forecast Period
27.1	Average Age of Population	$294,020	Total Capital Replacement Cost over Forecast Period
768.10	Ideal Equalized Annual Replacement Rate (Meters/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
67.7%	% UL Consumed	1750.06	Average Replacements Per Year
80.2%	2019 % UL Consumed with no Reinvestment	$58,804	Average Annual Cost Per Year
		$23,292	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$80,537	2014 - 2018 Total Allocated Capital Replacement Amount
		$100,000	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 30.7 km of Primary TR XLPE Cables in Duct, are not evenly distributed over one lifecycle period beginning in 2014. The population has a high positive skew, and as such, approximately 74% (22.7 km) will require replacement over the first half of the lifecycle period (over the next 20 years). FFPC adopted a UL of 40 years, and based on the average age of 27.1 years for the population, 67.7% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 80.2% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced or installed an average of 0.4 km of primary TR XLPE cables in duct per year, which is significantly lower than the ideal average annual replacement rate of 0.8 km per year. Over the 2014 to 2018 forecast period, an estimated 8.7 km of cables will reach or surpass their AEOL, requiring replacement or refurbishment. The total estimated capital replacement cost is $294,020. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $23,292 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated a total of $52,537 towards the replacement of 1.9 km of short cable runs and a total of $128,000 towards the refurbishment of 6.8 km of long cable runs. The average annual replacement rate is projected to be 0.38 km per year, with an average annual replacement cost of $10,507. The average annual refurbishment rate is projected to be 1.36 km per year, with an average annual refurbishment cost of $25,600 per year. FFPC has allocated a total of $180,537 towards capital replacements and refurbishments over the 2014 to 2018 planning period, which equates to average annual reinvestments of $36,107. This is approximately 55% higher than the ideal average annual reinvestment need, due to the large quantify of projected cable failures, as illustrated by the large positive skew on the age profile.

5.3.2.2.f.iv.4 Impact of Primary TR XLPE Cables in Duct on DS Plan

The planned reinvestment into Primary TR XLPE Cables in Duct has a significant impact on FFPC's DS Plan. The combined total capital replacement and refurbishment cost of $180,537 for the cables represents 5.1% of the total planned capital expenditures over the 2014 to 2018 planning horizon.

5.3.2.2.f.v. Secondary Cables Direct Buried

FFPC has not yet mapped or recorded the dimension of individual underground secondary cable runs. The mapping and collection of this dimensional data will be completed over the next several years, as part of FFPC's GIS expansion effort. FFPC estimates that approximately 5% of its customer base utilizes underground services, and that the average service length is 20 meters. As such, FFPC estimates that it has approximately 3.8 km of direct buried secondary cables (at the time FFPC estimated having 3830 customers). Direct buried secondary cables are mostly found in newer subdivisions throughout the community.

5.3.2.2.f.v.1 Secondary Cables Direct Buried Age Profile Relative to TUL

FFPC performs inspections and condition assessments on the portions of direct buried secondary cables that are exposed above ground and are accessible via cable vaults or pad-mounted transformer enclosures. The inspection and condition assessments are part of FFPC's maintenance inspection program, which is conducted annually. FFPC has adopted a TUL of 35 years for direct buried secondary cables, as per the "Kinectrics Report". The age profile of individual secondary cables direct buried is not known at this time. The overall useful remaining life of this asset class is estimated to be 28%.

5.3.2.2.f.v.2 Secondary Cables Direct Buried Adjusted End-of-Life Projections

Adjusted End-of-Life projections are unavailable at this time.

5.3.2.2.f.v.3 Lifecycle Analysis Summary & Budget Allocation

To date, FFPC does not have complete age profile data set available for secondary cables direct buried. FFPC will rely on inspection findings for identifying cables that are near the end of their useful service life. The total average annual reinvestment need for this asset class, as established by the asset management process, is $1,953. The annual reinvestment need is based on the total cost to replace the asset class divided by the period established by the UL that FFPC adopted ($68,366 / 35 years). FFPC has allocated a total of $10,000 for capital cable replacements over the planning horizon, which equates to a total annual reinvestment of $2,000. FFPC's strategy is to complete gathering age profile, dimension and condition data, and once it has been obtained to revise reinvestment needs accordingly.

5.3.2.2.f.v.4 Impact of Secondary Cables Direct Buried on DS Plan

The overall impact of this asset class on FFPC's DS Plan is very small. FFPC has allocated a total of $10,000 towards direct buried cable replacements over the planning horizon, which represents approximately 0.28% of all planned capital expenditures. FFPC plans on intensifying replacements over the 2019 to 2023 planning horizon, at which time individual cable runs will be better understood.

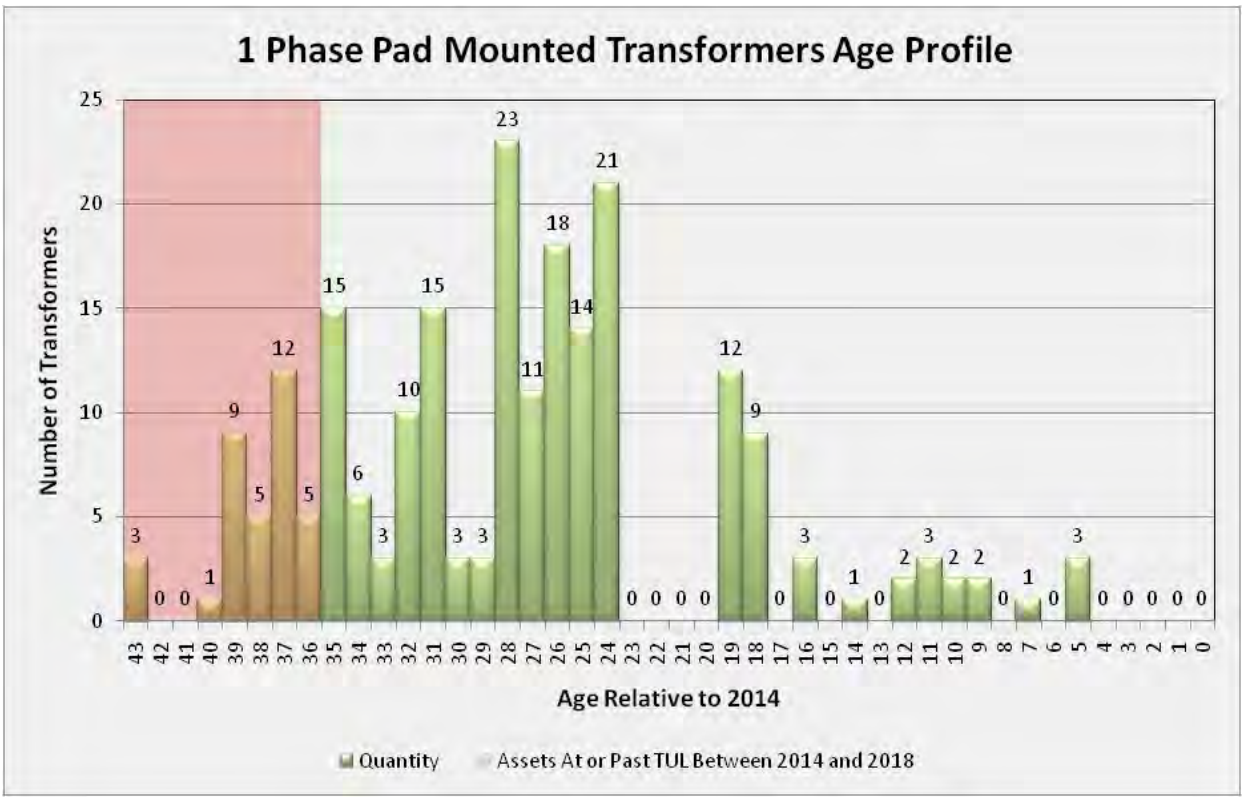
5.3.2.2.f.vi. Pad-Mounted Transformers

Pad-mounted transformers represent a significant portion of FFPC's overall asset base with respect to replacement cost. As previously mentioned, FFPC performed a distribution system wide voltage conversion and rebuild, over a relatively small window of time. As such, a significant portion of FFPC's pad-mounted transformers are of the same vintage. FFPC will experience somewhat of a "tidal wave" affect in the near future as these assets approach their UL of 40 years. FFPC has divided its pad-mounted transformer fleet into Three Phase and Single Phase classes. FFPC currently owns and operates 215 single phase and 38 three phase pad-mounted transformers.

5.3.2.2.f.vi.1 Single Phase Pad-Mounted Transformers Age Profile Relative to TUL

The following table and graph represent the age profile of FFPC's single phase pad-mounted transformers with respect to a TUL of 40 years.

Single Phase Pad-Mounted Transformers Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	Age	End-of-Life (Based on 40 Year TUL)	Quantity
1971	**43**	**2011**	**3**
1972	**42**	**2012**	**0**
1973	**41**	**2013**	**0**
1974	**40**	**2014**	**1**
1975	**39**	**2015**	**9**
1976	**38**	**2016**	**5**
1977	**37**	**2017**	**12**
1978	**36**	**2018**	**5**
1979	35	2019	15
1980	34	2020	6
1981	33	2021	3
1982	32	2022	10
1983	31	2023	15
1984	30	2024	3
1985	29	2025	3
1986	28	2026	23
1987	27	2027	11
1988	26	2028	18
1989	25	2029	14
1990	24	2030	21
1991	23	2031	0
1992	22	2032	0
1993	21	2033	0
1994	20	2034	0
1995	19	2035	12
1996	18	2036	9
1997	17	2037	0
1998	16	2038	3
1999	15	2039	0
2000	14	2040	1
2001	13	2041	0
2002	12	2042	2
2003	11	2043	3
2004	10	2044	2
2005	9	2045	2
2006	8	2046	0
2007	7	2047	1
2008	6	2048	0
2009	5	2049	3
2010	4	2050	0
2011	3	2051	0
2012	2	2052	0
2013	1	2053	0
2014	0	2054	0
Total			**215**

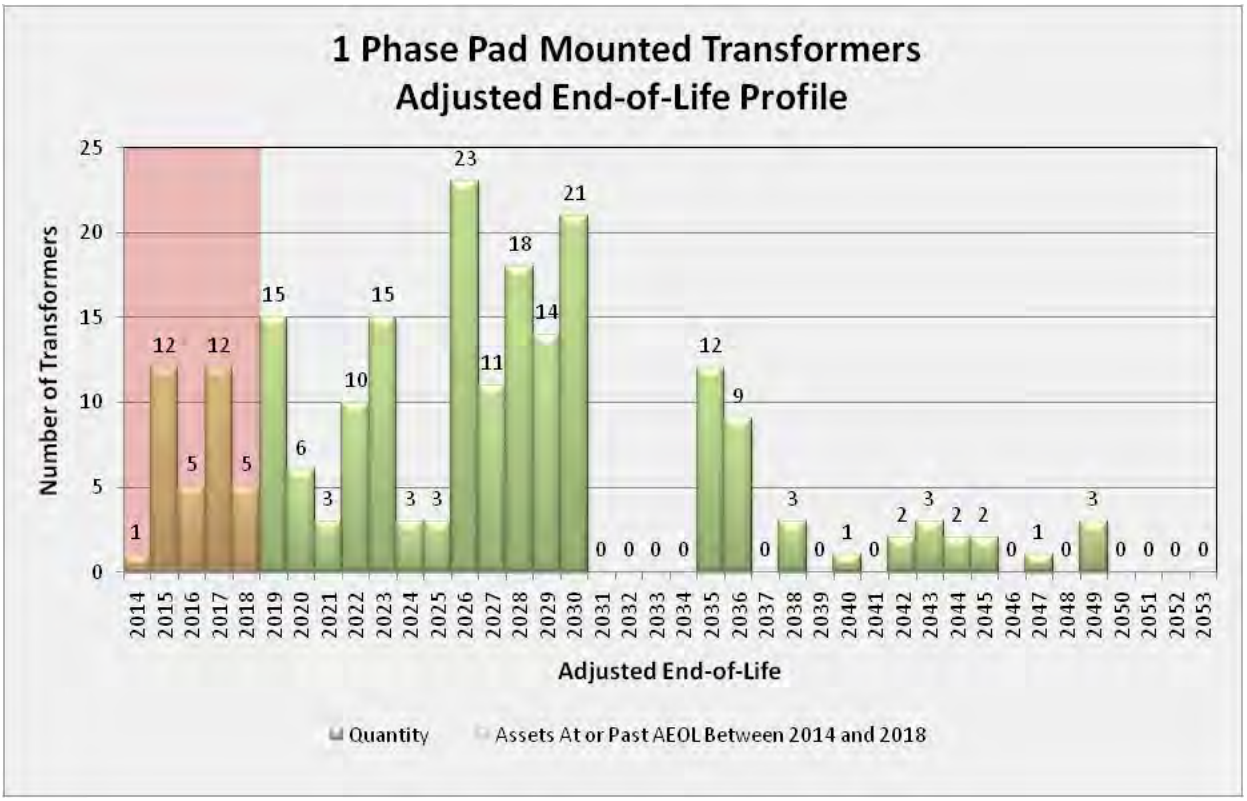


5.3.2.2.f.vi.2 Single Phase Pad-Mounted Transformers Adjusted End-of-Life Projections

FFPC performs detailed inspections of pad-mounted transformers on an annual basis. The results of the inspections are used to assess the overall health of transformers with respect to age. Physical defects such as oil leaks or cracked bushing indicate that a transformer is very near to the end of its useful service life, having a high probability of failure. FFPC has assigned adjusted end-of-life dates to individual transformers using FFPC's asset management process. It is important to note that the adjusted end-of-life values are of higher importance as assets approach their TUL, as opposed to during their earlier years.

FFPC is also currently working on recording the relationship of transformers to customers, which will allow for analysis of electrical loading from smart meter data. Smart meter data will essentially give FFPC insight into individual transformer utilization (loading). Electrical loading is a large contributor to transformer degradation, and as such, being able to quantify it will greatly enhance FFPC's ability of accurately predicting transformer failures. The following table and graph illustrate the adjusted end-of-life profile for FFPC's Single Phase Pad-Mounted Transformer fleet, based on the most recent inspection results.

Single Phase Pad-Mounted Transformers Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**1**	**$ 11,036.02**	**5.375**
2	**2015**	**12**	**$ 135,682.24**	**5.375**
3	**2016**	**5**	**$ 49,680.10**	**5.375**
4	**2017**	**12**	**$ 123,932.24**	**5.375**
5	**2018**	**5**	**$ 48,430.10**	**5.375**
6	2019	15	$ 146,679.28	5.375
7	2020	6	$ 63,216.12	5.375
8	2021	3	$ 31,608.06	5.375
9	2022	10	$ 102,110.20	5.375
10	2023	15	$ 155,040.30	5.375
11	2024	3	$ 30,108.06	5.375
12	2025	3	$ 31,108.06	5.375
13	2026	23	$ 235,828.46	5.375
14	2027	11	$ 109,896.22	5.375
15	2028	18	$ 181,426.32	5.375
16	2029	14	$ 141,504.28	5.375
17	2030	21	$ 208,756.42	5.375
18	2031	0	$ -	5.375
19	2032	0	$ -	5.375
20	2033	0	$ -	5.375
21	2034	0	$ -	5.375
22	2035	12	$ 116,571.22	5.375
23	2036	9	$ 106,824.18	5.375
24	2037	0	$ -	5.375
25	2038	3	$ 52,608.06	5.375
26	2039	0	$ -	5.375
27	2040	1	$ 5,175.00	5.375
28	2041	0	$ -	5.375
29	2042	2	$ 20,072.04	5.375
30	2043	3	$ 34,608.06	5.375
31	2044	2	$ 22,072.04	5.375
32	2045	2	$ 19,711.02	5.375
33	2046	0	$ -	5.375
34	2047	1	$ 5,175.00	5.375
35	2048	0	$ -	5.375
36	2049	3	$ 30,108.06	5.375
37	2050	0	$ -	5.375
38	2051	0	$ -	5.375
39	2052	0	$ -	5.375
40	2053	0	$ -	5.375
Totals		**215**	**$ 2,218,967.16**	**215**



5.3.2.2.f.vi.3 Lifecycle Analysis Summary & Budget Allocation

Single Phase Pad-Mounted Transformers Profile			
215	Quantity	0.8	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL	35	Quantity Reaching Adjusted End of Life Over Forecast Period
27.7	Average Age of Population	$368,761	Total Capital Replacement Cost over Forecast Period
5.38	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
69.3%	% UL Consumed	7.00	Average Replacements Per Year
81.8%	2019 % UL Consumed with no Reinvestment	$73,752	Average Annual Cost Per Year
		$55,474	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$368,761	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 215 single phase pad-mounted transformers is not evenly distributed over one lifecycle period beginning in 2014. The population has high positive skew, and as such, approximately 82% (177 transformers) will require replacement over the first half of the lifecycle period (over the next 20 years). FFPC adopted a UL of 40 years, and based on the average age of 27.7 years for the population, 69.3% UL has been consumed. If FFPC was not to reinvest into this asset class,

the percentage of UL consumed increases to 81.8% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced an average of 0.8 single phase pad-mounted transformers per year, which is significantly lower than the ideal average annual replacement rate of 5.38 transformers per year. Over the 2014 to 2018 forecast period, an estimated 35 transformers will reach their AEOL, requiring replacement. The total estimated capital replacement cost is $368,761, which has been allocated. No capital refurbishments have been allocated as transformers are not conducive to distributor refurbishing. The average annual replacement rate is projected to be 7 transformers per year, and the average total annual reinvestment is $73,752 per year. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $55,474 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated a total of $368,761 towards capital replacements and no capital for refurbishments over the 2014 to 2018 planning period. This is approximately 33% higher than the ideal average annual reinvestment need, due to the large number of projected failures based on the large positive skew of the transformer age profile.

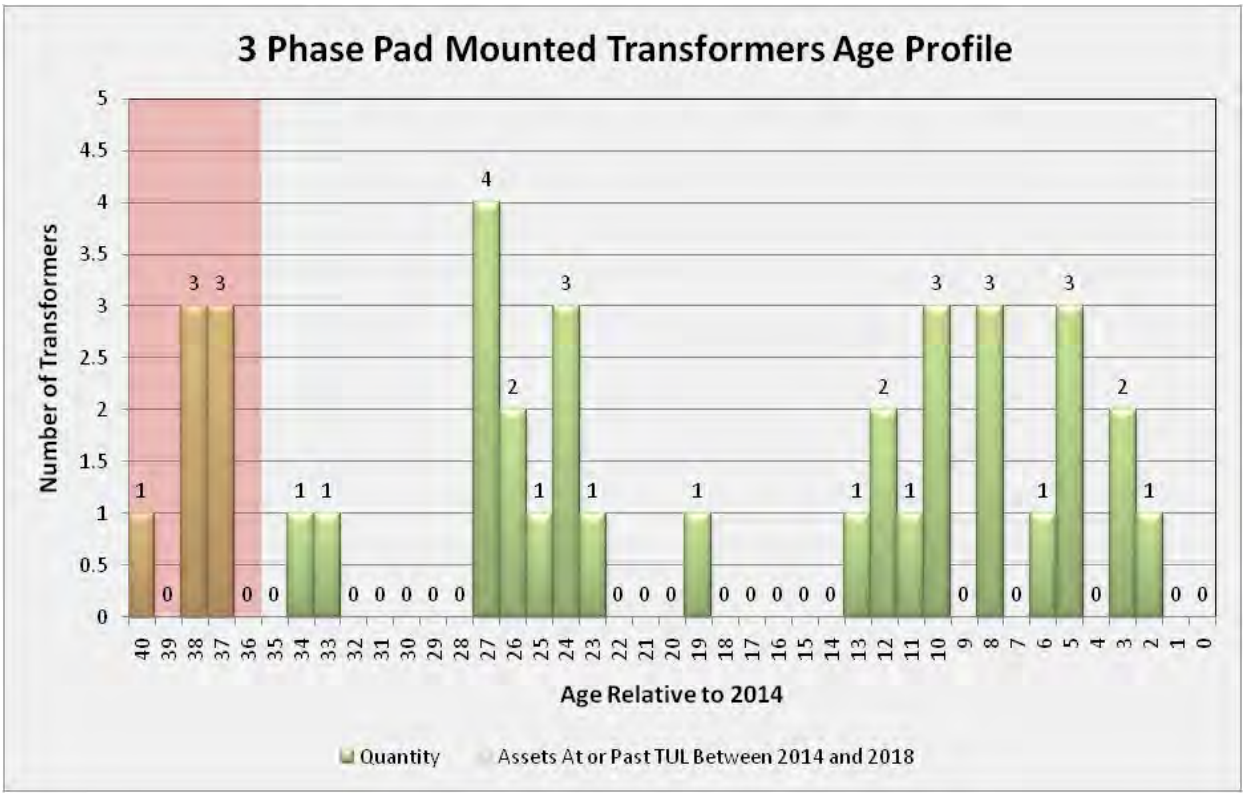
5.3.2.2.f.vi.4 Impact of Single Phase Pad-Mounted Transformers on DS Plan

The planned reinvestment into single phase pad-mounted transformers has a significant impact on FFPC's DS Plan. The total capital replacement cost of $368,761 for the transformers represents 10.5% of the total planned capital expenditures over the 2014 to 2018 planning horizon.

5.3.2.2.f.vi.5 Three Phase Pad-Mounted Transformers Age Profile Relative to TUL

The following table and graph represent the age profile of FFPC's single phase pad-mounted transformers with respect to a TUL of 40 years.

Three Phase Pad-Mounted Transformers Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 40 Year TUL)**	**Quantity**
1974	**40**	**2014**	**1**
1975	**39**	**2015**	**0**
1976	**38**	**2016**	**3**
1977	**37**	**2017**	**3**
1978	**36**	**2018**	**0**
1979	35	2019	0
1980	34	2020	1
1981	33	2021	1
1982	32	2022	0
1983	31	2023	0
1984	30	2024	0
1985	29	2025	0
1986	28	2026	0
1987	27	2027	4
1988	26	2028	2
1989	25	2029	1
1990	24	2030	3
1991	23	2031	1
1992	22	2032	0
1993	21	2033	0
1994	20	2034	0
1995	19	2035	1
1996	18	2036	0
1997	17	2037	0
1998	16	2038	0
1999	15	2039	0
2000	14	2040	0
2001	13	2041	1
2002	12	2042	2
2003	11	2043	1
2004	10	2044	3
2005	9	2045	0
2006	8	2046	3
2007	7	2047	0
2008	6	2048	1
2009	5	2049	3
2010	4	2050	0
2011	3	2051	2
2012	2	2052	1
2013	1	2053	0
2014	0	2054	0
Total			**38**

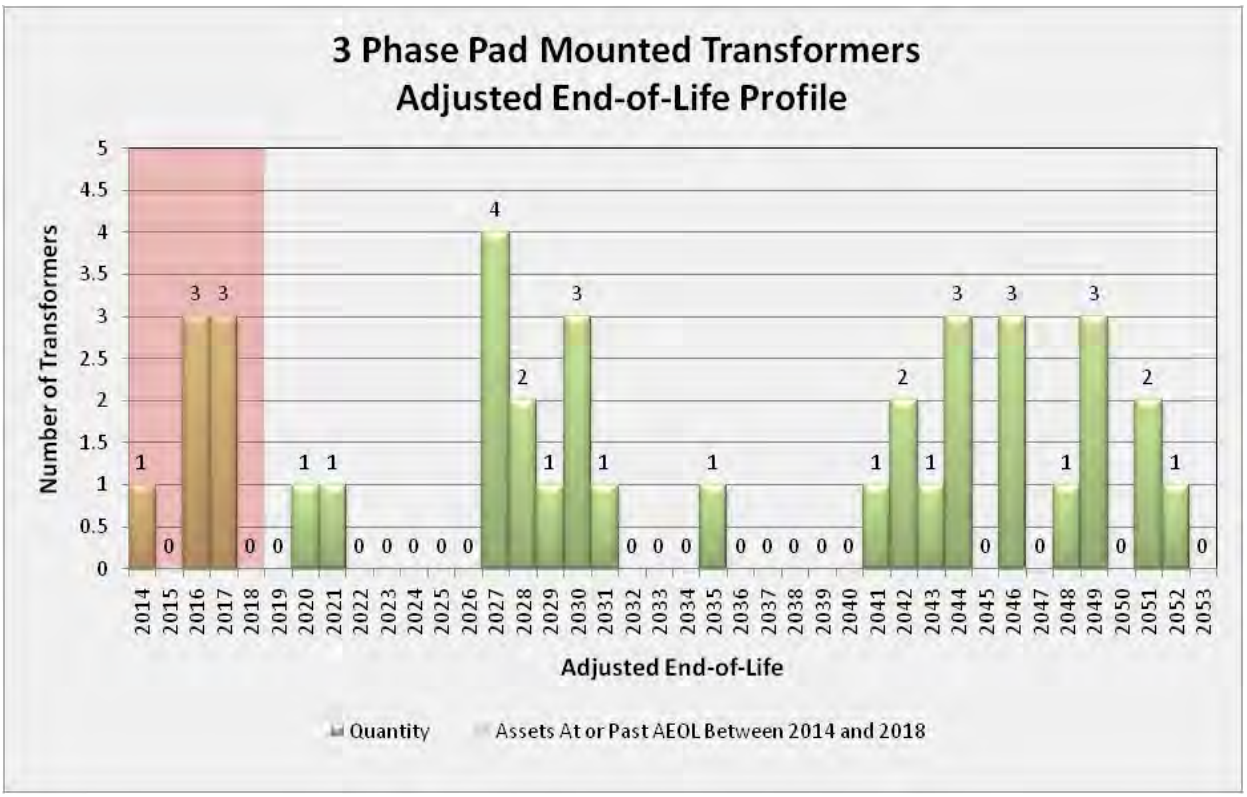


5.3.2.2.f.vi.6 Three Phase Pad-Mounted Transformers Adjusted End-of-Life Projections

FFPC performs detailed inspections of pad-mounted transformers on an annual basis. The results of the inspections are used to assess the overall health of transformers with respect to age. Physical defects, such as oil leaks or cracked bushings, indicate that a transformer is very near to the end of its useful life having a high probability of failure. FFPC has assigned adjusted end-of-life dates to individual transformers using FFPC's asset management process. It is important to note that the adjusted end-of-life values are of higher importance as assets approach their TUL, as opposed to during their earlier years.

FFPC is also currently working on recording the relationship of transformers to customers, which will allow for analysis of electrical loading from smart meter data. Smart meter data will essentially give FFPC insight into individual transformer utilization (loading). Electrical loading is a large contributor of transformer degradation, and as such, being able to quantify it will greatly enhance FFPC's ability of predicting transformer failures. The following table and graph illustrate the adjusted end-of-life profile for FFPC's Three Phase Pad-Mounted Transformer fleet, based on the most recent inspection results.

Three Phase Pad-Mounted Transformers Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**1**	**$ 25,106.29**	**0.950**
2	**2015**	**0**	**$ -**	**0.950**
3	**2016**	**3**	**$ 66,318.87**	**0.950**
4	**2017**	**3**	**$ 55,737.58**	**0.950**
5	**2018**	**0**	**$ -**	**0.950**
6	2019	0	$ -	0.950
7	2020	1	$ 20,106.29	0.950
8	2021	1	$ 20,106.29	0.950
9	2022	0	$ -	0.950
10	2023	0	$ -	0.950
11	2024	0	$ -	0.950
12	2025	0	$ -	0.950
13	2026	0	$ -	0.950
14	2027	4	$ 76,425.16	0.950
15	2028	2	$ 38,212.58	0.950
16	2029	1	$ 20,106.29	0.950
17	2030	3	$ 63,318.87	0.950
18	2031	1	$ 25,106.29	0.950
19	2032	0	$ -	0.950
20	2033	0	$ -	0.950
21	2034	0	$ -	0.950
22	2035	1	$ 25,106.29	0.950
23	2036	0	$ -	0.950
24	2037	0	$ -	0.950
25	2038	0	$ -	0.950
26	2039	0	$ -	0.950
27	2040	0	$ -	0.950
28	2041	1	$ 23,106.29	0.950
29	2042	2	$ 45,212.58	0.950
30	2043	1	$ 25,106.29	0.950
31	2044	3	$ 68,612.58	0.950
32	2045	0	$ -	0.950
33	2046	3	$ 61,112.58	0.950
34	2047	0	$ -	0.950
35	2048	1	$ 23,106.29	0.950
36	2049	3	$ 63,812.58	0.950
37	2050	0	$ -	0.950
38	2051	2	$ 46,212.58	0.950
39	2052	1	$ 16,100.00	0.950
40	2053	0	$ -	0.950
Totals		**38**	**$ 808,032.57**	**38**



5.3.2.2.f.vi.7 Lifecycle Analysis Summary & Budget Allocation

Three Phase Pad-Mounted Transformers Profile			
38	Quantity	1.3	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL	7	Quantity Reaching Adjusted End of Life Over Forecast Period
20.1	Average Age of Population	$147,163	Total Capital Replacement Cost over Forecast Period
0.95	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
50.1%	% UL Consumed	1.40	Average Replacements Per Year
62.6%	2019 % UL Consumed with no Reinvestment	$29,433	Average Annual Cost Per Year
		$20,201	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$147,163	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 38 three phase pad-mounted transformers is sporadic; however, fairly evenly weighted over one lifecycle period beginning in 2014. Approximately 55% (21 transformers) will require replacement over the first half of the lifecycle period (over the next 20 years).

FFPC adopted a UL of 40 years, and based on the average age of 20.1 years for the population, 50.1% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 62.6% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced or installed an average of 1.3 three phase pad-mounted transformers per year, which is slightly higher than the ideal average annual replacement rate of 0.95 transformers per year. Over the 2014 to 2018 forecast period, an estimated 7 transformers will reach their AEOL, requiring replacement. The total estimated capital replacement cost is $147,163, which has been allocated. No capital refurbishments have been allocated as transformers are not conducive to refurbishing. The average annual replacement rate is projected to be 1.4 transformers per year, and the average total annual reinvestment is $29,433 per year. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $20,201 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated a total of $147,163 towards capital replacements and no capital for refurbishments over the 2014 to 2018 planning period. This is approximately 46% higher than the ideal average annual reinvestment need, due to the sporadic distribution of projected failures.

5.3.2.2.f.vi.8 Impact of Three Phase Pad-Mounted Transformers on DS Plan

The planned reinvestment into three phase pad-mounted transformers has a material impact on FFPC's DS Plan. The total capital replacement cost of $147,163 for the transformers represents 4.2% of the total planned capital expenditures over the 2014 to 2018 planning horizon.

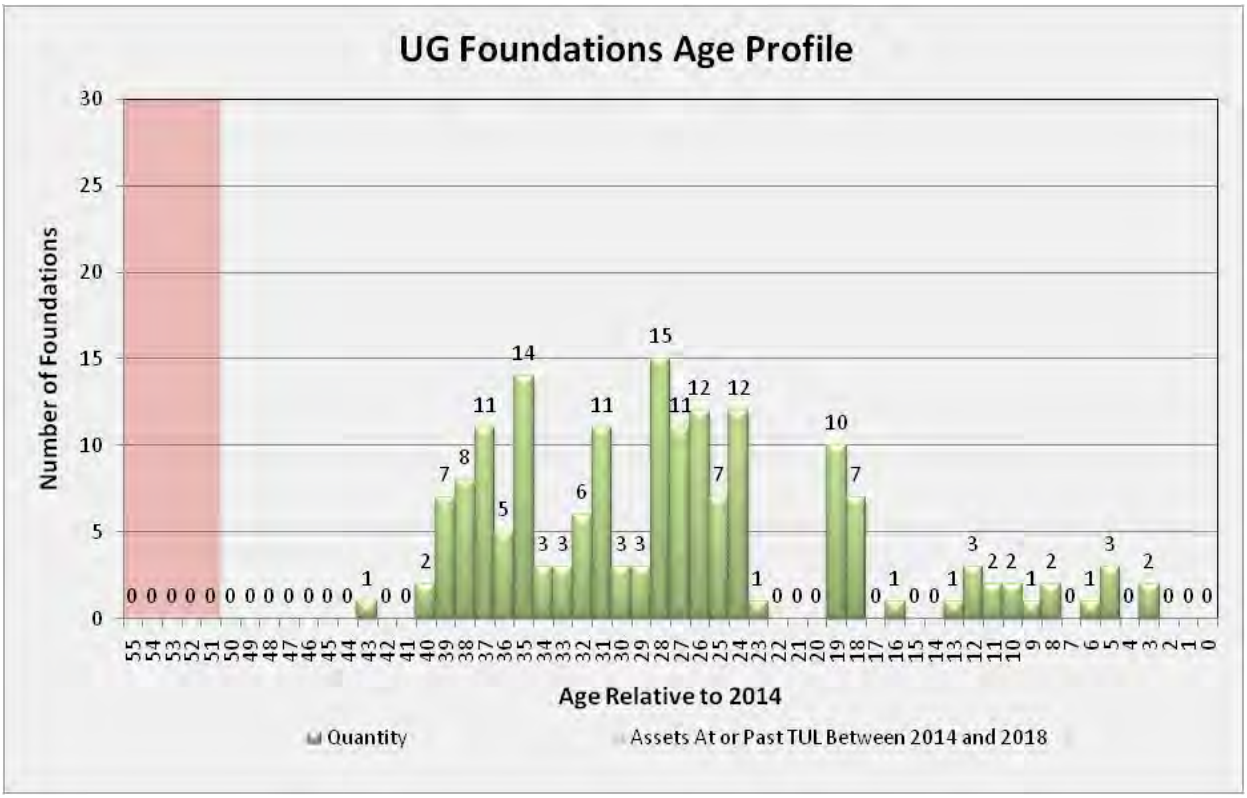
5.3.2.2.f.vii. Underground Foundations

FFPC has 170 underground foundations installed to support its pad-mounted transformer fleet. The foundations are essentially buried pre-casted cement vaults. FFPC has several legacy three phase pad-mount transformer settings, which utilize three individual pole mounted transformers arranged as a three phase bank. The transformers are mounted on an underground foundation, as well as they are covered by metal enclosures for protection. These settings will be replaced with modern day three phase pad-mounted transformers upon them reaching the end of their useful service life. FFPC has adopted the UL value of 80 years, compared to the 55 year TUL as per the "Kinectrics Report". FFPC's strategy is to sustain underground foundations such they will last 80 years, which would correspond to two full transformer lifecycles. FFPC does not expect to incur any significant expenses in this category over the 2014 to 2018 planning period, due to the relatively young age of the installations. FFPC will monitor the appropriateness of its adopted 80 years UL through its inspection program.

5.3.2.2.f.vii.1 Underground Foundations Age Profile Relative to TUL

The following table and graph represent the age of FFPC's Underground Foundations with respect to a TUL of 55 years.

UG Foundations Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 55 Year TUL)**	**Quantity**
1959	**55**	**2014**	**0**
1960	**54**	**2015**	**0**
1961	**53**	**2016**	**0**
1962	**52**	**2017**	**0**
1963	**51**	**2018**	**0**
1964	50	2019	0
1965	49	2020	0
1966	48	2021	0
1967	47	2022	0
1968	46	2023	0
1969	45	2024	0
1970	44	2025	0
1971	43	2026	1
1972	42	2027	0
1973	41	2028	0
1974	40	2029	2
1975	39	2030	7
1976	38	2031	8
1977	37	2032	11
1978	36	2033	5
1979	35	2034	14
1980	34	2035	3
1981	33	2036	3
1982	32	2037	6
1983	31	2038	11
1984	30	2039	3
1985	29	2040	3
1986	28	2041	15
1987	27	2042	11
1988	26	2043	12
1989	25	2044	7
1990	24	2045	12
1991	23	2046	1
1992	22	2047	0
1993	21	2048	0
1994	20	2049	0
1995	19	2050	10
1996	18	2051	7
1997	17	2052	0
1998	16	2053	1
1999	15	2054	0
2000	14	2055	0
2001	13	2056	1
2002	12	2057	3
2003	11	2058	2
2004	10	2059	2
2005	9	2060	1
2006	8	2061	2
2007	7	2062	0
2008	6	2063	1
2009	5	2064	3
2010	4	2065	0
2011	3	2066	2
2012	2	2067	0
2013	1	2068	0
2014	0	2069	0
Total			**170**

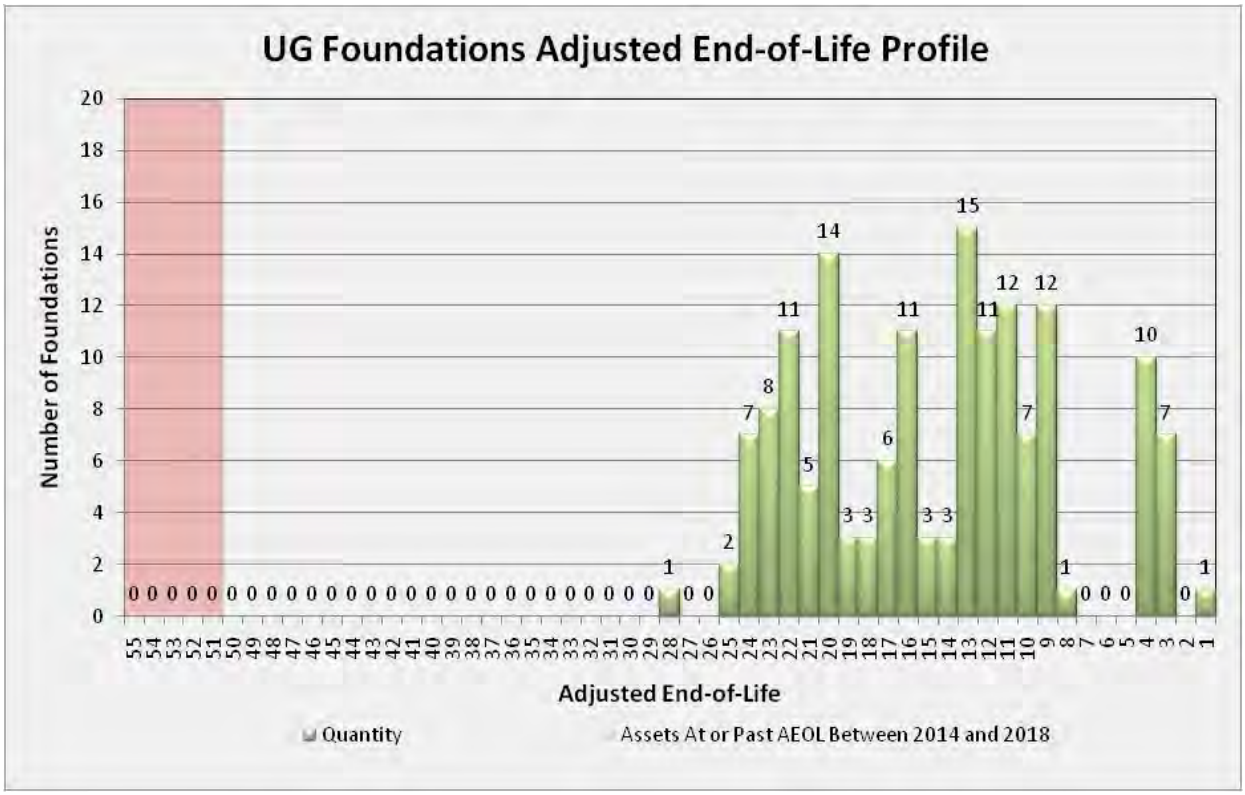


5.3.2.2.f.vii.2 Underground Foundations Adjusted End-of-Life Projections

FFPC inspects all underground foundations annually as part of its pad-mounted transformer inspection cycle. Overall, the foundations are found to be in good condition relative to their age. FFPC's strategy is to align two transformer lifecycles with one underground foundation lifecycle. In other words, FFPC is planning on replacing underground foundations under an 80 year lifecycle. FFPC will place more emphasis on inspecting underground foundations as they approach their TUL of 55 years, as per the "Kinectrics Report". FFPC does not plan on incurring any significant expenses in this category during the 2014 to 2018 period, given the relatively young age of population. The following table and graph illustrate the Adjusted End-of-Life Projections.

Underground Foundations Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	2014	0	$ -	2.1
2	2015	0	$ -	2.1
3	2016	0	$ -	2.1
4	2017	0	$ -	2.1
5	2018	0	$ -	2.1
6	2019	0	$ -	2.1
7	2020	0	$ -	2.1
8	2021	0	$ -	2.1
9	2022	0	$ -	2.1
10	2023	0	$ -	2.1
11	2024	0	$ -	2.1

12	2025	0	$ -	2.1
13	2026	0	$ -	2.1
14	2027	0	$ -	2.1
15	2028	0	$ -	2.1
16	2029	0	$ -	2.1
17	2030	0	$ -	2.1
18	2031	0	$ -	2.1
19	2032	0	$ -	2.1
20	2033	0	$ -	2.1
21	2034	0	$ -	2.1
22	2035	0	$ -	2.1
23	2036	0	$ -	2.1
24	2037	0	$ -	2.1
25	2038	0	$ -	2.1
26	2039	0	$ -	2.1
27	2040	0	$ -	2.1
28	2041	1	$ 4,443.60	2.1
29	2042	0	$ -	2.1
30	2043	0	$ -	2.1
31	2044	2	$ 10,691.55	2.1
32	2045	7	$ 31,105.20	2.1
33	2046	8	$ 40,961.85	2.1
34	2047	11	$ 52,488.30	2.1
35	2048	5	$ 22,218.00	2.1
36	2049	14	$ 62,210.40	2.1
37	2050	3	$ 15,135.15	2.1
38	2051	3	$ 15,135.15	2.1
39	2052	6	$ 26,661.60	2.1
40	2053	11	$ 48,879.60	2.1
41	2054	3	$ 13,330.80	2.1
42	2055	3	$ 13,330.80	2.1
43	2056	15	$ 66,654.00	2.1
44	2057	11	$ 56,097.00	2.1
45	2058	12	$ 56,931.90	2.1
46	2059	7	$ 32,909.55	2.1
47	2060	12	$ 58,736.25	2.1
48	2061	1	$ 6,247.95	2.1
49	2062	0	$ -	2.1
50	2063	0	$ -	2.1
51	2064	0	$ -	2.1
52	2065	10	$ 46,240.35	2.1
53	2066	7	$ 31,105.20	2.1
54	2067	0	$ -	2.1
55	2068	1	$ 4,443.60	2.1
56	2069	0	$ -	2.1
57	2070	0	$ -	2.1
58	2071	1	$ 6,247.95	2.1
59	2072	3	$ 16,939.50	2.1
60	2073	2	$ 10,691.55	2.1
61	2074	2	$ 12,495.90	2.1
62	2075	1	$ 4,443.60	2.1
63	2076	2	$ 12,495.90	2.1
64	2077	0	$ -	2.1
65	2078	1	$ 6,247.95	2.1
66	2079	3	$ 16,939.50	2.1
67	2080	0	$ -	2.1
68	2081	2	$ 12,495.90	2.1
69	2082	0	$ -	2.1
70	2083	0	$ -	2.1
71	2084	0	$ -	2.1
72	2085	0	$ -	2.1
73	2086	0	$ -	2.1
74	2087	0	$ -	2.1
75	2088	0	$ -	2.1
76	2089	0	$ -	2.1
77	2090	0	$ -	2.1
78	2091	0	$ -	2.1
79	2092	0	$ -	2.1
80	2093	0	$ -	2.1
Totals		**170**	**$ 814,955.55**	**170**



5.3.2.2.f.vii.3 Lifecycle Analysis Summary & Budget Allocation

Underground Foundations Profile			
170	Quantity	1.1	10 Year Historic Replacement/Installation Rate (Units/Year)
80	UL (Adopted)	0	Quantity Reaching Adjusted End of Life Over Forecast Period
27.5	Average Age of Population	$0	Total Capital Replacement Cost over Forecast Period
3.09	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
34.4%	% UL Consumed	0.00	Average Replacements Per Year
40.6%	2019 % UL Consumed with no Reinvestment	$0	Average Annual Cost Per Year
		$10,187	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$0	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 170 Underground Foundations is not evenly distributed over one lifecycle period beginning in 2014. The population is negatively skewed, with essentially no assets requiring replacement over the next 27 years. It should be noted that this is largely due to FFPC adopting a UL of 80 years, to align the replacement with every second transformer replacement.

Approximately 42% (71 UG foundations) will require replacement over the first half of the lifecycle period (over the next 40 years); beginning in year 28. FFPC adopted a UL of 80 years, and based on the average age of 27.5 years for the population, 34.4% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 40.6% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced or installed an average of 2.2 foundations per year, which is closely aligned with the ideal average annual replacement rate of 2.13 foundations per year. Over the 2014 to 2018 forecast period, no underground foundations will reach their AEOL, requiring replacement. As such, FFPC has not allocated any capital towards this asset class. Recent inspection finding have not found any deficiencies, and as such, no capital refurbishment costs have been allocated. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $10,187 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. As this asset class is not projected to demand capital investment over the planning period, it will allow FFPC to shift expenditures towards asset classes that require intensified reinvestment, to smooth long term spending requirements.

5.3.2.2.f.vii.4 Impact of Underground Foundations on DS Plan

As no expenditures as allocated towards this asset class over the planning period, underground foundations will not have an impact on the DS Plan with respect to capital requirements; however, this will allow for intensified capital reinvestments into asset classes where it is required.

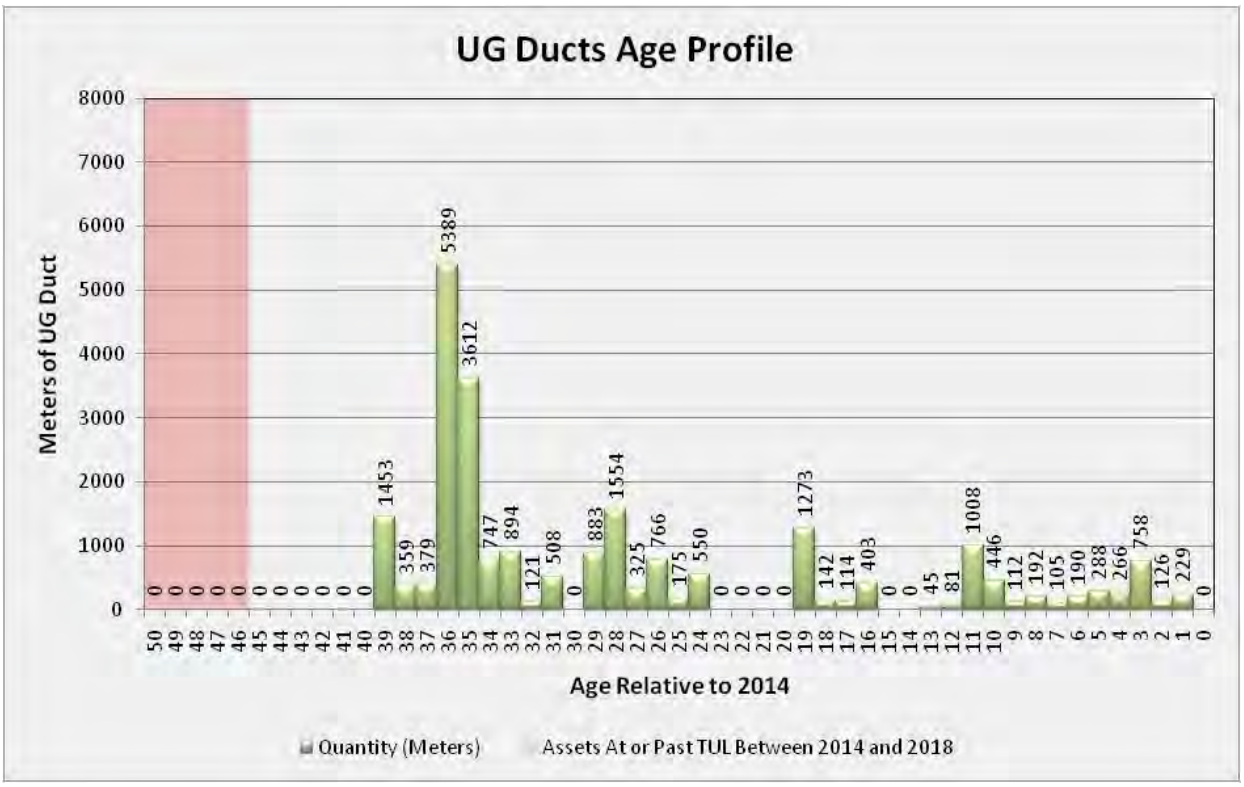
5.3.2.2.f.viii. Underground Ducts

FFPC's primary cables are all contained in ducts for added protection. FFPC does not plan on incurring any significant expense in this category over the period 2014 to 2018, given the relatively young age of FFPC's ducts. FFPC's strategy is to align the life two useful life cycles of Primary TR XLPE Cables in Duct with one lifecycle for Ducts. As such, FFPC would be replacing primary cables and ducts combined on an 80 year cycle.

5.3.2.2.f.viii.1 Underground Ducts Age Profile Relative to TUL

The following table and graph represents the age profile of FFPC's Ducts, with respect to a TUL of 50 years as per the "Kinectrics Report".

UG Ducts Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age (Years in Service)**	**End-of-Life (Based on 50 Year TUL)**	**Quantity (Meters)**
1964	50	2014	0
1965	49	2015	0
1966	48	2016	0
1967	47	2017	0
1968	46	2018	0
1969	45	2019	0
1970	44	2020	0
1971	43	2021	0
1972	42	2022	0
1973	41	2023	0
1974	40	2024	0
1975	39	2025	1453
1976	38	2026	359
1977	37	2027	379
1978	36	2028	5389
1979	35	2029	3612
1980	34	2030	747
1981	33	2031	894
1982	32	2032	121
1983	31	2033	508
1984	30	2034	0
1985	29	2035	883
1986	28	2036	1554
1987	27	2037	325
1988	26	2038	766
1989	25	2039	175
1990	24	2040	550
1991	23	2041	0
1992	22	2042	0
1993	21	2043	0
1994	20	2044	0
1995	19	2045	1273
1996	18	2046	142
1997	17	2047	114
1998	16	2048	403
1999	15	2049	0
2000	14	2050	0
2001	13	2051	45
2002	12	2052	81
2003	11	2053	1008
2004	10	2054	446
2005	9	2055	112
2006	8	2056	192
2007	7	2057	105
2008	6	2058	190
2009	5	2059	288
2010	4	2060	266
2011	3	2061	758
2012	2	2062	126
2013	1	2063	229
2014	0	2064	0
Total			**23,491.88**

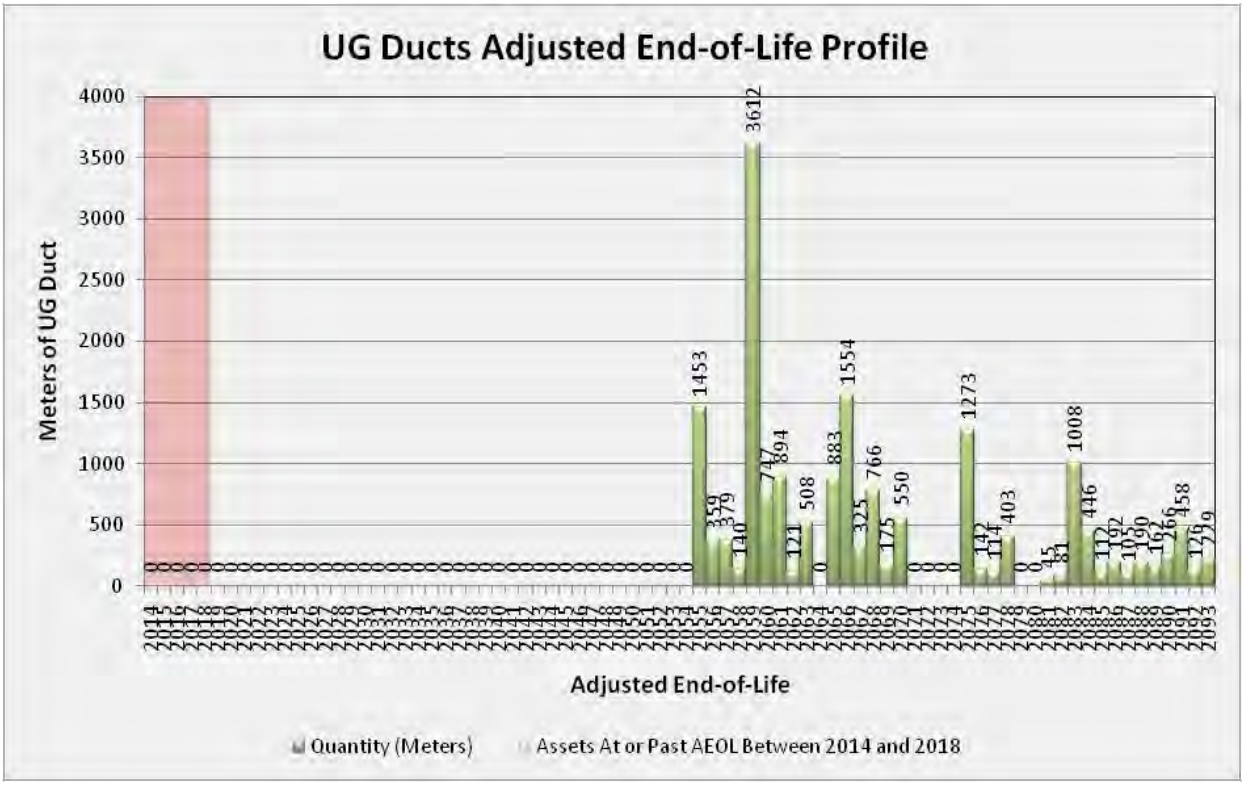


5.3.2.2.f.viii.2 Underground Ducts Adjusted End-of-Life Projections

FFPC currently does not have any means of inspecting underground ducts. FFPC's strategy is to replace ducts according to the lifecycle of primary conductors which they house. As such, FFPC is planning on replacing underground ducts according to two lifecycles of Primary TR XLPE Cables in Duct, as per the "Kinectrics Report", which would be on an 80 year lifecycle. FFPC has set its Adjusted Useful Life to correspond to an 80 year lifecycle, as per the following table and graph. As previously mentioned, FFPC does not plan on incurring any significant expense in this category given the relatively young age of the ducts.

UG Ducts Adjusted End-of-Life Profile Based on Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity (Meters)**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	2014	0	$ -	222.7
2	2015	0	$ -	222.7
3	2016	0	$ -	222.7
4	2017	0	$ -	222.7
5	2018	0	$ -	222.7
6	2019	0	$ -	222.7
7	2020	0	$ -	222.7
8	2021	0	$ -	222.7
9	2022	0	$ -	222.7
10	2023	0	$ -	222.7
11	2024	0	$ -	222.7
12	2025	0	$ -	222.7
13	2026	0	$ -	222.7
14	2027	0	$ -	222.7
15	2028	0	$ -	222.7
16	2029	0	$ -	222.7
17	2030	0	$ -	222.7
18	2031	0	$ -	222.7
19	2032	0	$ -	222.7
20	2033	0	$ -	222.7
21	2034	0	$ -	222.7
22	2035	0	$ -	222.7
23	2036	0	$ -	222.7
24	2037	0	$ -	222.7
25	2038	0	$ -	222.7
26	2039	0	$ -	222.7
27	2040	0	$ -	222.7
28	2041	0	$ -	222.7
29	2042	0	$ -	222.7
30	2043	0	$ -	222.7
31	2044	0	$ -	222.7
32	2045	0	$ -	222.7
33	2046	0	$ -	222.7
34	2047	0	$ -	222.7
35	2048	0	$ -	222.7
36	2049	0	$ -	222.7
37	2050	0	$ -	222.7
38	2051	0	$ -	222.7
39	2052	0	$ -	222.7
40	2053	0	$ -	222.7
41	2054	0	$ -	222.7
42	2055	1453	$ 30,066.89	222.7
43	2056	359	$ 4,970.40	222.7
44	2057	379	$ 7,865.58	222.7
45	2058	140	$ 1,108.42	222.7
46	2059	3612	$ 57,013.11	222.7
47	2060	747	$ 16,569.19	222.7
48	2061	894	$ 19,831.38	222.7
49	2062	121	$ 2,678.48	222.7
50	2063	508	$ 4,943.03	222.7
51	2064	0	$ -	222.7
52	2065	883	$ 12,515.23	222.7
53	2066	1554	$ 27,959.11	222.7
54	2067	325	$ 7,203.93	222.7
55	2068	766	$ 13,395.59	222.7
56	2069	175	$ 3,608.77	222.7
57	2070	550	$ 8,133.78	222.7
58	2071	0	$ -	222.7
59	2072	0	$ -	222.7

60	2073	0	$ -	222.7
61	2074	0	$ -	222.7
62	2075	1273	$ 21,213.19	222.7
63	2076	142	$ 2,341.70	222.7
64	2077	114	$ 705.51	222.7
65	2078	403	$ 8,938.18	222.7
66	2079	0	$ -	222.7
67	2080	0	$ -	222.7
68	2081	45	$ 998.26	222.7
69	2082	81	$ 1,787.74	222.7
70	2083	1008	$ 22,350.46	222.7
71	2084	446	$ 9,897.47	222.7
72	2085	112	$ 696.29	222.7
73	2086	192	$ 4,248.59	222.7
74	2087	105	$ 2,338.34	222.7
75	2088	190	$ 3,644.74	222.7
76	2089	162	$ 3,593.73	222.7
77	2090	266	$ 5,911.60	222.7
78	2091	458	$ 8,880.98	222.7
79	2092	126	$ 2,312.79	222.7
80	2093	229	$ 5,078.94	222.7
Totals		**17817**	**$ 322,801.40**	**17,816.8**



5.3.2.2.f.viii.3 Lifecycle Analysis Summary & Budget Allocation

Underground Ducts Profile			
23492	Quantity (Meters)	271	10 Year Historic Replacement/Installation Rate (Units/Year)
80	UL (Adopted)	0	Quantity Reaching Adjusted End of Life Over Forecast Period
27.9	Average Age of Population	$0	Total Capital Replacement Cost over Forecast Period
469.84	Ideal Equalized Annual Replacement Rate (Meters/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
34.9%	% UL Consumed	$0	Average Replacements Per Year
41.2%	2019 % UL Consumed with no Reinvestment	$0	Average Annual Cost Per Year
		$4,035	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$0	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 23.5 km of Underground Ducts is not evenly distributed over one lifecycle period beginning in 2014. The population is negatively skewed, with essentially no assets requiring replacement over the next 41 years. It should be noted that this is largely due to FFPC adopting a UL of 80 years, to align the replacement with every second primary conductor that they house. No ducts are projected to require replacement over the first half of the lifecycle period (over the next 40 years). FFPC adopted a UL of 80 years, and based on the average age of 27.9 years for the population, 34.9% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 41.2% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced or installed an average of 0.27 km of ducts per year, which is closely aligned with the ideal average annual replacement rate of 0.29 km of ducts per year. Over the 2014 to 2018 forecast period, no underground ducts are projected to reach their AEOL, requiring replacement. As such FFPC has not allocated any capital towards this asset class. Recent inspection finding have not found any deficiencies, and as such, no capital refurbishment costs have been allocated. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $4,035 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. As this asset is not projected to demand capital investment over the planning period, it will allow FFPC to shift expenditures towards asset classes that require intensified reinvestment, to smooth long term spending requirements.

5.3.2.2.f.viii.4 Impact on of Underground Ducts on DS Plan

As no expenditures as allocated towards this asset class over the planning period, underground foundations will not have an impact on the DS Plan with respect to cost requirements; however, this will allow for intensified capital reinvestments into asset classes where it is required.

5.3.2.2.f.ix. Concrete Encased Duct Banks

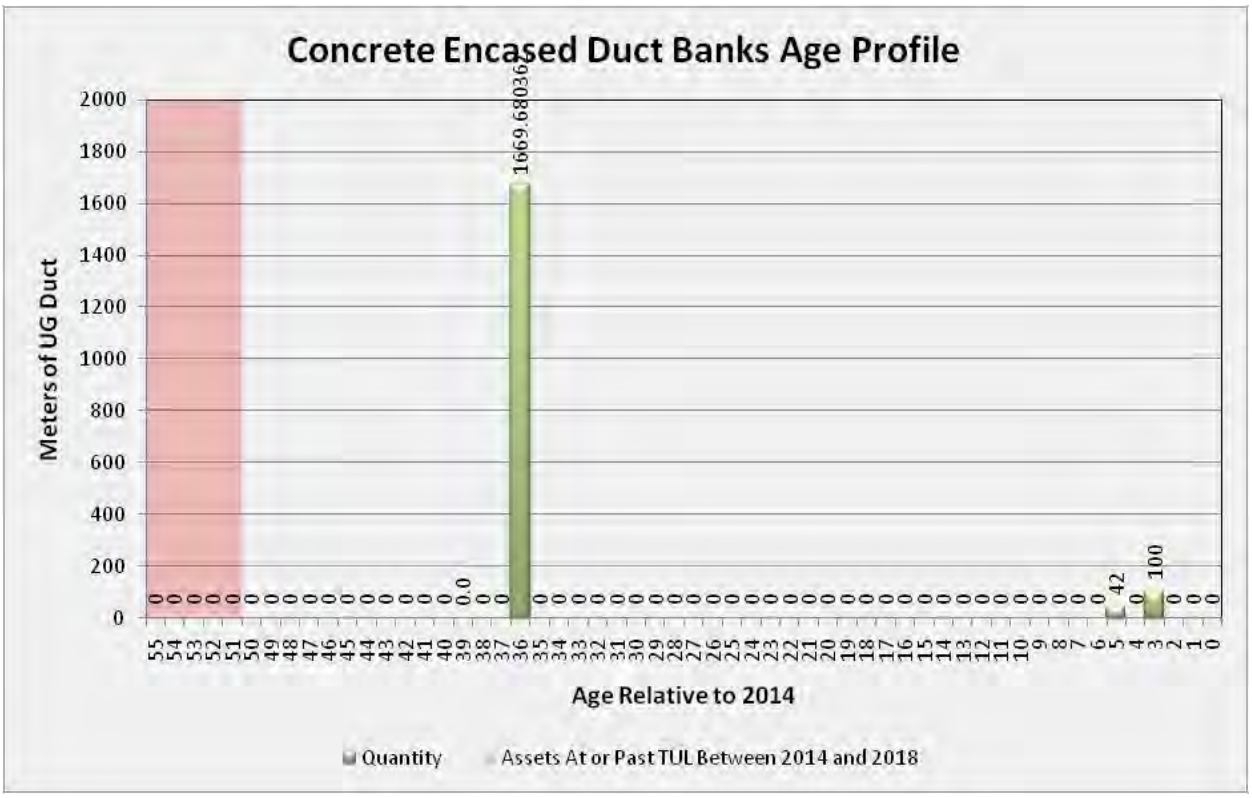
Approximately one-third of all of FFPC underground ducts are cement encased. The cement encased ducts are mostly located around the transformer station Fort Frances MTS, where they guide three feeders to their respective breaker in the station. Due to the importance of these underground sections of primary conductor, the ducts are cement encased for their added protection. The following picture shows the original installation of cement encased ducts that connect three of FFPC's feeders to their respective transformer station breaker.



5.3.2.2.f.ix.1 Concrete Encased Duct Banks Age Profile Relative to TUL

FFPC has adopted a UL of 80 years for Concrete Encased Duct Banks, which compares to a 55 year TUL as per the "Kinectrics Report". FFPC plans on extending the life of the duct banks according to the replacement schedule of the cables that they house. As such, FFPC plans on replacing the ducts every second time that the 40 year lifecycle primary cables are replaced, which is every 80 years. The following graph and table illustrate the TUL of FFPC's Concrete Encased Ducts Banks as per the 55 year TUL established in the "Kinectrics Report".

Concrete Encased Duct Banks Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 55 Year TUL)**	**Quantity**
1959	55	2014	0
1960	54	2015	0
1961	53	2016	0
1962	52	2017	0
1963	51	2018	0
1964	50	2019	0
1965	49	2020	0
1966	48	2021	0
1967	47	2022	0
1968	46	2023	0
1969	45	2024	0
1970	44	2025	0
1971	43	2026	0
1972	42	2027	0
1973	41	2028	0
1974	40	2029	0
1975	39	2030	0.0
1976	38	2031	0
1977	37	2032	0
1978	36	2033	1,669.7
1979	35	2034	0
1980	34	2035	0
1981	33	2036	0
1982	32	2037	0
1983	31	2038	0
1984	30	2039	0
1985	29	2040	0
1986	28	2041	0
1987	27	2042	0
1988	26	2043	0
1989	25	2044	0
1990	24	2045	0
1991	23	2046	0
1992	22	2047	0
1993	21	2048	0
1994	20	2049	0
1995	19	2050	0
1996	18	2051	0
1997	17	2052	0
1998	16	2053	0
1999	15	2054	0
2000	14	2055	0
2001	13	2056	0
2002	12	2057	0
2003	11	2058	0
2004	10	2059	0
2005	9	2060	0
2006	8	2061	0
2007	7	2062	0
2008	6	2063	0
2009	5	2064	42
2010	4	2065	0
2011	3	2066	100
2012	2	2067	0
2013	1	2068	0
2014	0	2069	0
Total			**1,811.7**

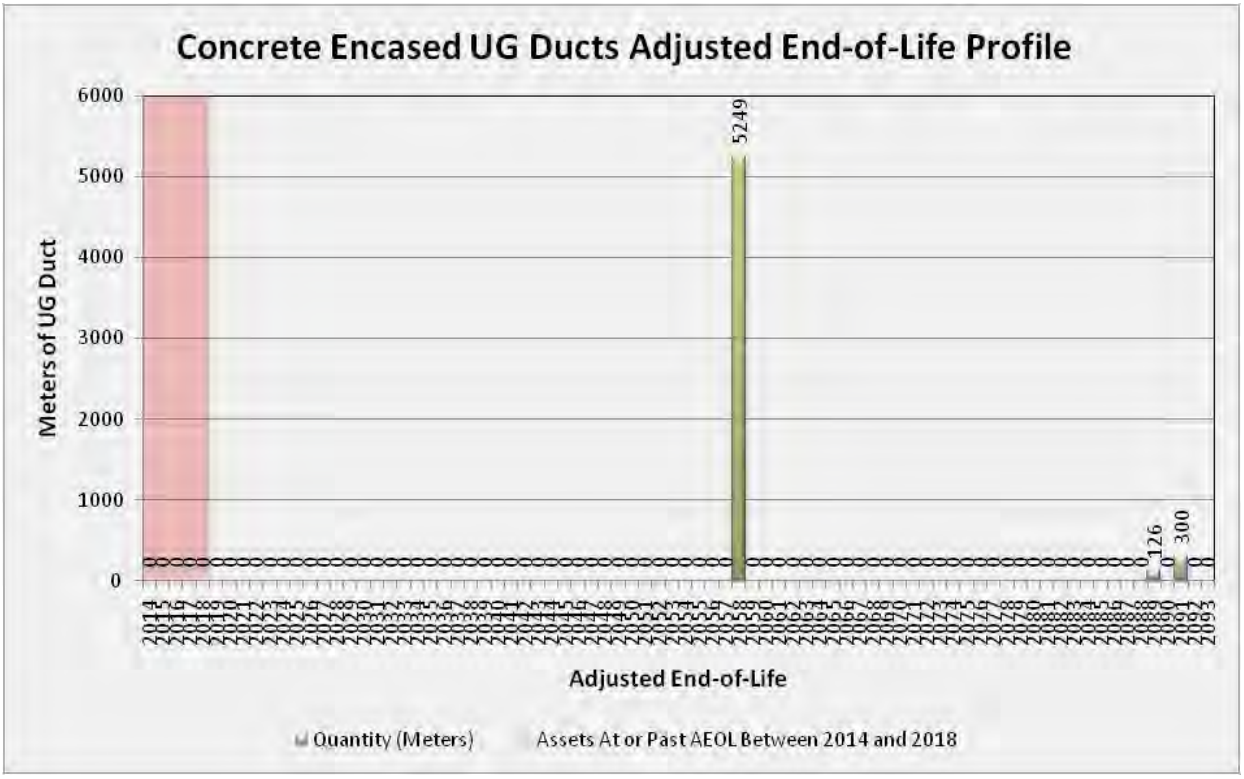


5.3.2.2.f.ix.2 Concrete Encased Duct Banks Adjusted End-of-Life Projections

FFPC currently does not have any practical means of inspecting the duct banks. FFPC's strategy is to replace ducts according to the lifecycle of primary conductor which they house. As such, FFPC is planning on replacing the concrete encased ducts according to two lifecycles of Primary TR XLPE Cables in Duct as per the "Kinectrics Report", which would be based on an 80 year lifecycle. FFPC has set its Adjusted Useful Life to correspond to an 80 year lifecycle, as illustrated the following table and graph. It is very likely that most of these ducts will become obsolete upon the retirement of the transformer station Fort Frances MTS around 2034. In summation, FFPC does not plan on incurring any significant expense in this category during the period 2014 to 2018.

Concrete Encased UG Ducts Adjusted End-of-Life Profile Based on Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity (Meters)**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	2014	0	$ -	70.9
2	2015	0	$ -	70.9
3	2016	0	$ -	70.9
4	2017	0	$ -	70.9
5	2018	0	$ -	70.9
6	2019	0	$ -	70.9
7	2020	0	$ -	70.9
8	2021	0	$ -	70.9
9	2022	0	$ -	70.9
10	2023	0	$ -	70.9
11	2024	0	$ -	70.9
12	2025	0	$ -	70.9
13	2026	0	$ -	70.9
14	2027	0	$ -	70.9
15	2028	0	$ -	70.9
16	2029	0	$ -	70.9
17	2030	0	$ -	70.9
18	2031	0	$ -	70.9
19	2032	0	$ -	70.9
20	2033	0	$ -	70.9
21	2034	0	$ -	70.9
22	2035	0	$ -	70.9
23	2036	0	$ -	70.9
24	2037	0	$ -	70.9
25	2038	0	$ -	70.9
26	2039	0	$ -	70.9
27	2040	0	$ -	70.9
28	2041	0	$ -	70.9
29	2042	0	$ -	70.9
30	2043	0	$ -	70.9
31	2044	0	$ -	70.9
32	2045	0	$ -	70.9
33	2046	0	$ -	70.9
34	2047	0	$ -	70.9
35	2048	0	$ -	70.9
36	2049	0	$ -	70.9
37	2050	0	$ -	70.9
38	2051	0	$ -	70.9
39	2052	0	$ -	70.9
40	2053	0	$ -	70.9
41	2054	0	$ -	70.9
42	2055	0	$ -	70.9
43	2056	0	$ -	70.9
44	2057	0	$ -	70.9
45	2058	5,249	$ 659,476.40	70.9
46	2059	0	$ -	70.9
47	2060	0	$ -	70.9
48	2061	0	$ -	70.9
49	2062	0	$ -	70.9
50	2063	0	$ -	70.9
51	2064	0	$ -	70.9
52	2065	0	$ -	70.9
53	2066	0	$ -	70.9
54	2067	0	$ -	70.9
55	2068	0	$ -	70.9
56	2069	0	$ -	70.9
57	2070	0	$ -	70.9
58	2071	0	$ -	70.9
59	2072	0	$ -	70.9
60	2073	0	$ -	70.9
61	2074	0	$ -	70.9
62	2075	0	$ -	70.9
63	2076	0	$ -	70.9
64	2077	0	$ -	70.9
65	2078	0	$ -	70.9
66	2079	0	$ -	70.9
67	2080	0	$ -	70.9

68	2081	0	$ -	70.9
69	2082	0	$ -	70.9
70	2083	0	$ -	70.9
71	2084	0	$ -	70.9
72	2085	0	$ -	70.9
73	2086	0	$ -	70.9
74	2087	0	$ -	70.9
75	2088	0	$ -	70.9
76	2089	126	$ 15,830.33	70.9
77	2090	0	$ -	70.9
78	2091	300	$ 37,691.25	70.9
79	2092	0	$ -	70.9
80	2093	0	$ -	70.9
Totals		**5675**	**$ 712,997.97**	**5675.0**



5.3.2.2.f.ix.3 Lifecycle Analysis Summary & Budget Allocation

Concrete Encased Duct Banks Profile			
1812	Quantity (Meters)	14.2	10 Year Historic Replacement/Installation Rate (Units/Year)
80	UL (Adopted)	0	Quantity Reaching Adjusted End of Life Over Forecast Period
33.5	Average Age of Population	$0	Total Capital Replacement Cost over Forecast Period
32.94	Ideal Equalized Annual Replacement Rate (Meters/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
41.8%	% UL Consumed	0.00	Average Replacements Per Year
48.1%	2019 % UL Consumed with no Reinvestment	$0	Average Annual Cost Per Year
		$8,912	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$0	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 1.8 km of Underground Concrete Encased Duct Banks is not evenly distributed over one lifecycle period beginning in 2014. The population is negatively skewed, with essentially no assets requiring replacement over the next 43 years. It should be noted that this is largely due to FFPC adopting a UL of 80 years, to align the replacement with every second primary conductor that they house. No ducts are projected to require replacement over the first half of the lifecycle period (over the next 40 years). FFPC adopted a UL of 80 years, and based on the average age of 33.5 years for the population, 41.8% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 48.1% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced or installed an average of 0.014 km of concrete encased ducts per year, which is closely aligned with the ideal average annual replacement rate of 0.023 km per year. Over the 2014 to 2018 forecast period, no concrete encased ducts are projected to reach their AEOL, requiring replacement. As such FFPC has not allocated any capital towards this asset class. Recent inspections have not found any deficiencies, and as such, no capital refurbishment costs have been allocated. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $8,912 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. As this asset class is not projected to demand capital investment over the planning period, it will allow FFPC to shift expenditures towards asset classes that require intensified reinvestment, to smooth long term spending requirements.

5.3.2.2.f.ix.4 Impact of Concrete Encased Ducts on DS Plan

As no expenditures are allocated towards this asset class over the planning period, underground foundations will not have an impact on the DS Plan with respect to cost requirements; however, this will allow for intensified capital reinvestments into asset classes where it is required.

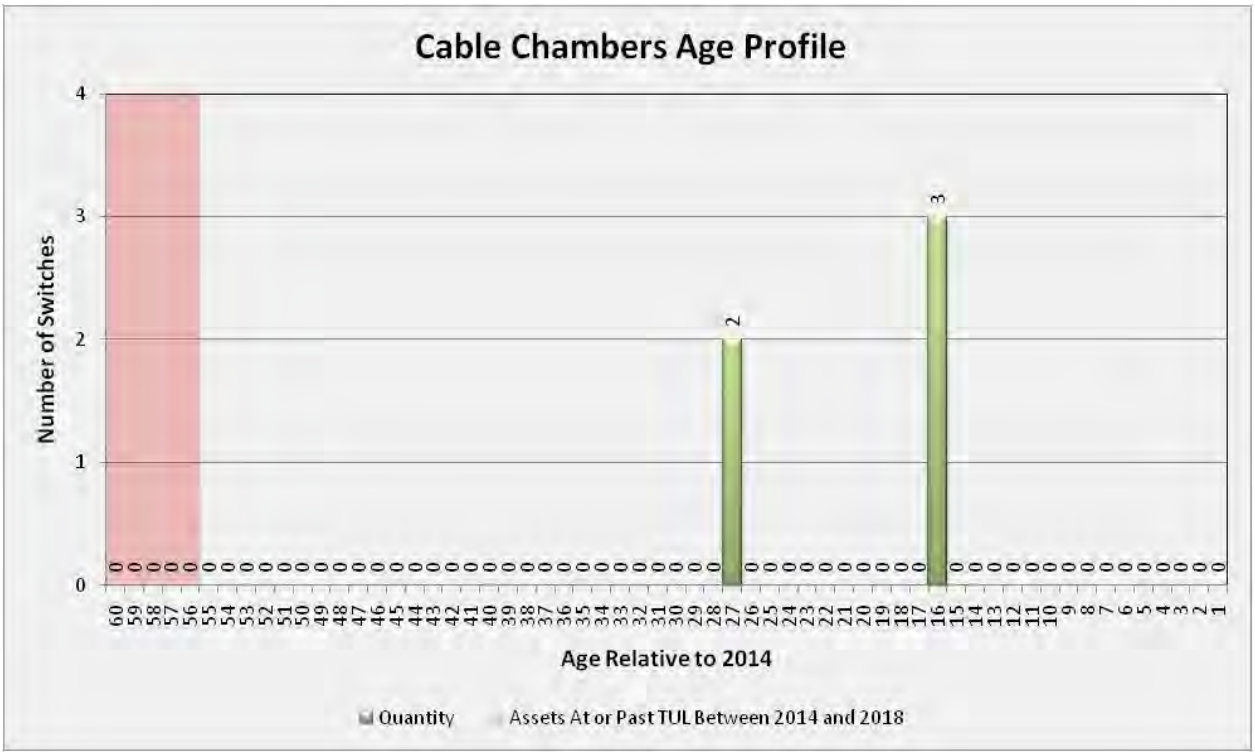
5.3.2.2.f.x. Cable Chambers

FFPC has several cable chambers located in several newer subdivisions, which are serviced by underground distribution plant. The cable chambers are essentially access points to underground conductor runs, such that terminations can be inspected, as well as any necessary cable switching can be performed there. FFPC's cable chambers are not near their end-of-life and as such FFPC does not plan on incurring any significant expenses in this category over the 2014 to 2018 planning period.

5.3.2.2.f.x.1 Cable Chambers Age Profile Relative to TUL

FFPC has adopted the TUL of 60 years for Cable Chambers, according to the "Kinectrics Report". The following table and graph illustrate the TUL of the Cable Chambers with respect to a 60 year TUL.

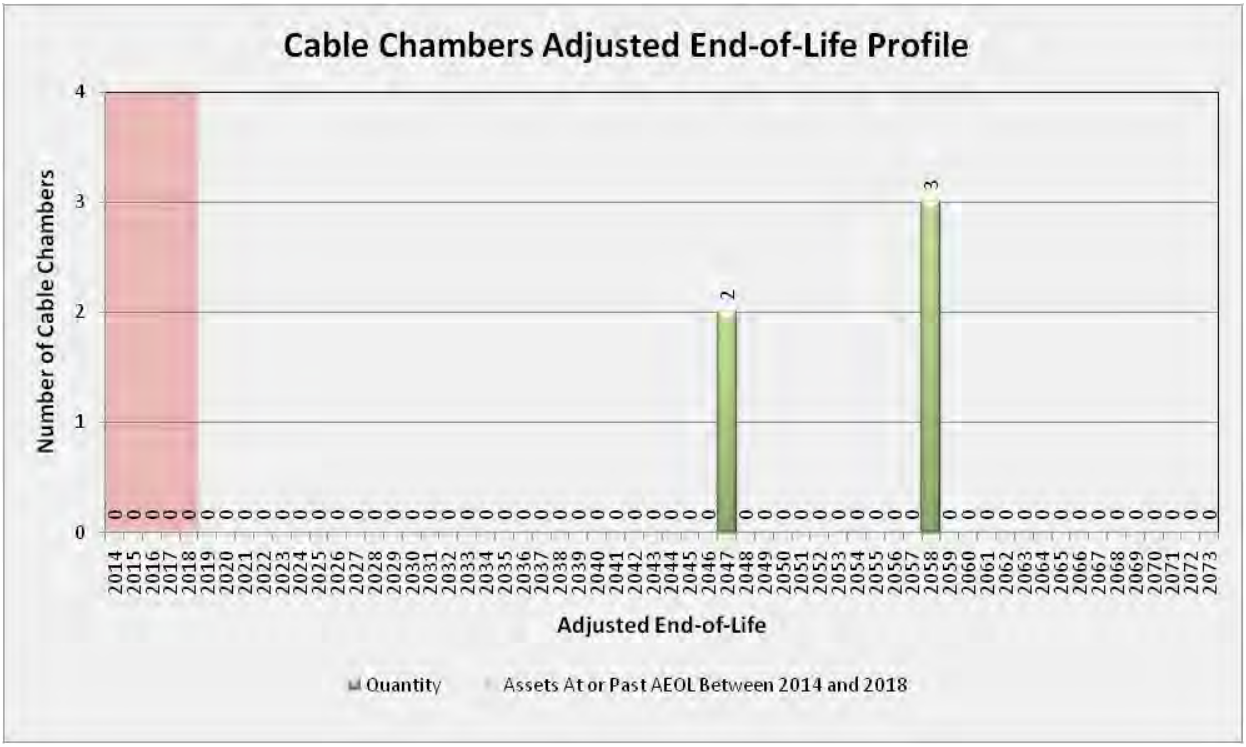
Cable Chambers Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	Age	End-of-Life (Based on 45 Year TUL)	Quantity
1954	**60**	**2014**	**0**
1955	**59**	**2015**	**0**
1956	**58**	**2016**	**0**
1957	**57**	**2017**	**0**
1958	**56**	**2018**	**0**
1959	55	2019	0
1960	54	2020	0
1961	53	2021	0
1962	52	2022	0
1963	51	2023	0
1964	50	2024	0
1965	49	2025	0
1966	48	2026	0
1967	47	2027	0
1968	46	2028	0
1969	45	2029	0
1970	44	2030	0
1971	43	2031	0
1972	42	2032	0
1973	41	2033	0
1974	40	2034	0
1975	39	2035	0
1976	38	2036	0
1977	37	2037	0
1978	36	2038	0
1979	35	2039	0
1980	34	2040	0
1981	33	2041	0
1982	32	2042	0
1983	31	2043	0
1984	30	2044	0
1985	29	2045	0
1986	28	2046	0
1987	27	2047	2
1988	26	2048	0
1989	25	2049	0
1990	24	2050	0
1991	23	2051	0
1992	22	2052	0
1993	21	2053	0
1994	20	2054	0
1995	19	2055	0
1996	18	2056	0
1997	17	2057	0
1998	16	2058	3
1999	15	2059	0
2000	14	2060	0
2001	13	2061	0
2002	12	2062	0
2003	11	2063	0
2004	10	2064	0
2005	9	2065	0
2006	8	2066	0
2007	7	2067	0
2008	6	2068	0
2009	5	2069	0
2010	4	2070	0
2011	3	2071	0
2012	2	2072	0
2013	1	2073	0
Total			**5**



5.3.2.2.f.x.2 Cable Chambers Adjusted End-of-Life Projections

FFPC performs annual inspections of its cable chambers, as well as of the cable terminations contained therein. To date all inspections have found the cable chambers to be in good condition relative to their age. The following table and graph illustrate the Adjusted End-of-Life projections for Cable Chambers, based on FFPC's asset management process. As previously mentioned, FFPC does not expect to incur any significant expenses in this category over the period 2014 to 2018.

Cable Chambers Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**0**	**$ -**	**0.1**
2	**2015**	**0**	**$ -**	**0.1**
3	**2016**	**0**	**$ -**	**0.1**
4	**2017**	**0**	**$ -**	**0.1**
5	**2018**	**0**	**$ -**	**0.1**
6	2019	0	$ -	0.1
7	2020	0	$ -	0.1
8	2021	0	$ -	0.1
9	2022	0	$ -	0.1
10	2023	0	$ -	0.1
11	2024	0	$ -	0.1
12	2025	0	$ -	0.1
13	2026	0	$ -	0.1
14	2027	0	$ -	0.1
15	2028	0	$ -	0.1
16	2029	0	$ -	0.1
17	2030	0	$ -	0.1
18	2031	0	$ -	0.1
19	2032	0	$ -	0.1
20	2033	0	$ -	0.1
21	2034	0	$ -	0.1
22	2035	0	$ -	0.1
23	2036	0	$ -	0.1
24	2037	0	$ -	0.1
25	2038	0	$ -	0.1
26	2039	0	$ -	0.1
27	2040	0	$ -	0.1
28	2041	0	$ -	0.1
29	2042	0	$ -	0.1
30	2043	0	$ -	0.1
31	2044	0	$ -	0.1
32	2045	0	$ -	0.1
33	2046	0	$ -	0.1
34	2047	2	$ 14,000	0.1
35	2048	0	$ -	0.1
36	2049	0	$ -	0.1
37	2050	0	$ -	0.1
38	2051	0	$ -	0.1
39	2052	0	$ -	0.1
40	2053	0	$ -	0.1
41	2054	0	$ -	0.1
42	2055	0	$ -	0.1
43	2056	0	$ -	0.1
44	2057	0	$ -	0.1
45	2058	3	$ 21,000	0.1
46	2059	0	$ -	0.1
47	2060	0	$ -	0.1
48	2061	0	$ -	0.1
49	2062	0	$ -	0.1
50	2063	0	$ -	0.1
51	2064	0	$ -	0.1
52	2065	0	$ -	0.1
53	2066	0	$ -	0.1
54	2067	0	$ -	0.1
55	2068	0	$ -	0.1
56	2069	0	$ -	0.1
57	2070	0	$ -	0.1
58	2071	0	$ -	0.1
59	2072	0	$ -	0.1
60	2073	0	$ -	0.1
Total		**5**	**$ 35,000**	**5**



5.3.2.2.f.x.3 Lifecycle Analysis Summary & Budget Allocation

Cable Chambers Profile			
5	Quantity	0.0	10 Year Historic Replacement/Installation Rate (Units/Year)
60	UL	0	Quantity Reaching Adjusted End of Life Over Forecast Period
20.4	Average Age of Population	$0	Total Capital Replacement Cost over Forecast Period
0.08	Ideal Equalized Annual Replacement Rate (Units/Yr)		Total Capital Refurbishment Cost over Forecast Period
34.0%	% TU Consumed	0.00	Average Replacements Per Year
42.3%	2019 % UL Consumed with no Reinvestment	$0	Average Annual Cost Per Year
		$583	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$0	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of the 5 Cable Chambers is not evenly distributed over one lifecycle period beginning in 2014. The lifecycle period is sparsely populated given the relative small asset count. FFPC adopted a UL of 60 years, and based on the average age of 20.4 years for the population, 34% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 42.3% by 2019. FFPC's long term target is to maintain %UL consumed at

50%. Over the last ten years, FFPC did not replace or install any cable chambers. The ideal average annual replacement rate is 0.08 chambers per year. Over the 2014 to 2018 forecast period, no cable chambers are projected to reach their AEOL, requiring replacement. As such, FFPC has not allocated any capital towards this asset class. Recent inspection finding have not found any deficiencies, and as such, no capital refurbishment costs have been allocated. The average annual reinvestment need for this asset class, assuming an evenly distributed population, is $583 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life.

5.3.2.2.f.x.4 Impact of Cable Chambers on DS Plan

As no expenditures are allocated towards this asset class over the planning period, Cable Chambers will not have an impact on the DS Plan with respect to cost requirements.

5.3.2.2.g. Remote SCADA

FFPC's transformer station is currently not equipped with a remote Supervisory Control and Data Acquisition (SCADA) system. As such, FFPC does not currently own any assets in this category. FFPC is planning on deploying a SCADA system over the 2014 to 2018 planning period, as part the Renewable Enabling Improvements planned at Fort Frances MTS. Please refer Section 5.4.3 for details regarding FFPC's planned Renewable Enabling Improvements (REG Investments).

5.3.2.2.h. General Plant Assets

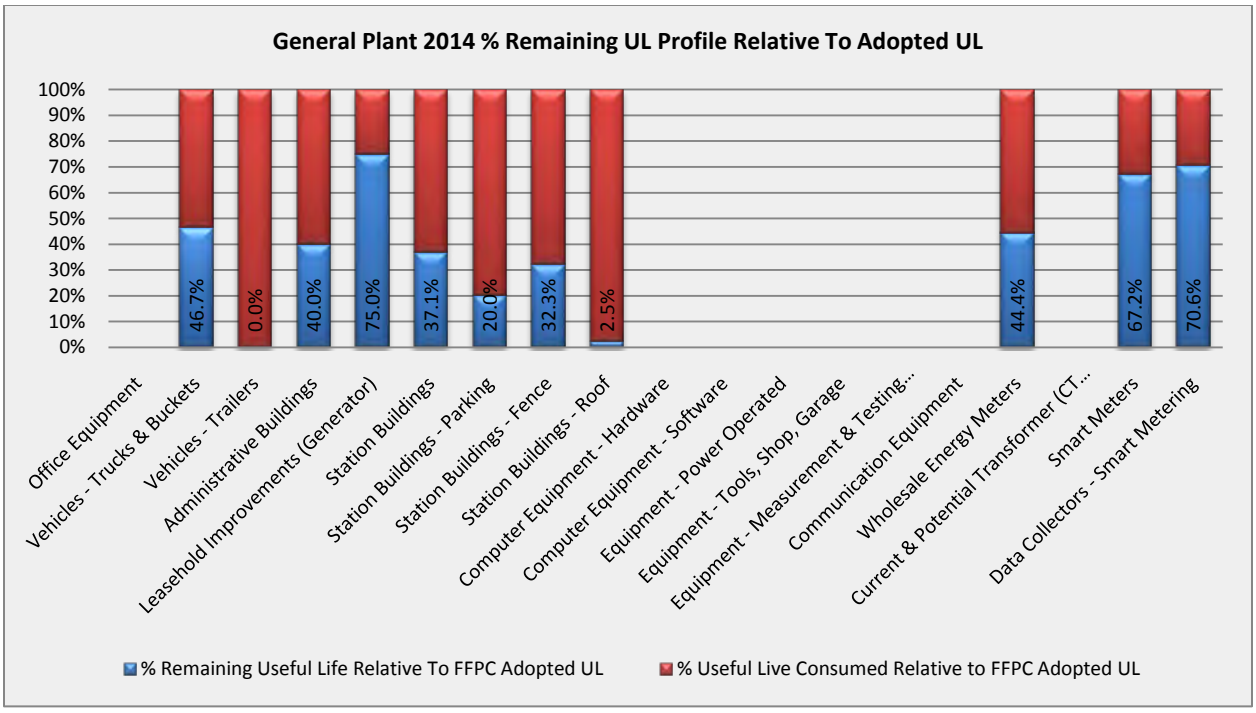
FFPC owns a significant amount of assets that are grouped under the parent group, "General Plant". FFPC does not own assets in all categories including Residential Energy Meters, Industrial/Commercial Energy Meters or in Repeaters - Smart Metering, and as such these categories have been omitted. The most significant assets are contained under the categories Vehicles, Administrative Buildings, Station Buildings and Smart Meters. FFPC has a relatively insignificant population of assets under the categories Office Equipment, Communications, Wholesale Energy Meters and Data Collectors - Smart Metering. FFPC is currently working on gathering detailed asset information for the Computer Equipment, Equipment, and Communication categories, such that age and condition profiles can be generated; however, at this time the information is not available. For asset classes where age and AEOL profiles are not known, FFPC based annual capital reinvestment needs on the total replacement value of the asset category, divided by the FFPC's adopted UL. For General Plant assets, the asset management process has only identified material capital reinvestment requirements for the asset group "Vehicles", over the 2014 to 2018 planning period. It is also worth noting that under the General Plant parent group, Vehicles and Smart Meters assets are by far the most expensive categories to sustain. On average, Vehicles and Smart Meters require approximately 8.6% and 7.0% respectively, of all annual lifecycle sustaining (replacement or refurbishment) capital investments.

5.3.2.2.h.i. General Plant Lifecycle Profile, Reinvestment Needs Boundaries & Reinvestment Summary

As per the Chapter 5 Filing Requirements guide, FFPC has relied on its newly developed Asset Management Process to collect, tabulate and assess information on physical assets, current and future system operating conditions, and FFPC's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus.

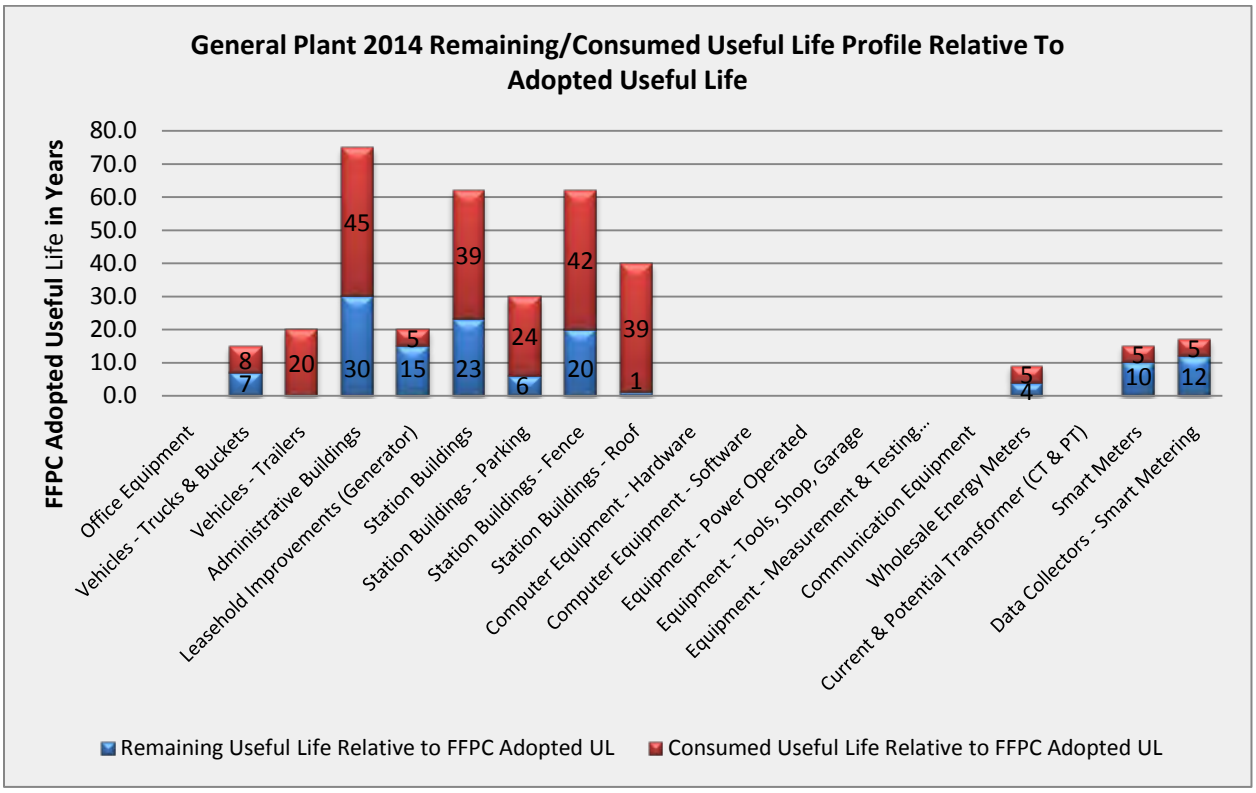
FFPC's asset management process has established a total asset replacement value of $24,379,821 for all existing assets managed, based on FFPC's replacement cost structure. Of this asset base, the replacement value of General Plant assets is estimated to be $2,969,374, which is approximately 26.1% of the total replacement value. Based on FFPC's adopted useful life values, the average annual reinvestment needed to keep pace with General Plant asset deterioration is $161,254. The overall % remaining useful life (relative to FFPC's adopted UL and replacement cost) is 48.3%. FFPC's long term objective is to maintain a 50% "Remaining UL" profile where possible, to smooth long term spending requirements. As such, FFPC has an optimal capital reinvestment budget allocation of $161,254 to sustain the lifecycle of General Plant assets. FFPC has allocated a total of $608,750 towards sustaining the lifecycle of General Plant, which equates to an average annual reinvestment of $121,750. The allocated capital is approximately 32% lower than the ideal average reinvestment need, to allow for more intensified expenditures towards more important asset classes. This will help to minimize the impact of the significant increase in overall capital expenditure requirements, as FFPC transitions out of its "maintenance mode" of operation, to a "capital rebuild mode" of operation.

The following graph illustrates the % UL Remaining profile of all General Plant asset categories, where age profiles are available as at the filing of this DS Plan.



Note: Age profiles are not yet available for the Equipment related categories.

The following graph illustrates the remaining and consumed years of all General Plant asset categories:



Note: Age profiles are not yet available for the Equipment related categories.

The following tables summarize planned capital expenditures over the 2014 to 2018 planning horizon, based on assets that were identified to be at the end of their useful service life, as per outputs of Step 4 of the asset management process. Capital expenditures driven by other investment drivers, such as the elimination of LTLT's, Customer Preference or Renewable Enabling Improvements, are not included in this summary. Of the total $3,522,205 in planned capital expenditures based on all investment drivers, $2,775,966 is driven by assets reaching the end of their useful service life (end of life of all assets managed including General Plant and over 50 kV Transformer Station assets). The table also illustrates the Useful Life and Reinvestment Need analysis for each asset category. Various reinvestment needs boundaries are illustrated representing various adoptions of useful service life philosophies, such as the "Kinectrics Report's" MIN UL, TUL, MAX UL, as well as FFPC's adopted UL.

FFPC Asset Summary, Useful Life Assessment, Investment Boundaries and Capital Budget Allocations

		Asset Details		FFPC Assets			Kinectrics Useful Life			Useful Life Assessment					Reinvestment Needs Assessment					Capital Budget Allocation		
Parent*	#	Category| Component | Type		Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to Kinectrics TUL	% Remaining Useful Life Relative Kinectrics TUL	Remaining Useful Life Relative to FFPC Adopted UL	% Remaining Useful Life Relative To FFPC Adopted UL	Total Replacement Cost of Asset Group	Average Annual Reinvestment Need Based on Kinectrics Min UL	Average Annual Reinvestment Need Based on Kinectrics TUL	Average Annual Reinvestment Need Based on Kinectrics Max UL	Average Annual Reinvestment Need Based on FFPC Adopted UL	Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2014 to 2018)	% of Total DS Plan Capital Expenditures
General Plant	1	Office Equipment		Unknown	Each	Unknown	*5*	*10.0*	*15*	15.0	Unknown	Unknown	Unknown	Unknown	$ 60,000	$ 12,000	$ 6,000	$ 4,000	**$ 4,000**	$ 15,000	$ 3,000	0.4%
	2	Vehicles	Trucks & Buckets	7	Each	8.00	*5*	*10.0*	*15*	15.0	2.0	20.0%	7.0	46.7%	$ 801,000	$ 160,200	$ 80,100	$ 53,400	**$ 53,400**	$ 328,000	$ 65,600	9.3%
			Trailers	2	Each	26.00	*5*	*12.5*	*20*	20.0	0.0	0.0%	0.0	0.0%	$ 75,000	$ 15,000	$ 6,000	$ 3,750	**$ 3,750**	$ 75,000	$ 15,000	2.1%
			Vans	N/A			*5*	*7.5*	*10*													
	3	Administrative Buildings		1	Each	45.00	*50*	*62.5*	*75*	75.0	17.5	28.0%	30.0	40.0%	$ 550,000	$ 11,000	$ 8,800	$ 7,333	**$ 7,333**	$ 65,000	$ 13,000	1.8%
	4	Leasehold Improvements (Generator)		1	Each	5.00	*20*	*20.0*	*20*	20.0	15.0	75.0%	15.0	75.0%	$ 86,122	$ 4,306	$ 4,306	$ 4,306	**$ 4,306**	$ -	$ -	0.0%
	5	Station Buildings	Station Buildings	2	Each	39.0	*50*	*62.5*	*75*	62.0	23.5	37.6%	23.0	37.1%	$ 368,375	$ 7,368	$ 5,894	$ 4,912	**$ 5,942**	$ 31,000	$ 6,200	0.9%
			Parking	1	Each	24.00	*25*	*27.5*	*30*	30.0	3.5	12.7%	6.0	20.0%	$ 5,000	$ 200	$ 182	$ 167	**$ 167**			0.0%
			Fence	1	Each	42.00	*25*	*42.5*	*60*	62.0	0.5	1.2%	20.0	32.3%	$ 22,500	$ 900	$ 529	$ 375	**$ 363**			0.0%
			Roof	2	Each	39.00	*30*	*30.0*	*30*	40.0	0.0	0.0%	1.0	2.5%	$ 30,000	$ 1,000	$ 1,000	$ 1,000	**$ 750**			0.0%
	6	Computer Equipment	Hardware	Unknown	Each	Unknown	*3*	*4.0*	*5*	5.0	Unknown	Unknown	Unknown	Unknown	$ 32,000	$ 10,667	$ 8,000	$ 6,400	**$ 6,400**	$ 35,500	$ 7,100	1.0%
			Software	Unknown	Each	Unknown	*2*	*3.5*	*5*	5.0	Unknown	Unknown	Unknown	Unknown	$ 76,000	$ 38,000	$ 21,714	$ 15,200	**$ 15,200**	$ -	$ -	0.0%
	7	Equipment	Power Operated	Unknown	Each	Unknown	*5*	*7.5*	*10*	7.0	Unknown	Unknown	Unknown	Unknown	$ 7,000	$ 1,400	$ 933	$ 700	**$ 1,000**	$ 30,500	$ 6,100	0.9%
			Stores	N/A			*5*	*7.5*	*10*													
			Tools, Shop, Garage Equip.	Unknown	Each	Unknown	*5*	*7.5*	*10*	10.0	Unknown	Unknown	Unknown	Unknown	$ 10,000	$ 2,000	$ 1,333	$ 1,000	**$ 1,000**	$ -	$ -	0.0%
			Measurement & Testing Equip	Unknown	Each	Unknown	*5*	*7.5*	*10*	8.0	Unknown	Unknown	Unknown	Unknown	$ 65,000	$ 13,000	$ 8,667	$ 6,500	**$ 8,125**	$ -	$ -	0.0%
	8	Communication	Towers	N/A			*60*	*65.0*	*70*													
			Wireless	Unknown	Each	Unknown	*2*	*6.0*	*10*	10.0	Unknown	Unknown	Unknown	Unknown	$ 9,600	$ 4,800	$ 1,600	$ 960	**$ 960**	$ -	$ -	0.0%
	9	Residential Energy Meters		N/A			*25*	*30.0*	*35*													
	10	Industrial/Commercial Energy Meters		N/A			*25*	*30.0*	*35*													
	11	Wholesale Energy Meters		2	Each	5.00	*15*	*22.5*	*30*	9.0	17.5	77.8%	4.0	44.4%	$ 18,000	$ 1,200	$ 800	$ 600	**$ 2,000**	$ -	$ -	0.0%
	12	Current & Potential Transformer (CT & PT)		479	Each	Unknown	*35*	*42.5*	*50*	40.0	Unknown	Unknown	Unknown	Unknown	$ 85,262	$ 2,436	$ 2,006	$ 1,705	**$ 2,132**	$ 12,500	$ 2,500	0.4%
	13	Smart Meters		3966	Each	4.92	*5*	*10.0*	*15*	15.0	5.1	50.8%	10.1	67.2%	$ 650,543	$ 130,109	$ 65,054	$ 43,370	**$ 43,370**	$ 16,250	$ 3,250	0.5%
	14	Repeaters - Smart Metering		N/A			*10*	*12.5*	*15*													
	15	Data Collectors - Smart Metering		7	Each	5.00	*15*	*17.5*	*20*	17.0	12.5	71.4%	12.0	70.6%	$ 17,972	$ 1,198	$ 1,027	$ 899	**$ 1,057**	$ -	$ -	0.0%
Totals															$ 2,969,374	$ 416,783	$ 223,946	$ 156,576	**$ 161,254**	$ 608,750	$ 121,750	17.3%

The following table summarizes FFPC's budgeted capital reinvestments, for each General Plant asset category over the 2014 to 2018 planning period. The planned reinvestments are all driven by the outputs of Step 4 of the asset management process, and as such they are allocated towards sustaining the lifecycle of existing assets. As previously mentioned, General Plant expenditures have been curtailed to minimize the impact of the increase in overall capital expenditure requirements, due to FFPC transitioning out of its maintenance mode to a capital rebuild mode.

		Asset Details		Capital Budget Allocation		
Parent*	**#**	**Category| Component | Type**		**Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation**	**Average Annual Capital Allocation (2014 to 2018)**	**% of Total DS Plan Capital Expenditures**
General Plant	1	Office Equipment		$ 15,000	$ 3,000	0.4%
	2	Vehicles	Trucks & Buckets	$ 328,000	$ 65,600	9.3%
			Trailers	$ 75,000	$ 15,000	2.1%
			Vans			
	3	Administrative Buildings		$ 65,000	$ 13,000	1.8%
	4	Leasehold Improvements (Generator)		$ -	$ -	0.0%
	5	Station Buildings	Station Buildings	$ 31,000	$ 6,200	0.9%
			Parking	$ -	$ -	0.0%
			Fence	$ -	$ -	0.0%
			Roof	$ -	$ -	0.0%
	6	Computer Equipment	Hardware	$ 35,500	$ 7,100	1.0%
			Software	$ -	$ -	0.0%
	7	Equipment	Power Operated	$ 30,500	$ 6,100	0.9%
			Stores			
			Tools, Shop, Garage Equip.	$ -	$ -	0.0%
			Measurement & Testing Equip	$ -	$ -	0.0%
	8	Communication	Towers			
			Wireless	$ -	$ -	0.0%
	9	Residential Energy Meters				
	10	Industrial/Commercial Energy Meters				
	11	Wholesale Energy Meters		$ -	$ -	0.0%
	12	Current & Potential Transformer (CT & PT)		$ 12,500	$ 2,500	0.4%
	13	Smart Meters		$ 16,250	$ 3,250	0.5%
	14	Repeaters - Smart Metering				
	15	Data Collectors - Smart Metering		$ -	$ -	0.0%
Totals				$ 608,750	$ 121,750	17.3%

5.3.2.2.h.ii. Office Equipment

FFPC owns various types of office equipment which are required to transact business. Assets owned include items such as a media centre (photocopier), fax machine, labeler and shredder. FFPC plans on incurring costs in this category during the period 2014 to 2018; however, they are far below the materiality threshold, and as such they have not been detailed. The single largest planned expense under this category is the replacement of a media centre in 2017.

5.3.2.2.h.iii. Vehicles

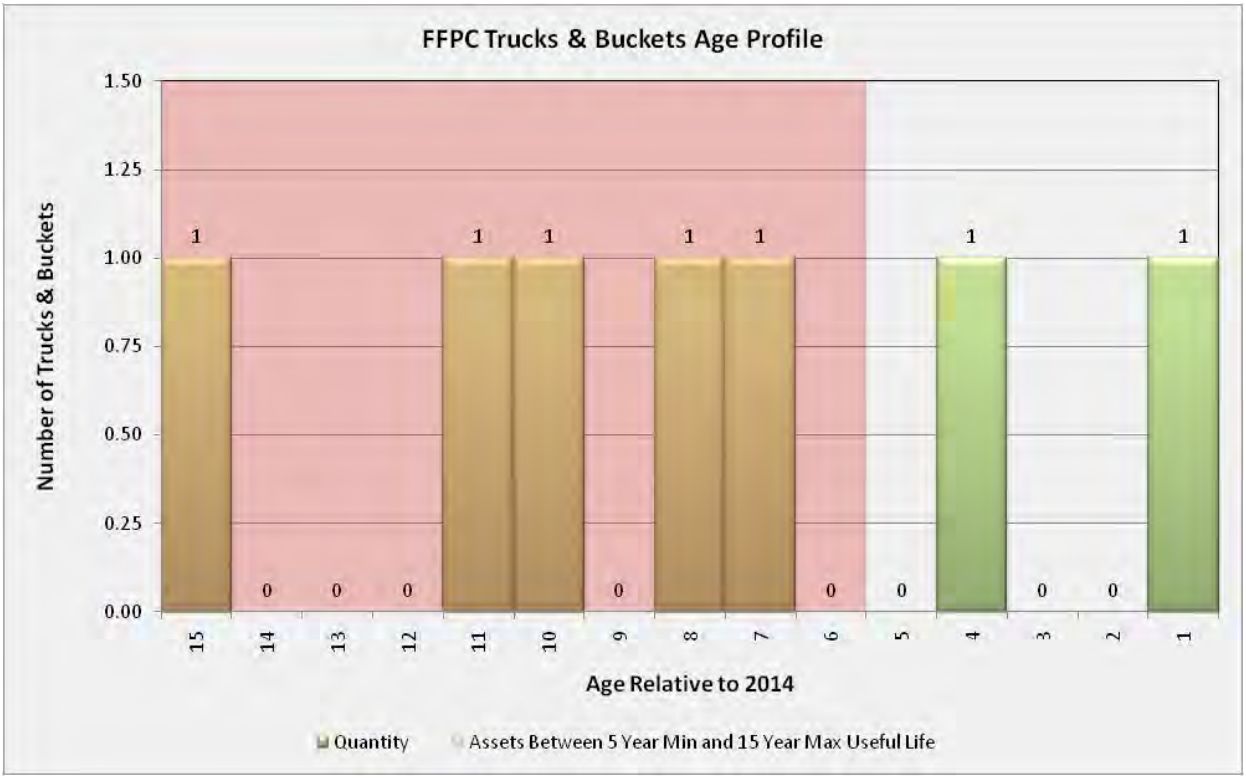
FFPC owns and operates a fleet of seven trucks and two trailers that support all maintenance, operations and capital activities. FFPC relies on one Digger Derrick Truck, one Double Bucket Truck, one Single Bucket Truck, one Dump Truck (1 Ton truck) and two half-ton trucks to manage its electrical distribution system and customer base. FFPC also owns one Chipper Trailer and one Cable Reel Trailer.

It is very important to FFPC's overall operation that all vehicles remain in good working condition, as FFPC does not have redundant units to rely upon. As such, FFPC recently invested in a shop expansion that allows for all major fleet vehicles to be parked indoors. The expansion has greatly enhanced the reliability of FFPC's fleet vehicles, especially during the cold winter months. Hydraulic systems are kept warm and responsive, when called upon for duty.

5.3.2.2.h.iii.1 Vehicles Age Profile Relative to Useful Life Period

FFPC has adopted the Maximum Useful Life of 15 years for its Trucks & Buckets, and the Maximum Useful Life of 20 years for its trailers, as per the "Kinectrics Report". As previously mentioned, the Vehicles category is the only category under General Plant requiring material capital reinvestment over the period 2014 to 2018, based on the outputs of the asset management process. The following tables and graphs represent the age profile of FFPC's Trucks & Buckets and Trailers respectively, with respect to their Useful Life relative to the adopted MAX UL established in the Kinectrics Report.

Trucks & Buckets Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 15 Year Max UL)**	**Quantity**
1999	15	2014	1
2000	14	2015	0
2001	13	2016	0
2002	12	2017	0
2003	11	2018	1
2004	10	2019	1
2005	9	2020	0
2006	8	2021	1
2007	7	2022	1
2008	6	2023	0
2009	5	2024	0
2010	4	2025	1
2011	3	2026	0
2012	2	2027	0
2013	1	2028	1
Total			**7**



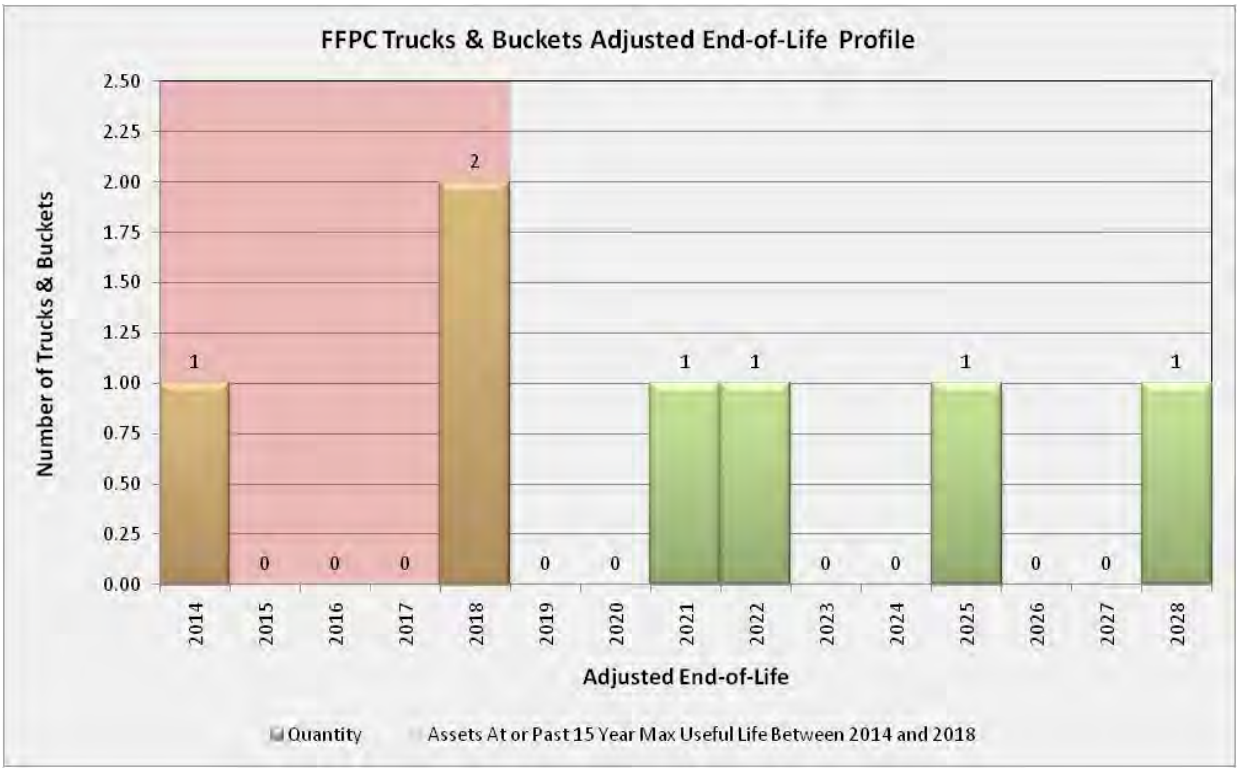
Trailers Age Profile (Relative to 2014 - Based on July 2013 Data)			
In Service Year	**Age**	**End-of-Life (Based on 20 Year Max UL)**	**Quantity**
1978	36	1998	1
1979	35	1999	0
1980	34	2000	0
1981	33	2001	0
1982	32	2002	0
1983	31	2003	0
1984	30	2004	0
1985	29	2005	0
1986	28	2006	0
1987	27	2007	0
1988	26	2008	0
1989	25	2009	0
1990	24	2010	0
1991	23	2011	0
1992	22	2012	0
1993	21	2013	0
1994	20	2014	0
1995	19	2015	0
1996	18	2016	0
1997	17	2017	0
1998	16	2018	1
1999	15	2019	0
2000	14	2020	0
2001	13	2021	0
2002	12	2022	0
2003	11	2023	0
2004	10	2024	0
2005	9	2025	0
2006	8	2026	0
2007	7	2027	0
2008	6	2028	0
2009	5	2029	0
2010	4	2030	0
2011	3	2031	0
2012	2	2032	0
2013	1	2033	0
Total			2



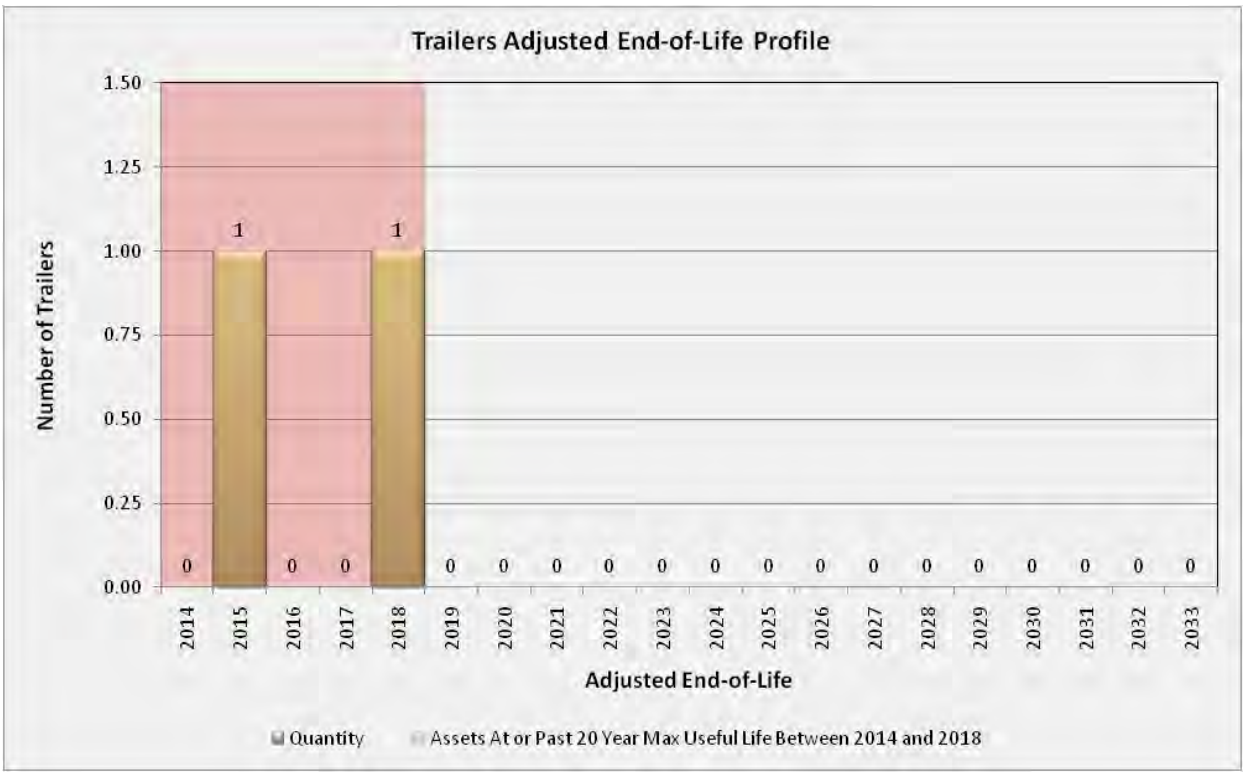
5.3.2.2.h.iii.2 Vehicles Adjusted End-of-Life Profile Relative to Adjusted End-of-Life Projections

FFPC performs routine inspections on all of its fleet vehicles, as well as any necessary maintenance is performed annually, during the mechanical, dielectric, and emissions inspection and testing processes. As previously discussed, FFPC's core fleet vehicles are all parked indoors and out of the elements when not in use. As such, the fleet vehicles are expected to remain reliable, and safe for use up to their recommended maximum useful life. FFPC has assigned Adjusted End-of-Life values corresponding to the Maximum Useful Life values contained in the "Kinectrics Report". As such, Trucks & Buckets are expected to have a useful life of 15 years, and trailers are expected to have a useful life of 20 years. The following tables and graphs illustrate FFPC's anticipated replacement schedule according to Adjusted End-of-Life Projections, based on FFPC's asset management process. Note that large fleet vehicles, such as double bucket trucks, have a typically delivery time of one year. As such, they are planned and budgeted for one year in advance to ensure that they are received in a timely manner.

Truck & Buckets Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**1**	**$ 38,000**	**0.5**
2	**2015**	**0**	**$ -**	**0.5**
3	**2016**	**0**	**$ -**	**0.5**
4	**2017**	**0**	**$ -**	**0.5**
5	**2018**	**2**	**$ 290,000**	**0.5**
6	2019	0	$ -	0.5
7	2020	0	$ -	0.5
8	2021	1	$ 42,000	0.5
9	2022	1	$ 65,000	0.5
10	2023	0	$ -	0.5
11	2024	0	$ -	0.5
12	2025	1	$ 246,000	0.5
13	2026	0	$ -	0.5
14	2027	0	$ -	0.5
15	2028	1	$ 120,000	0.5
Totals		**7**	**$ 801,000.00**	**7**



Trailers Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**0**		**0.1**
2	**2015**	**1**	**$ 50,000**	**0.1**
3	**2016**	**0**		**0.1**
4	**2017**	**0**		**0.1**
5	**2018**	**1**	**$ 25,000**	**0.1**
6	2019	0		0.1
7	2020	0		0.1
8	2021	0		0.1
9	2022	0		0.1
10	2023	0		0.1
11	2024	0		0.1
12	2025	0		0.1
13	2026	0		0.1
14	2027	0		0.1
15	2028	0		0.1
16	2029	0		0.1
17	2030	0		0.1
18	2031	0		0.1
19	2032	0		0.1
20	2033	0		0.1
Totals		**2**	**$ 75,000.00**	**2**



5.3.2.2.h.iii.3 Lifecycle Analysis Summary & Budget Allocation

Trucks & Buckets Profile			
7	Quantity	0.4	10 Year Historic Replacement/Installation Rate (Units/Year)
15	UL (Adopted)	3	Quantity Reaching Adjusted End of Life Over Forecast Period
8.0	Average Age of Population	$328,000	Total Capital Replacement Cost over Forecast Period
0.47	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
53.3%	% UL Consumed	0.60	Average Replacements Per Year
86.7%	2019 % UL Consumed with no Reinvestment	$65,600	Average Annual Cost Per Year
		$53,400	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$328,000	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 7 Trucks & Buckets is not evenly distributed over one lifecycle period beginning in 2014. The population by nature is not densely populated, given the relatively low asset count over the lifecycle period. Therefore replacement needs are sporadic and not very uniform by nature. As such, expenditure needs are somewhat sporadic. FFPC adopted a UL of 15 years, and based on the average age of 8 years for the population, 53.3% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 86.7% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC replaced an average of 0.4 vehicles per year, which is slightly lower than the ideal average annual replacement rate of 0.47 trucks & buckets per year. Over the 2014 to 2018 forecast period, three vehicles will reach or surpass their UL of 15 years; however, a total of four will reach or surpass their AEOL. The total estimated capital replacement cost is $328,000 and no capital refurbishments are projected to be required. The average annual replacement rate is 0.6 vehicles per year, and the average total annual reinvestment cost is $65,600 per year. The average annual reinvestment need for this asset class, assuming a dense and evenly distributed population is $53,400 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated $328,000 toward capital replacements and has not allocated any capital for refurbishments. This is slightly higher than the ideal average annual reinvestment need; however, it is aligned with FFPC's objective of keeping pace with the rate of deterioration.

Trailers Profile			
2	Quantity	0.0	10 Year Historic Replacement/Installation Rate (Units/Year)
20	UL (Adopted)	2	Quantity Reaching Adjusted End of Life Over Forecast Period
26.0	Average Age of Population	$75,000	Total Capital Replacement Cost over Forecast Period
0.10	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
130.0%	% UL Consumed	0.40	Average Replacements Per Year
155.0%	2019 % UL Consumed with no Reinvestment	$15,000	Average Annual Cost Per Year
		$3,750	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$75,000	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

The age distribution of the population of 2 trailers is not evenly distributed over one lifecycle period beginning in 2014. The population is not densely populated given the low asset count over the lifecycle. Therefore replacement needs are sporadic and not very uniform by nature. As such, expenditure needs may vary from year to year. FFPC adopted a UL of 15 years, and based on the average age of 26 years for the population, 130% UL has been consumed. If FFPC was not to reinvest into this asset class, the percentage of UL consumed increases to 155% by 2019. FFPC's long term target is to maintain %UL consumed at 50%. Over the last ten years, FFPC did not replace or acquire any trailers. The ideal average annual replacement rate of trailers is 0.1 per year. Over the 2014 to 2018 forecast period, one trailer will reach and the other has long surpassed its UL of 20 years. The total estimated capital replacement cost is $75,000 and no capital refurbishments have been identified (trailer must be outright replaced). The average annual replacement rate is 0.4 trailers per year, and the average total annual reinvestment cost is $15,000 per year. The average annual reinvestment need for this asset class, assuming a dense and evenly distributed population, is $3,750 per year, based on the replacement cost of one lifecycle (cost to replace entire asset class) divided by FFPC's adopted useful life. FFPC has allocated $75,000 toward capital replacements and has not allocated any capital towards refurbishment. This is slightly higher than the ideal average annual reinvestment need; however, it is aligned with FFPC's objective of keeping pace with the rate of deterioration.

5.3.2.2.h.iii.4 Impact of Trucks & Buckets and Trailers on DS Plan

The planned reinvestment into vehicles has a material impact on FFPC's DS Plan. The total capital replacement cost of $328,000 for the Trucks & Buckets represents 9.3% of the total planned capital expenditures over the 2014 to 2018 planning horizon. The total replacement cost of $75,000 for trailers represents 2.1% of the total planned capital expenditures over the planning horizon

5.3.2.2.h.iv. Administrative Buildings

FFPC owns an Operations Centre located on 939 Wright Avenue in Fort Frances, Ontario. The centre is used to house fleet vehicles, various inventory items such as poles, transformers, gravel, as well as it is the work centre for the line crew and General Superintendent. The centre was originally constructed in 1969 and an addition was added in 2009. The addition allowed for all core fleet vehicles to be parked inside to minimize their deterioration, as well as to ensure they are fit for duty during the cold winter months. FFPC does not plan on incurring any significant expense in this category during the period 2014 to 2018, and as such detailed componentized life projections are not included.

5.3.2.2.h.v. Leasehold Improvements

In 2009 FFPC purchased and installed a backup generator for its main office located on 320 Portage Avenue in Fort Frances Ontario. The generator allows FFPC to function during power outages and was a much needed emergency preparedness improvement. Prior to this improvement, core functionality including building heat was not operable during power outages. FFPC is a member of the Community Emergency Control Group, who's head quarters are now also located at 320 Portage Avenue. FFPC does not have any expenditures planned for this category during the period 2014 to 2018.

5.3.2.2.h.vi. Station Buildings

Transformer station Fort Frances MTS has two "Station Buildings". The first building "T1 Control Building", houses the metal clad switchgear for feeders that are normally fed from Transformer T1. The building is a 1972 metal prefab building. The second building is a block brick building that was constructed in 1978 to house Transformer T2 metal clad switchgear, as well as all other station services such as DC Battery Systems, tie-breaker controls, station independent breaker controls, as well as a civil work area. Both station buildings are inspected monthly as part of FFPC maintenance inspection program. The buildings are found to be in good health relative to their age. All supporting components such as the parking area, access gates, roofs and fencing are currently all in good health and are not expected to require any material investments over the 2014 to 2018 planning period. FFPC is planning for one material investment in 2015. Transformer T1 and T2 are located in close proximity of one another, and as such a massive failure of one could result in damage to the other. FFPC's insurance carrier has recommended that a fire/blast barrier be installed in between the two transformers, such that any airborne debris or flames are contained in the event of a massive failure.

5.3.2.2.h.vii. Computer Equipment

FFPC currently owns ten computer stations that are located in either the main office or operations centre. FFPC has adopted the maximum useful life of 5 years for these stations. All stations are setup with base software such as Virus Protection, and core office programs such as Microsoft Office. Some stations are then loaded with additional functionality such as GIS or access to Customer Service Software depending on the user. FFPC also owns various other computing hardware such as printers,

network hubs and docking stations. FFPC also owns several higher value business software solutions such as its GIS system. FFPC plans to keep its fleet of computing hardware and software up to date over the 2014 to 2018, and as such has annual planned investments; however the combined total of all investments in this category are far below the materiality threshold.

5.3.2.2.h.viii. Equipment

FFPC owns and relies on various general equipment in order to conduct its business. Power operated tools range from chainsaws, lawnmowers and weed-eaters to drill presses, hammer drills and saws-alls. While hand tools range from trade specific line tools to general tools such as hammers, shovels, screw-drivers or sockets. FFPC plans to keep its fleet of equipment in good condition and to replace items as they fail. As such, FFPC plans on incurring annual expenses in this category during the period 2014 to 2018; however, the combined total of all expenses in this category are far below the materiality threshold.

5.3.2.2.h.ix. Communication

FFPC utilizes a meridian telephone system, cellular phones, two-way radios, as well as data lines and communication packages (long distance telephone calls, fax lines, internet data packages etc) to conduct its business. FFPC plans on incurring annual expenses in this category to keep equipment current and in good health. During the period 2014 to 2018 FFPC does not have any material investments planned in this category, and as such only immaterial annual costs are planned.

5.3.2.2.h.x. Wholesale Metering

FFPC's transformer station Fort Frances MTS contains two wholesale metering points, one on each of the secondary side of the two station power transformers. Both metering seals expired in 2009 and as such the units were replaced in 2009. FFPC does not foresee the need to replace or upgrade any of its wholesale metering assets during the period 2014 to 2018. As such, FFPC does not have any expenditures planned in this category over the planning period.

5.3.2.2.h.xi. Smart Meters

As per the provincial smart meter mandate, FFPC replaced its entire meter population with smart meters during the years 2009 to 2011. To the best of FFPC's knowledge, the useful life of the smart meters is governed by Measurement Canada, as it has the authority to govern meter seal periods. All of FFPC's smart meters purchased have a 10 year seal. The "Kinectrics Report" established a useful life range of 5 to 15 years. For the purpose of this application FFPC has assigned an Adjusted End-of-Life value of 15 to its smart meter population. This is aligned with FFPC's depreciation. If however, operating smart meters beyond their 10 year seal period is a Measurement Canada violation, FFPC will be forced to replace its entire smart meter population according to a 10 year lifecycle, as opposed to a

15 year cycle. The reduced life expectancy would increase FFPC's average annual replacement cost for Smart Meters from $43,370 to $65,064, which would be equivalent to approximately half of FFPC's capital pole replacement program.

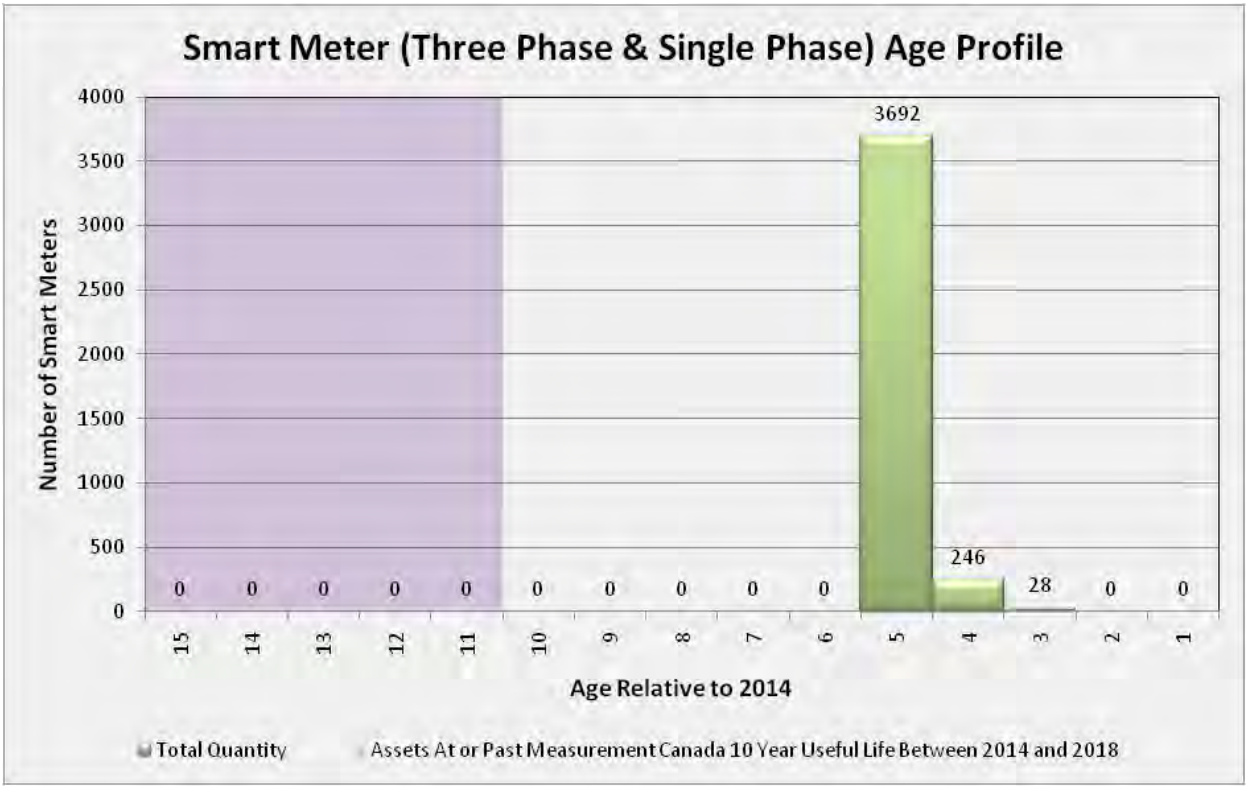
FFPC seeks OEB guidance with respect to lifecycle planning for smart meters, specifically whether meters will be legally allowed to remain in operation from years 10 through 15 with respect to their seal expiry as governed by Measurement Canada. FFPC notes that this determination will have a significant impact on FFPC's work planning, amortization cost and budget considerations.

It is worth noting that a 10 year seal expiration date would correspond to FFPC's 2019 planning year and beyond.

5.3.2.2.h.xi.1 Smart Meter Age Profile Relative to Maximum Useful Life

The following table and graph illustrate FFPC's smart meter age profile relative to the 15 year maximum useful life established in the "Kinectrics Report". It is again important to note that the best of FFPC's knowledge meter seals expire after 10 years as per current Measurement Canada requirements.

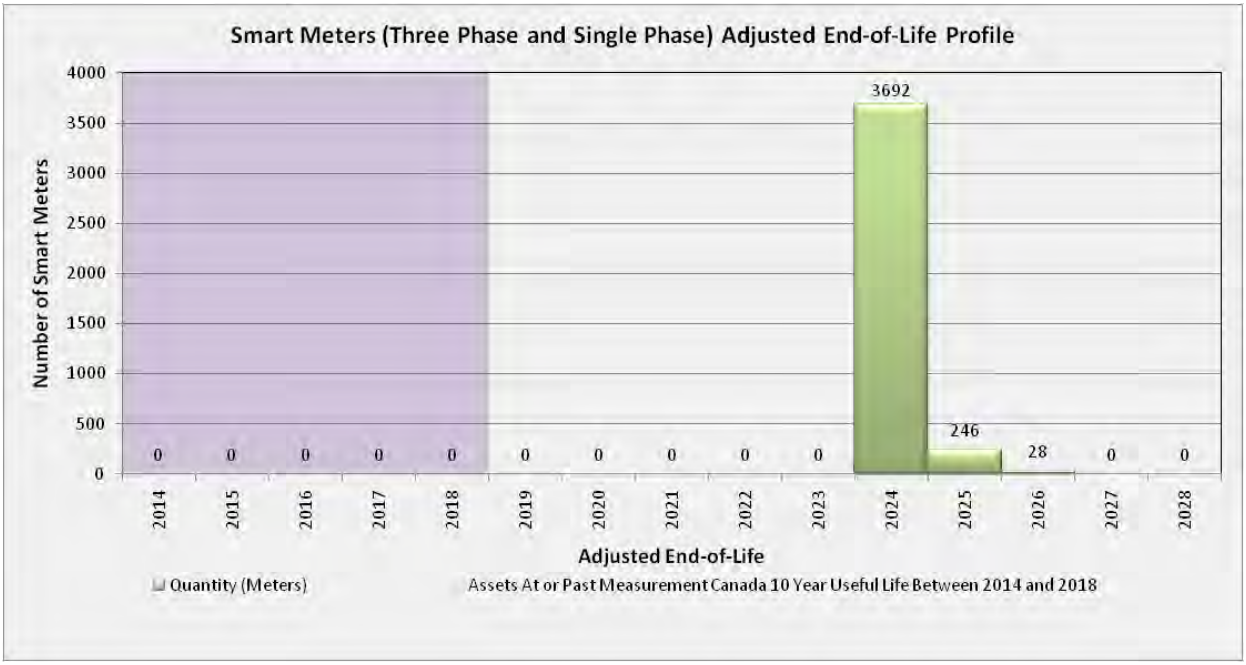
Smart Meter Age Profile (Relative to 2014 - Based on July 2013 Data)					
In Service Year	**Age**	**End-of-Life (Based on 15 Year Max UL)**	**Single Phase**	**Three Phase**	**Total Quantity**
1999	15	2014	0.0	0.0	0
2000	14	2015	0.0	0.0	0
2001	13	2016	0.0	0.0	0
2002	12	2017	0.0	0.0	0
2003	11	2018	0.0	0.0	0
2004	10	2019	0.0	0.0	0
2005	9	2020	0.0	0.0	0
2006	8	2021	0.0	0.0	0
2007	7	2022	0.0	0.0	0
2008	6	2023	0.0	0.0	0
2009	5	2024	3616.0	76.0	3692
2010	4	2025	44.0	202.0	246
2011	3	2026	20.0	8.0	28
2012	2	2027	0.0	0.0	0
2013	1	2028	0.0	0.0	0
Totals			**3680**	**286**	**3966**



5.3.2.2.h.xi.2 Smart Meter Adjusted End-of-Life Projections

FFPC has adopted a Maximum Useful Life of 15 years for its smart meter population, as per the "Kinectrics Report". FFPC has aligned it Adjusted End-of-Life dates accordingly. It is again important to note that Measurement Canada seal periods expire after 10 years, and if FFPC had to comply with this requirement all of FFPC's meters would have an Adjusted End-of-Life of 10 years. The following table and graph illustrate FFPC's Adjusted End-of-Life Projections according to FFPC's asset management plan.

Smart Meters Adjusted End-of-Life Profile Based of Asset Management Process (Relative to 2014 - Based on July 2013 Data)				
Lifecycle Year	**Adjusted End-of-Life Year**	**Quantity (Meters)**	**Replacement Cost**	**Ideal Evenly Distributed Annual Replacement Rate**
1	**2014**	**0**	**$ -**	**264.4**
2	**2015**	**0**	**$ -**	**264.4**
3	**2016**	**0**	**$ -**	**264.4**
4	**2017**	**0**	**$ -**	**264.4**
5	**2018**	**0**	**$ -**	**264.4**
6	2019	0	$ -	264.4
7	2020	0	$ -	264.4
8	2021	0	$ -	264.4
9	2022	0	$ -	264.4
10	2023	0	$ -	264.4
11	2024	3692	$ 605,599	264.4
12	2025	246	$ 40,351	264.4
13	2026	28	$ 4,593	264.4
14	2027	0	$ -	264.4
15	2028	0	$ -	264.4
Totals		**3966**	**$ 650,542.98**	**3966**



5.3.2.2.h.xii. Data Collectors - Smart Meters

FFPC's Elster Energy Axis Smart Metering System, utilizes Data Collectors to backhaul smart meter data back to its central server called the Master Application Server (MAS). FFPC requires the use of six active and one spare Data Collector, to administer its smart meter network throughout its entire licensed distribution service territory. FFPC has adopted the Maximum Useful Life of 20 years for these units, as per the "Kinectrics Report". FFPC performs routine inspections of the units, and services them upon notification of error codes, which imply improper operation. FFPC does not plan on incurring any material expenses in this category during the 2014 to 2018 period.

5.3.3 Asset lifecycle optimization policies and practices

Over the 2014 to 2018 planning horizon, approximately two-thirds of all planned capital investments are driven by "system renewal", specifically due to assets reaching their end-of-useful service life. FFPC's asset management process is designed to project the end of service lives for individual assets and to quantify the corresponding impact/risk associated with failure. FFPC's methodology generates end-of-life dates for individual assets (due to high probability of failure), taking into consideration the age, and condition of assets as quantified by inspection and condition testing results. FFPC is working towards formally developing individual health index algorithms for all major asset categories, which will be formally assigned to each individual asset owned. The health indexes will essentially generate the order in which assets are expected to fail. As such, informed decision can be made to prioritize asset replacements based on other variables such as impact of failure.

FFPC performs detailed inspections, as well as condition tests, on all major asset categories where practical. Refer to Appendix 4 "Maintenance Inspection Program" for details. The results of inspections and condition tests are used to quantify the amount of asset deterioration. As such, the degree of asset

deterioration is a key input to projecting equipment longevity as well as the expected date of failure. The date on which an asset is predicted to fail is termed as an asset's "Adjusted End-of-Life" (AEOL) date, as per FFPC's asset management process. By default AEOL's are aligned with TUL values according to the "Kinectrics Report". Favourable inspection and condition testing results will extend an asset's AEOL date beyond the TUL and alternately unfavourable inspection and condition testing results will shorten an asset's AEOL with respect to its TUL. It is important to note that adjusted end-of-life projections are more meaningful as assets approach their TUL, as opposed during their early years of service. The TUL stage of an assets lifecycle is the critical time at which investment decisions must be made. The decision could be to do nothing, replace, refurbish, decommission or develop the asset.

FFPC's Adjusted End-of-Life profiles essentially govern lifecycle related investments. FFPC's long term goal is to normalize unevenly distributed asset populations, thereby smoothing future expenditure requirements, while at the same time replacing assets proactively just before reaching their point of failure. FFPC's "just in time" proactive asset replacement strategy allows for replacements to be conducted in a coordinated and planned manner, as opposed to under emergency repair circumstances. Emergency repair circumstances often add significant unnecessary expense such as overtime rates of pay or minimum crew callout durations, as well as they often require the use of more expensive equipment such as vacuum trucks to complete the job safely.

FFPC has also aligned the life cycles of various asset classes such that multiple asset classes can be changed at the same time. For example, FFPC has e adopted a useful of 80 year for Underground Foundations, as opposed to the 55 year TUL suggested in the "Kinectrics Report". The 80 year life cycle will enable FFPC to replace the foundation every second time that the transformer which is mounted onto it is replaced, as FFPC has adopted a 40 year useful life for transformers as per the 40 TUL in the "Kinectrics Report". Similarly FFPC has adopted a useful life (UL) of 80 years for all underground ducts, including cement encased ducts.

Furthermore, FFPC has adopted several Maximum Useful Life values as per the "Kinectrics Report" for various asset classes, as the longer service life better reflects FFPC operating conditions and environment. For example, FFPC has adopted the Maximum Useful Life of 20 years for Trucks and Buckets. This is due to FFPC expanding its Operations Centre to house fleet vehicles indoors, to minimize the amount of deteriorate due to unnecessary exposure the extreme weather. The probability of equipment failure is thereby also greatly reduced).

5.3.3.1 Potential Asset Refurbishment Summary

FFPC evaluates the feasibility of refurbishing assets on an asset specific basis depending on circumstances. Only a portion of FFPC's asset base is conducive to being refurbished or partially refurbished. Some asset classes; however, must be outright replaced in their entirety. The following table summarizes whether or not particular asset groups are conducive to refurbishment in FFPC's experience. A detailed explanation of the rationale follows the table.

Asset Refurbishment Summary Table					
Asst Category		**Asset Details**			**Refurbishment Considered?**
Parent*	**#**	**Category| Component | Type**			**Yes / No**
OH	1	Fully Dressed Wood Poles	Overall		Yes
			Cross Arm	Wood	N/A
				Steel	N/A
	4	OH Line Switch			Yes
	8	OH Conductors	Primary Conductor		No
			Secondary Conductor		No
	9	OH Transformers			No
TS & MS	12	Power Transformers	Overall		Yes
			Bushing		Yes
			Tap Changer		Yes
	13	Station Service Transformer			No
	15	Station DC System	Overall		Yes
			Battery Bank		Yes
			Charger		Yes
	16	Station Metal Clad Switchgear	Overall		Yes
			Removable Breaker		Yes
	17	Station Independent Breakers			Yes
	18	Station Switch			Yes
	19	Electromechanical Relays			No
	21	Digital & Numeric Relays			No
	22	Rigid Busbars			No
	23	Steel Structure			Yes
UG	29	Primary TR XLPE Cables in Duct			Yes
	31	Secondary Cables Direct Buried			No
	34	Pad-Mounted Transformers	Single Phase		No
			Three Phase		No
	36	UG Foundation			No
	40	Ducts			No
	41	Concrete Encased Duct Banks			No
	42	Cable Chambers			No
General Plant	1	Office Equipment			Yes
	2	Vehicles	Trucks & Buckets (7 Units)		Yes
			Trailers (2 Units)		Yes
			Vans		N/A
	3	Administrative Buildings			Yes
	5	Station Buildings	Station Buildings (2 Buildings)		Yes
			Parking		Yes
			Fence		Yes
			Roof		Yes
	6	Computer Equipment	Hardware		Yes

			Software	No
	7	Equipment	Power Operated	No
			Stores	No
			Tools, Shop, Garage Equip.	Yes
			Measurement & Testing Equip	No
	8	Communication	Towers	N/A
			Wireless	No
	11	Wholesale Energy Meters		No
	12	Current & Potential Transformer (CT & PT)		No
	13	Smart Meters		No
	15	Data Collectors - Smart Metering		Yes

5.3.3.2 Prioritization of Individual Asset Replacements or Refurbishments

FFPC uses the following priority tree to determine the importance of individual assets, for the purpose of ranking the importance of necessary individual asset replacements or refurbishments.

1. Asset failure poses imminent shock or safety hazard to the general public or to employees
2. Asset failure impacts entire distribution system
3. Asset failure impacts one or more feeders
4. Asset failure impacts large section of feeder
5. Asset failure impacts essential services
6. Asset failure impacts critical customers
7. Asset failure impacts multiple residential units or businesses
8. Asset failure impacts single residential unit or business
9. Asset failure does not impact customers

5.3.3.3 Overhead Distribution Assets Optimization Policies and Practices

5.3.3.3.a. Fully Dressed Wood Poles

FFPC replaces wood poles individually as per the findings of FFPC's overhead plant inspection and condition testing process, which is an integral part of FFPC's asset management process. As such, FFPC continually focuses on replacing the worst poles, as opposed to replacing sections of feeders where some poles would still be relatively good health. As part of the replacement process, FFPC inspects all components to see if any are fit for reuse. As FFPC has experienced considerable premature failures of wood poles due to flaws in the manufacturers treatment process, FFPC has been able to avoid unnecessary expense through the reuse of "like new" components. The most common components fit for reuse are the metal standoff brackets which are expected to last more than two full lifecycles of the wood poles to which they are affixed. It is important to note; however, that in order for any minor component to be deemed fit for reuse, it must be inspected thoroughly to ensure that no defects exist. Furthermore, any major component must also be condition tested to verify that it is fit for reuse.

5.3.3.3.b. Overhead Line Switches

FFPC currently utilizes three types of overhead line switches that are grouped into this category. FFPC has manual gang operated sectionalizing switches, inline paralleling switches, as well as inline fused switches, all of which are three phase switch settings. FFPC performs routine inspections of all overhead switches according to its overhead plant inspection process. The most common indentified deficiency is insulator degradation. FFPC believes that it is worthwhile to extend the life of switches with minor refurbishments such as insulator replacements, as they are easy to do, as well as inexpensive.

5.3.3.3.c. Overhead Conductors

FFPC is not aware of any practical way in which overhead primary or secondary conductors can be refurbished. For jacketed cables, silicon injection technology allows for refurbishment; however, the practical application would be for underground primary cables. FFPC performs routine inspections of all of its overhead conductors according to its maintenance inspection problem. Any small deficiencies such as excess sag or poor terminations are repaired under FFPC's maintenance problem.

5.3.3.3.d. Overhead Transformers

FFPC does not refurbish overhead transformers and generally speaking transformers do not require maintenance. Historically transformers were run to failure, or alternately, were replaced in poorly accessible areas (back lot construction) at the same time that the wood poles to which they were mounted to were replaced. FFPC's new asset management approach is to transition to a just-in-time replacement approach, such that replacements are conducted under planned and coordinated circumstances, as opposed to under emergency repair circumstances. Factors that influence transformer replacements include the relative health of the transformer as determined by FFPC's asset management process, as well as the impact of failure. The pole mounted transformer population is not evenly distributed and as such, FFPC will face the foot of a "tidal wave" beginning in the 2014 to 2018 planning period. This further necessitates that FFPC ramp up its replacement program, beginning with replacements that are found to have the lowest health and highest impact of failure. FFPC's asset management process is utilized to prioritize the order in which individual transformers require replacing.

5.3.3.4 Transformer Station Lifecycle Optimization Policies and Practices

FFPC plans on sustaining its transformer station Fort Frances MTS such that it will achieve, or possibly surpass, its maximum useful life as dictated by core station components. As per the "Kinectrics Report", the majority of major station components such as Power Transformers, Metal Clad Switchgear and Station Switches, all have a maximum useful service life of 60 years. Accordingly, FFPC has set an end of service life target date of 2034 for Fort Frances MTS. The availability of replacement parts has become a known issue for some components, as the types of assets are no longer commonly used in the industry.

FFPC has retained the services of Siemens Canada to perform annual maintenance inspections and asset condition testing of all major station components. All major components have been assigned to a three year maintenance schedule and asset condition assessments are performed annually, due to the criticality of the station.

The following maintenance, testing and inspection schedule has been applied as per the recommendation of Siemens Canada:

Year 1 Inspection, Maintenance & Condition Analysis:

- OCB testing
- Relay testing
- Battery banks testing
- Yearly oil sampling (all assets containing oil - T1, T2 & OCB's)

Year 2 Inspection, Maintenance & Condition Analysis:

- Transformer T1 and associated equipment (tap changer, arrestors), T1 15 kV Breakers
- Battery banks testing
- Yearly oil sampling (all assets containing oil- T1, T2 & OCB's)

Year 3 Inspection, Maintenance & Condition Analysis:

- Transformer T2 and associated equipment (tap changer, arrestor), T2 15 kV Breakers
- Battery banks testing
- Yearly oil sampling (all - T1, T2 & OCB's)

The following schedule will be applied for the period 2014 to 2018

Year	Asset Management Schedule
2014	Year 1 Schedule
2015	Year 2 Schedule
2016	Year 3 Schedule
2017	Year 1 Schedule
2018	Year 2 Schedule

5.3.3.4.a. Power Transformers

Power transformers by nature require ongoing maintenance and are conducive to being partially refurbished. Over the last few years, FFPC has replaced and repaired components that have a shorter lifecycle relative to the transformer core. For example, FFPC has replaced all lighting arrestors, and has performed an overhaul of the automatic tap changers. FFPC has also reconditioned the oil and performed major maintenance repairs such as replacing the cooling fin gaskets. As previously mentioned, FFPC's strategy is to continue with necessary ongoing maintenance activities, as well as

necessary refurbishments of smaller components, such that the power transformers will achieve their maximum suggested service life of 60 years. Over the 2014 to 2018 planning horizon, FFPC will pay special attention to monitoring the condition of the bushings as they are still original, however conditions testing has not shown signs of deterioration. Overall, the 2013 maintenance inspection and condition testing program did not find any items of immediate concern.

5.3.3.4.b. Station Service Transformer

The station service transformer is not conducive to being refurbished, and as such will be monitored for signs of fatigue. When the transformer is deemed to be close to failure, it will be replaced. FFPC expects to achieve a useful service life of 45 years.

5.3.3.4.c. Station DC System

The Station DC Systems require ongoing maintenance, as well as ongoing refurbishments in order for them to reach their maximum useful service life. FFPC performs annual battery cell testing to determine which cells no longer hold an acceptable charge and replaces them as required. This approach ensures that the system as a whole operates at acceptable performance levels. In the event of a premature charger failure, it is worth while repairing or replacing the charger and not necessarily replacing the battery banks.

5.3.3.4.d. Metal Clad Switchgear

FFPC's metal clad switch gear is inspected and condition tested on a three year rotation according to FFPC's maintenance inspection program. The switchgear is original to the station, and one lineup is actually older than the station as it was purchased slightly used. FFPC's strategy is to sustain the life of switchgear until the transformer station as a whole reaches the end of its useful service life. The switchgear is currently found to be in good health with respect to age, not requiring any significant sustainment investments at this time. As such, FFPC's inspection and condition testing program will be relied upon to drive future maintenance and sustainment activities.

5.3.3.4.e. Station Independent Breaker

Fort Frances MTS's station independent breaker has been identified as a major station component that is not expected to be sustainable until the station as a whole is planned to be decommissioned in 2034. The main reason for this is due to the fact that the unit was purchased used and as such was manufactured in 1947. The unit has surpassed its maximum useful life of 65 years and cannot be refurbished as parts have become obsolete. The most recent inspections and condition tests have found the unit to be in good working condition, with no immediate signs of failure. The purpose of the unit is

to protect the entire station from sustaining damage in the event of a fault. FFPC has therefore determined to closely monitor the health of the unit until its planned replacement in 2018.

5.3.3.4.f. Station Switches

The station switches are also original to the station, and as such are of early 1970's vintage. The life expectancy of these switches aligns with the life expectancy of other core station components, and as such, FFPC's strategy is to refurbish the switches as required until their anticipated decommissioning along with the station as a whole in 2034. The switches are expected to reach their maximum useful service life of 60 years. The most common refurbishment of these switches is insulator replacements. FFPC's 2013 annual inspection and condition testing did not identify any defects, and as such the switches are found to be in overall good health.

5.3.3.4.g. Electromechanical Relays and Digital & Numeric Relays

Electromechanical relays have been become obsolete with the availability of low cost microprocessor based digital relays. Modern day relays offer considerably more functionality and require less maintenance compared to older single function electromechanical relays. FFPC's strategy is therefore not to refurbish electromechanical relays but rather replace them with modern day technology in the event of failure.

5.3.3.4.h. Rigid Busbars

FFPC expects that the service life of the rigid busbars in the transformer station will easily outlast the useful service life of the station as a whole. FFPC is not aware of any practical sustainment activities for rigid busbars. The units are inspected according to FFPC's maintenance inspection program, and any necessary maintenance work, such as contact cleaning, is performed at the time of inspection.

5.3.3.4.i. Steel Structure

FFPC expects that the useful service life of the steel structure will outlast the useful service of the station as a whole. The steel structure generally does not require any maintenance or sustainment activities. Fort Frances also has not had issues with acidic rain causing excessive deterioration. The structure is inspected annually for defects but to date none have been identified. FFPC's strategy is to sustain the steel structure of Fort Frances MTS until the retirement of the station as a whole in 2034.

5.3.3.5 Underground Plant Lifecycle Optimization Policies and Practices

5.3.3.5.a. Primary TR XLPE Cables is Duct

FFPC's underground primary conductor is used to connect feeders to the transformer station, in newer subdivisions in place of overhead lines as well as to connect the distribution system to pad-mounted transformers. The age distribution of FFPC's underground cables is not evenly distributed and as such large portions of assets are approaching their end of service life during relatively narrow timeframes. It is not feasible or practical for FFPC to replace all cable runs as they reach their ideal end of their service life. As such, FFPC has staggered the planned cable replacements over a longer timeframe.

As underground cables cannot be inspected, FFPC plans on starting a cable condition testing program in 2015. The purpose of the program will be to determine the degree of cable jacket deterioration, from which replacement or sustainment activities will be identified and prioritized. FFPC plans on smoothing out the age profile of cable runs through the utilization of cable sustainment investments.

Approximately 6 km of critical underground cables are reaching the end of their service life over the 2014 to 2018 planning horizon. These cables essentially supply three feeders from the transformer station, and as such are crucial to the reliability of the distribution system, as approximately 50% of FFPC customers depend on them. FFPC has therefore placed the highest priority on addressing these cables. FFPC must also be mindful that cable replacements or rejuvenation cannot practically be performed during the winter months. It is worth noting that approximately 30% of all TR XLPE cables will reach the end of their service life between the period 2014 and 2018.

5.3.3.5.b. Secondary Cables Direct Buried

FFPC does not plan on rejuvenating secondary cables but rather to replace them according to FFPC's asset management plan. FFPC plans on replacing the cables using a "just in time" proactive approach, such that the replacements can be conducted under planned and coordinated circumstances as opposed to under emergency circumstances. Unplanned failures during the winter months require that temporary overhead services be installed, as well as that the underground service be replaced the following spring. Winter failures add considerable unnecessary expense and should be avoided.

5.3.3.5.c. Pad-Mounted Transformers

FFPC does not refurbish pad-mounted transformers and generally speaking, transformers require little maintenance. FFPC's asset management approach is to perform just-in-time replacements, such that replacements are conducted under planned and coordinated circumstances as opposed to under emergency repair circumstances. Factors that influence transformer replacements include their relative health index as determined by FFPC's asset management process, as well as, the impact of failure. The pad-mounted transformer population for single phase transformers is not evenly distributed, and as such FFPC faces somewhat of a "tidal wave" affect, beginning in 2015. This necessitates that FFPC ramp

up its replacement program, beginning with replacements that are found to have the lowest health and highest impact of failure. FFPC's asset management process is utilized to prioritize the order in which individual transformers require replacing.

FFPC is currently working on mapping out transformer to smart meter relationships such that transformer load profiles can be established. FFPC intends to use the loading data to refine Adjusted End-of-Life values, as there is a direct correlation between transformer loading and transformer longevity. The data will essentially give insight into how hard transformers are working and it will also allow for optimum transformer sizing as the units are replaced. It is also important to note that FFPC has experienced long manufacturing delays with transformers, as much as 42 weeks. This underscores the importance of proactively indentifying transformers that are close to failure such that suitable volumes of replacements can be sourced ahead of time. FFPC's fleet of spare transformers is currently not sized for increased transformer failure rates and as such it is important to proactively acquire transformers over the 2014 to 2018 planning period.

5.3.3.5.d. UG Foundations

Underground foundations generally do not require any maintenance and their refurbishment is not very practical. FFPC's strategy is to try to align two lifecycles of pad-mounted transformers for every one lifecycle of the underground foundation. As such, FFPC expects to replace underground foundations on an 80 year cycle. All of FFPC's underground foundations are relatively new, and as such FFPC does not foresee any underground foundations requiring replacement in the near future. The underground foundations are also inspected annually as part of FFPC's maintenance inspection program, and any identified deficiencies are addressed accordingly. In recent history, inspections have only identified one deficiency related to a transformer base tilting. The soil conditions were found to be unstable and the base has since been straightened.

5.3.3.5.e. Ducts

Ducts generally do not require any maintenance and their refurbishment is not practical. Given that ducts are buried, they are also not conducive to maintenance inspections. FFPC's strategy is to align one lifecycle of ducts with two lifecycles of cable replacements. As such, FFPC expects to replace ducts on an 80 year lifecycle. This will save unnecessary excavation, landscaping, labour and material costs.

5.3.3.5.f. Concrete Encased Ducts

Concrete encased ducts generally do not require any maintenance and their refurbishment is not practical. Given that concrete encased ducts are buried, they are also not conducive to maintenance inspections. FFPC's strategy is to align one lifecycle of concrete encased ducts with a minimum of two lifecycles of cable replacements. As such, FFPC expects to replace ducts on a minimum 80 year lifecycle. This will save unnecessary excavation, landscaping, labour and material costs.

5.3.3.5.g. Cable Chambers

Cable chambers require very little maintenance and their refurbishment is not practical. FFPC performs minor maintenance such as cleaning or exterior painting of the chambers. The chambers are also inspected annually as part of FFPC's underground plant inspections program. Inspections typically focus on ensuring no animal intrusions have occurred and that the cable terminations they house are in good condition.

5.4 Capital Expenditure Plan

FFPC has developed this DS Plan with a focus of delivering value for money and to achieve the four performance outcomes established in the OEB's renewed regulatory framework for electricity (Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance). The DS Plan was constructed using a data driven "bottom up" approach, utilizing FFPC's newly developed asset management and capital planning process. FFPC's GIS system has been an invaluable tool, enabling improved asset oversight, identifying individual assets that are approaching the end of their useful service life due to their high risk of failure.

The following investment drivers have had a material impact on the DS Plan for 2014 to 2018 planning period: Mandated Service Obligations; Asset Failure and Risk of Failure; Asset End-of-Life High Performance Risk; Customer Preference; Reliability Objectives; Safety Objectives; necessary Non-System Physical Plant; Business Operational Efficiency and Performance Improvements; and System Capital / Maintenance Support.

5.4.1 Summary

5.4.1.1 Capability to Connect New Load or Generation Customers

FFPC's distribution system currently does not extend to existing customers in three areas along the outskirts of the municipal boundaries that define FFPC's licensed electrical distribution service territory. The customers in these pockets are currently physically connected to and serviced by Hydro One Network's Inc.'s distribution network. FFPC plans to extend its feeders along these three locations, to eliminate Long Term Load Transfer arrangements with HONI. All six of FFPC's distribution feeders have considerable capacity for the addition of load, as well as generation. FFPC's over 50 kV transformer station which services FFPC's licensed service territory, also has considerable capacity for the addition of new customer load and renewable generation. As such, FFPC welcomes the opportunity for increased customer load, as well as renewable generation.

FFPC's distribution feeders are currently operating at 30% of their maximum capacity, relative to their ampacity limitations (conductor sizes). FFPC's transformer station "Fort Frances MTS", is currently operating up to approximately 72% of its capacity during peak demand periods, relative to power transformer sizing in redundant operating mode. For detailed utilization data refer to sections 5.3.2.2.e.ii "Overhead Distribution System Capacity & Utilization", 5.3.2.2.d.ii "Transformer Station Capacity & Utilization", and 5.3.2.2.f.ii "Underground Distribution System Capacity & Utilization".

FFPC is well positioned to accommodate customer growth, as well as renewable generation. The distribution system code requires all LTLT arrangements to be eliminated by June 30th, 2014, and as such FFPC has allocated $371,739 for distribution system expansions to eliminate the LTLT arrangements as per the requirements of the DSC. The nature of one of the three expansion locations will involve crossing a CN Railroad right-of-way, which will unlock electrical utility access to approximately 15.4% of

FFPC's licensed distribution service territory that is currently not developed. All three expansions combined will unlock access to approximately 25.4% FFPC's service territory that is currently not developed. All three expansions align well with future municipal expansion territories. As previously mentioned, the system expansions will also eliminate a long standing issue with the distribution of the 1905 Historic Power Credit to LTLT customers.

5.4.1.2 Total Annual Capital Expenditure Summary by Investment Category

The following table summarizes all of FFPC's planned capital expenditures over the 2014 to 2018 forecast period. The table is based on the example provided in the Chapter 5 filing Guide under section 5.4; however historic period is removed and investment category totals for the planning period have been added.

Investment Category	2014	2015	2016	2017	2018	2014 - 2018 Total
	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)	Planned Expenditures ($'000)
System Access	421.7	40.0	20.0	45.0	12.0	538.7
System Renewal	253.6	418.9	504.3	531.0	360.7	2068.5
System Service	48.5	142.0	60.0	58.0	15.0	323.5
General Plant	96.5	75.5	76.0	33.0	310.5	591.5
Total	820.3	676.4	660.3	667.0	698.2	3522.2
System O&M	24.3	13.0	7.1	7.8	2.5	54.7

As per the Section 5.4.4 filing requirements, the following summary table in accordance to "Table 2-Capital Expenditure Summary", and summarizes FFPC's capital expenditures by investment category for the period 2006 through 2018. The original table can be found under the "Exhibit 2 Appendices" worksheet, under Tab "App.2-AB_Capital_Expenditures". "Explanatory notes on variances are not provided as this is FFPC's first DS Plan under the new filing requirements, and as such "Planned to Actual" balances are not yet available.

CATEGORY	Historical Period (previous plan[1] & actual)															
	2006			2007			2008			2009			2010			
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	
System Access		-	--		-	--		-	--		-	--		-	--	
System Renewal		191	--		130	--		154	--		153	--		166	--	
System Service		43	--		43	--		16	--		6	--		80	--	
General Plant		100	--		21	--		17	--		118	--		277	--	
TOTAL EXPENDITURE	-	335	--	-	194	--	-	187	--	-	278	--	-	523	--	
System O&M		$ 248	--		$ 281	--		$ 305	--		$ 325	--		$ 376	--	

CATEGORY	Historical Period (previous plan[1] & actual)									Forecast Period (planned)				
	2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		3	--		41	--		37	--	422	40	20	45	12
System Renewal		133	--		165	--		150	--	254	419	504	531	361
System Service		1	--		-	--		55	--	49	142	60	58	15
General Plant		9	--		16	--		157	--	97	76	76	33	311
TOTAL EXPENDITURE	-	145	--	-	222	--	-	399	--	820	676	660	667	698
System O&M		$ 365	--		$ 591	--		$ 423	--	$ 675	$ 722	$ 777	$ 839	$ 894

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

5.4.1.3 Linking Investment Categories to Planning Process Outcomes

Planned System Access investments are dedicated towards the elimination of LTLT arrangements, as well as towards the upgrade of 1970's instrumentation and controls at the over 50 kV transformer station. The transformer station upgrades will enable the connection of renewable generation, as well as they accomplish several smart grid directive objectives. FFPC has committed $371,739 in 2014 to eliminate all LTLT arrangements as per the requirements of the DSC, as well as a total of $167,000 between 2014 and 2018 to upgrade transformer station protection and controls. The upgrades will also enable FFPC to monitor the performance and health of core station components, as well as of individual feeders. FFPC's local economy is in a state of recession due to the local pulp and paper mill laying of the majority of its work force over the last several years. The future prospect of the plant is unknown at this time. As a result of this, FFPC does not foresee any material customer growth over the forecast period and as such, has not allocated any capital expenditures towards customer driven load expansions. A total of $538,739 has been allocated towards System Access expenditures, representing 15.3% of the total planned capital expenditures over the forecast period.

System Renewal is by far the most dominant investment category demanding capital reinvestment. Due to FFPC's entire distribution system being rebuilt during a narrow window from the mid 1970s to mid 1980s, FFPC has historically operated in a "Maintenance Mode". As such, FFPC required relatively low levels of capital reinvestments as most distribution assets were relatively new. A disproportionately high portion of FFPC's asset base is approaching the end of its useful service life over the planning period, posing a high risk of failure. The outcomes of the asset management process have resulted in FFPC shifting from its current maintenance mode to a capital reinvestment mode going forward. The overall level of investment towards System Renewal had been increased according to FFPC's asset management process, in preparation for the large volume of assets predicted to fail in the near future. The overall average useful remaining life of FFPC's entire asset base is approximately 41.5%, as dictated by FFPC's asset management process (based on FFPC's Adjusted End-of-Life (AEOL) projection methodology that has been applied to individual assets). Based on the TUL values established in the "Kinectrics Report", the overall average useful remaining life of FFPC's asset base would be reduced to approximately 33.4%. FFPC's asset management and capital planning processes have resulted in planned system renewal investments of $2,068,466 over the 2014 to 2018 planning horizon. The Poles, Towers & Fixtures and Line Transformers categories reinvestments combined, account for 80% of all planned System Renewal expenditures. FFPC has committed $649,638 for Poles Tower & Fixtures and

$1,007,541 towards line transformers (overhead and underground combined). Approximately 58.7% of all planned capital expenditures over the forecast period are towards System Renewal.

System Service expenditures are largely driven by FFPC's desire to achieve operational objectives including; customer preference; maintaining/improving service reliability; and the elimination of potential safety hazards. Over the forecast period FFPC has committed a total of $323,500 towards the System Service category, which represents approximately 9.2% of total planned capital expenditures. Significant planned activities under this category include the installation of a $62k fire barrier in 2015, a $43k Outage Management System in 2017, a $60k Financial Information System ($40k 2015, $20k 2016), a total of $100k towards operational reliability improvements, and $28k towards eliminating safety hazards. The fire barrier will be constructed between the two transformer station power transformers as they are in close proximity to one another. The barrier will mitigate the risk of a critical failure of one power transformer causing damage to the other. The Outage Management System (OMS) will enable FFPC to respond to outages proactively, assist in pin-pointing equipment failures, offer improved oversight of the performance of FFPC's distribution system, as well as improve customer communication regarding outages. FFPC's current financial information system is very antiquated and lacks effective reporting, data export capability, and the ability to perform data analyses. FFPC is planning to purchase and transition to a more suitable tool such as Microsoft Great Plains. The elimination of identified Safety hazards as well as strategic reliability improvements projects are also included in this category.

General Plant investments are necessary in order for FFPC to support and improve the efficiency of day to day business and operational activities. Over the forecast period, FFPC has committed $592k towards General Plant, which represents approximately 16.8% of the total planned capital expenditures. FFPC is planning to invest $403k into its rolling stock, due to three service vehicles (a Double Bucket truck and two Pickup Trucks), as well as two trailers (chipper and wire stringing/tensioning trailer), reaching or surpassing their maximum useful service life. FFPC also has various smaller initiatives planned, such as business efficiency improvement initiatives, computer replacements and software updates.

5.4.1.4 Summary of Annual Capital Expenditures by Category

The following tables summarize FFPC's planned annual capital expenditures activities by Budget Year, Investment Category, Parent Project ID, Project Activity Name, Cost, USoA Account, Primary Investment Driver and Kinectrics Report Asset Group:

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	General Plant	14-14-007	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		14-14-007	Building Heater Replacements	$3,000	Transformer Station heater replacements	1808	Non-System Physical Plant	G5 - Station Buildings
		14-14-007	Cable Reel Stands	$2,000	Install cable reel stands at Operations Centre	1908	System Cap / Maint Support	G3 - Administrative Buildings
		14-14-007	Replace Shelving	$2,000	Upgrade stores area shelving at Operations Centre	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Meter Room Flooring	$2,500	Misc. meter room improvements - replace flooring and fixtures	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Office A/C	$1,000	Install air conditioning in lunch room	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Admin Area Renovation	$3,500	Misc. Main Office renovations - Reception area	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		14-14-007	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		14-14-007	Operations Centre Copier	$4,000	Replace Operations Centre end-of-life multimedia centre	1920	Non-System Physical Plant	G1 - Office Equipment
		14-14-007	Computer Hardware	$5,000	Director laptop computers to support real-time communication and paperless information distribution.	1920	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	AMI MAS Server Replacement	$4,000	Replace end-of-life AMI system Master Application Server.	1920	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	AutoCad License	$2,000	Upgrade AutoCad drafting software for technical blue print management	1611	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	MS Office Productivity Package	$2,000	Director MS office productivity package to support real-time communication and paperless information distribution.	1611	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
		14-14-007	Label Printer - Asset Labeling	$2,500	Asset labeler for asset identification initiative (GIS).	1940	Business Operation Eff	G7 - Equipment
		14-14-007	Transformer Safe Transport Kit	$3,000	Transformer safe transport kit to mitigate risk of environmental spill from handling increased volume of failing transformers.	1940	Obj - Safety	G7 - Equipment
		14-18-005	Replace 1978 Fort Garry Industries Cable Reel Trailer	$50,000	Replace end-of-life cable stringing and tensioning trailer.	1930	Non-System Physical Plant	G2 - Vehicles
Total				$96,500				
2014	System Access	14-14-006	LTLT Elimination Pole Lines (88 Pri Spans)	$294,681	Overhead distribution feeder pole line expansions to connect to LTLT customers	1830	Mandated Service Obligations	1 - Fully Dressed Wood Poles
		14-14-006	LTLT Elimination Conductor	$9,180	Primary conductor for LTLT pole line extensions	1835	Mandated Service Obligations	8 - OH Conductors
		14-14-006	LTLT Elimination Directional Bore & Conduit	$27,000	Directional bore underneath CNR right-of-way and install conduit for feeder expansion to connect to LTLT customer.	1840	Mandated Service Obligations	40 - Ducts
		14-14-006	LTLT Elimination Pri UG Conductor	$2,298	Install UG primary conductor in duct (across CNR right-of-way), to extend feeder to connect to LTLT customer.	1845	Mandated Service Obligations	29 - Primary TR XLPE Cables in Duct
		14-14-006	LTLT Elimination Transformers	$38,580	Install new transformer to supply LTLT customers from expanded feeders	1850	Mandated Service Obligations	9 - OH Transformers
		14-18-004	Transformer T1 Protection	$25,000	REG Investment - Transformer Station power transformer T1 control and relaying upgrade.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays

		14-18-004	Transformer T2 Protection	$25,000	REG Investment - Transformer Station power transformer T2 control and relaying upgrade.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
Total				$421,739				
2014	System Renewal	14-14-007	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		14-14-007	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		14-14-007	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		14-14-007	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life CT & PT metering settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		14-14-007	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
		14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$11,036	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	3 Phase Pad Mounted Tx	$25,106	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$47,546	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$11,960	Replace end-of-life critical spare transformers	1850	EOL - Failure	9 - OH Transformers
		14-18-003	Non-Profit Housing - 400 Blk Sixth St W - S118A To AT15	$4,642	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Sixth St Non-Profit Housing	$1,598	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Rainy Crest	$10,010	Replace end-of-life primary underground cables to nursing home.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
Total				$253,576				
2014	System Service	14-14-007	Primary Insulator Replacements	$10,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		14-14-007	Air Break Switches Insulator Replacements	$4,500	Air break switch primary insulator replacements as per inspection findings	1835	Obj - Reliability	4 - OH Line Switch
		14-14-007	Robert Moore Air Break Switch Relocation	$28,000	Remove, replace and relocate air break switch from School Yard	1835	Obj - Safety	4 - OH Line Switch
		14-14-007	Mobile Work Tablets	$2,500	Purchase mobile work tablets for transition to electronic inspection forms and for line crew on-site access to technical documentation.	1920	Other Performance/Functionality	G6 - Computer Equipment
		14-14-007	Elster Tx Primary Data Logger and Meter	$3,500	Primary meter for transformer setting, to support identification of theft of power and transformer loading profile development.	1945	Obj - Safety	G7 - Equipment

Total				$48,500				
2014 Total Capital Budget				**$820,316**				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2015	General Plant	14-18-005	Replace 1999 Ford Pickup	$38,000	Replace end-of-life crew service/support vehicle.	1930	Non-System Physical Plant	G2 - Vehicles
		15-15-009	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		15-15-009	Build Outdoor Transformer Shelter	$6,000	Install weather shelter for transformer yard storage area.	1908	System Cap / Maint Support	G3 - Administrative Buildings
		15-15-009	Replace Shop Rollup Door	$12,000	Replace operations centre rollup garage door.	1908	System Cap / Maint Support	G3 - Administrative Buildings
		15-15-009	Reg & Finance Area Renovations	$3,500	Misc. Main Office renovations - Finance Area	1908	Non-System Physical Plant	G3 - Administrative Buildings
		15-15-009	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		15-15-009	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		15-15-009	PC Replacement	$5,000	Replace end-of-life computers at the Main Office.	1920	Non-System Physical Plant	G6 - Computer Equipment
		15-15-009	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		15-15-009	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
Total				$75,500				
2015	System Access	14-18-004	Station Data Acquisition System	$20,000	REG Investment - install data acquisition system to connect to station IED's (intelligent electronic devices).	1531	Mandated Service Obligations	43 - Remote SCADA
		14-18-004	Station Communication Network Installation	$20,000	REG Investment - Install local area network at TS to enable connection of IED's and access to operating data.	1531	Mandated Service Obligations	G8 - Communication
Total				$40,000				
2015	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$135,682	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$72,234	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$32,660	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	1557 Colonization Rd W U/G	$8,609	Replace end-of-life primary underground cable servicing residential area	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

		14-18-003	UG Feeder Cable Condition Testing & Rejuvenation Pilot	$28,000	Rejuvenate end-of-life primary underground feeder cables - pilot silicone injection technology project.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		15-15-009	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		15-15-009	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		15-15-009	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		15-15-009	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		15-15-009	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$418,863				
2015	System Service	15-15-008	Transformer Fire Barrier	$62,000	Install fire and blast barrier between power transformer T1 and T2.	1808	Obj - Reliability	G5 - Station Buildings
		15-15-009	Backup Generator Switch / Install	$4,500	Install transfer switch and panel for connection of emergency backup generation to supply station lighting and DC battery bank chargers.	1808	Obj - Reliability	G5 - Station Buildings
		15-15-009	Generator	$5,500	Transformer Station backup generator for emergency lighting and DC system charging.	1808	Obj - Reliability	G5 - Station Buildings
		15-15-009	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		15-15-009	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		15-15-009	Mass Customer Contact System	$15,000	Install and commission mass customer contact system to enable contacting customers regarding important event such as power interruptions.	1955	Customer Preference	G8 - Communication
		15-16-010	Financial Information System Phase 1	$40,000	Purchase and commission Financial Information System to enable data exports, enhanced reporting and data analysis for planning activities.	1611	Business Operation Eff	G6 - Computer Equipment
Total				$142,000				
2015 Total Capital Budget				**$676,363**				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2016	General Plant	14-18-005	Replace 2003 Ford 4x4 Half Ton	$40,000	Replace end-of-life crew service/support vehicle.	1930	Non-System Physical Plant	G2 - Vehicles
		16-16-012	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		16-16-012	Interior Lighting Retrofit	$3,000	Transformer Station T12 lighting replacements	1808	Business Operation Eff	G5 - Station Buildings
		16-16-012	Yard Landscaping	$3,000	Landscape yard at Operations Centre - Install flower beds and general yard improvements	1908	System Cap / Maint Support	G3 - Administrative Buildings
		16-16-012	Cable Reel Shelter	$6,000	Install shelter over outdoor cable reel storage area	1908	System Cap / Maint Support	G3 - Administrative Buildings
		16-16-012	Office Carpeting	$2,500	Replace Main Office carpets.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		16-16-012	Executive Area Renovations	$3,500	Misc. Main Office renovations - Board Room	1908	Non-System Physical Plant	G3 - Administrative Buildings
		16-16-012	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		16-16-012	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		16-16-012	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		16-16-012	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
		16-16-012	Main Office Telephone Data Logger	$7,000	Purchase and commission Main Office telephone system data logger, to support telephone accessibility related RRR reporting.	1955	Business Operation Eff	G8 - Communication
Total				$76,000				
2016	System Access	14-18-004	Station OCB Protection	$20,000	REG Investment - Upgrade station independent breaker controls and protection.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
Total				$20,000				
2016	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$49,680	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	3 Phase Pad Mounted Tx	$66,319	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$37,031	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$31,050	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	Westfort Apartments	$2,457	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

		14-18-003	Green Manor Apartments	$2,542	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Rose Manor Apartments	$1,574	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		16-16-011	1947 OCB Replacements	$150,000	Replace end-of-life station independent breaker at Transformer Station.	1815	EOL - Failure Risk	17 - Station Independent Breakers
		16-16-012	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		16-16-012	T1 Battery Charger	$22,000	Replace end-of-life battery charger for Transformer Station T1 DC system.	1825	EOL - High Performance Risk	15 - Station DC System
		16-16-012	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		16-16-012	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		16-16-012	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		16-16-012	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$504,331				
2016	System Service	15-16-010	Financial Information System Phase 2	$20,000	Integrate payroll and purchasing into FIS system.	1611	Business Operation Eff	G6 - Computer Equipment
		16-16-012	115 kV Sky Structure Insulator Replacements	$25,000	Replace Transformer Station primary insulators on sky structure.	1815	Obj - Reliability	23 - Steel Structure
		16-16-012	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		16-16-012	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
Total				$60,000				
2016 Total Capital Budget				$660,331				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2017	General Plant	17-17-013	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		17-17-013	Technical Station Renovations	$3,000	Transformer Station technical station renovations	1808	System Cap / Maint Support	G5 - Station Buildings
		17-17-013	Training Room Carpeting	$2,500	Replace carpeting in the training room located at the Operation Centre.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		17-17-013	Door Replacements	$2,000	Operations Centre door replacements.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		17-17-013	Technical Workstation Replacement	$3,500	Misc. Main Office renovations - Technical Office	1908	Non-System Physical Plant	G3 - Administrative Buildings
		17-17-013	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		17-17-013	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		17-17-013	Media Centre (Photo Copier)	$11,000	Replace the Main Office end-of-life media centre.	1920	Non-System Physical Plant	G1 - Office Equipment
		17-17-013	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		17-17-013	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
Total				$33,000				
2017	System Access	14-18-004	Station Supervisory Control	$45,000	REG Investment - Install station controller and commission station supervisory control (monitor operating conditions and perform appropriate control actions currently performed manually).	1531	Mandated Service Obligations	43 - Remote SCADA
Total				$45,000				
2017	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$123,932	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	3 Phase Pad Mounted Tx	$40,213	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$118,209	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pad Mounted Tx Spares	$15,525	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx Spares	$11,500	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	Rainbow Motel	$917	Replace end-of-life primary underground cables to multi-residential business complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Armstrong Apartments	$659	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

		14-18-003	Shevlin Towers West	$1,667	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Shevlin Towers East	$1,672	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Feeder UG Cable Refurbishment Phase 1	$75,000	Rejuvenate end-of-life primary underground feeder cables. Attempt to sustain cables until Transformer Station as whole is at its end-of-life in 2034, at which time cables become obsolete.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		17-17-013	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		17-17-013	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		17-17-013	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		17-17-013	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		17-17-013	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$530,971				
2017	System Service	17-17-013	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		17-17-013	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		17-17-013	Elster "Access Detect" (OMS)	$43,000	Purchase and commission Outage Management System, to enable proactive outage alerts and localized customer interaction.	1611	Customer Preference	G6 - Computer Equipment
Total				$58,000				
2017 Total Capital Budget				**$666,971**				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2018	General Plant	14-18-005	Replace Chipper Trailer	$25,000	Replace end-of-life chipper trailer to support vegetation management maintenance program.	1930	Non-System Physical Plant	G2 - Vehicles
		14-18-005	Replace 2004 Altec Double Bucket Truck	$250,000	Replace end-of-life double bucket truck, to support maintenance, capital and operational activities.	1930	System Cap / Maint Support	G2 - Vehicles
		18-18-014	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		18-18-014	Bathroom Renovation	$2,000	Transformer Station bathroom renovations	1808	System Cap / Maint Support	G5 - Station Buildings
		18-18-014	Window Replacements	$6,000	Replace Operations Centre windows.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		18-18-014	Main Office Bathroom Renovations	$3,500	Misc. Main Office renovations - Bathroom	1908	Non-System Physical Plant	G3 - Administrative Buildings
		18-18-014	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		18-18-014	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		18-18-014	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		18-18-014	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
		18-18-014	Phone System Upgrade	$13,000	Replace end-of-life Meridian phone system at the Main Office.	1955	Non-System Physical Plant	G8 - Communication
Total				$310,500				
2018	System Access	14-18-004	Station DC System Monitoring & Remote Annunciation	$12,000	REG Investment - Install supervisory control over auxiliary station components including DC systems.	1531	Mandated Service Obligations	43 - Remote SCADA
Total				$12,000				
2018	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$48,430	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$115,053	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$14,375	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	Strachan pl. switch S22-B	$9,874	Replace end-of-life primary underground cables in multi-residential area.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Riverview Cemetery	$5,741	Replace end-of-life primary underground cables to public municipal building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	CIBC	$575	Replace end-of-life primary underground cables to priority business customer.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

		14-18-003	Feeder UG Cable Refurbishment Phase 2	$25,000	Rejuvenate end-of-life primary underground feeder cables. Attempt to sustain cables until Transformer Station as whole is at its end-of-life in 2034, at which time cables become obsolete.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		18-18-014	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		18-18-014	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		18-18-014	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		18-18-014	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		18-18-014	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$360,724				
2018	System Service	18-18-014	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		18-18-014	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
Total				$15,000				
2018 Total Capital Budget				**$698,224**				

5.4.1.5 Impact of Regional Planning Process on DS Plan

No formal Regional Planning Process meetings have occurred and as such FFPC is not aware of any corresponding deliverables that may impact this DS Plan. As per the Process Planning Working Group's June 7, 2013 presentation to distributors, it is expected to take up to four (4) years to complete the first planning cycle. As such, FFPC has not allocated any capital expenditures towards Regional Planning deliverables over the forecast period.

5.4.1.6 Customer Engagement Activities

FFPC engaged its customers through means of a customer satisfaction survey which was conducted during July and August of 2013. For detailed information regarding the engagement activity refer to Section 5.2.2.4, 5.2.3.5, 5.4.1.8.a as well as Appendix 3 for the complete survey results. The survey was very well received and considerable feedback was obtained. This allowed FFPC to gain valuable insight into customer needs, values, preferences and expectations. Customers overwhelmingly expressed a high level of satisfaction with FFPC in general, with the reliability of their electricity supply, as well as with current service offerings.

5.4.1.7 Distribution System Development over Forecast Period

Based on the current state of the local economy, ongoing conservation and demand management efforts, as well as current renewable generation uptake levels, FFPC anticipates that its overall volume of electricity as delivered to its single supply point will decrease slightly over the forecast period. FFPC's local economy is in a state of recession due to its largest employer curtailing its operation, thereby reducing its workforce to approximately 20%. As such, FFPC is forecasting decreased customer counts over the planning horizon, resulting in downward pressure on consumption demands.

Conservation and demand management efforts have gained considerable traction. FFPC anticipates being able to achieve its 2011 to 2014 Conservation Targets, which would represent a cumulative volumetric reduction of 3.64 GWh, as well as a 0.61 MW reduction in annual peak demand.

FFPC anticipates connecting approximately 62.5 kW of renewable generation year-over-year, based on FFPC's average project uptake between the years 2011 and 2013. It is also worth noting that FFPC has been approached by several microFIT and FIT applicants wishing to relocate their projects to FFPC's service territory. The combined relocation projects represent 360 kW of generation capacity, of which 20 kW have are approaching project completion. The applicants had their original projects approved outside of FFPC's service territory; however, they could not be connected due to capacity constraints and as such were subject the OPA's relocation program offering. It is important to note that given the continued high level of interest in renewable generation, FFPC is planning to upgrade the controls and protection at its over 50 kV transformer station to increase connection capacity. The planned upgrades will also enable feeder monitoring from which less restrictive constraints can be established, as well as they will accommodate reverse power flow. Refer to section 5.4.3 for detailed system constraints, as well as the planned renewable enabling investments that will alleviate them.

5.4.1.8 Special Capital Projects

5.4.1.8.a. Customer Preference

Based on the feedback received from the 2013 customer engagement (surveys), FFPC has included the following projects in response to customer preference:

- FFPC will deploy a mass customer contact system in 2015 that will enable FFPC to alert customers by telephone or email of important events such as planned power outages. This rollout is expected to require a capital investment of $15k. FFPC is planning to further enhance its communication and outage response capabilities though the deployment of an Outage Management System (OMS) in 2017. The OMS utilizes the existing AMI system deployed, and is expected to require a capital investment of $43k in 2017.
- Many customers felt that being billed on true calendar month consumption would serve them better. As such, FFPC is planning to transition its billing process such that all customers are billed on the consumption used between the first day and the end of the last day of every calendar month. This project will not require a capital investment; however, it will require considerable staff time to implement the transition.
- A significant portion of customers would like to receive electronic bills via email. In response to this request, as well as in support of the smart grid deployment objectives, FFPC is planning to deploy e-billing in early 2014. The expected capital rollout costs are $7k
- A portion of customers also expressed an interest in being able to access their consumption data and billing data online. FFPC is planning on offering customer access to this data in parallel to the e-billing rollout, and as such the service will be offered in early 2014. FFPC has allocated $5K towards capital expenditures.
- It is important to note that Fort Frances has a large elderly population who prefer traditional business communication methods, as most are not computer literate and as such do not utilize the internet or emails. FFPC's business strategy is to offer its consumers a choice of paper bills versus electronic bills, as well as preferred means of communication. This message was very clear as per the customer feedback received from the 2013 survey.
- Customers are also very interested in learning more about the electricity industry in general and about specific topics such as Conservation and Demand Management, Renewable Generation and Smart Grid. FFPC is planning on adding a Technical Customer Service Representative to its staff in 2014, who will be actively involved with all consumer engagement activities, such as conducting surveys and delivering consumer education campaigns. Other core job responsibilities include supporting the annual administration of FFPC's asset management process and assistance in all planning activities.

5.4.1.8.b. Technology Based Opportunities & Innovation

In 2005 FFPC invested in a Geographical Information System (GIS) which has evolved into a powerful core business system. The system is the heart of FFPC's current asset management process as well as day to day work planning. Since the original deployment, FFPC dedicated tremendous resources towards quantifying FFPC's asset base, as well as linking it to all practical available data sources such as inspection results, condition testing results, asset attributes (size, location, serial number, replacement cost etc.), and property information (ownership, easements, mailing address etc.). In 2011, FFPC was able to showcase its GIS system by qualifying to participate in the Scientific Research and Educational Development (SR&ED) Tax incentive program. FFPC does not require material capital expenditures towards its GIS system over the forecast period; however, significant staff time will be required to further enhance functionality.

In 2013 FFPC invested in a Work Planning module that is built on the foundation of its GIS system. The tool will allow FFPC to link work orders (capital and maintenance histories) to assets, track asset changes through the work order process (i.e. transformer moving from inventory to field) and to help optimize future investments by allowing costing analyses to performed with ease. FFPC is currently working on integrating the tool and as such will be devoting significant resources over the forecast period to fully commission it. FFPC does not require material capital expenditures towards this tool but rather staff time.

In 2017, FFPC plans to build on the foundation of its AMI system by investing $43k of capital expenditures on purchasing and integrating an Outage Management System (OMS). The OMS essentially utilizes smart meters and the smart meter network installed, to alert FFPC of system events. Typical system events include a metering losing power, implying a particular customer address losing power, which will prompt appropriate corrective action. A series of meters losing power can be used to infer that a transformer failed, which would again prompt FFPC to take appropriate action. The OMS will enable FFPC to respond to outages proactively, assist in pin-pointing equipment failures, as well as offer improved oversight of the performance of FFPC's distribution system as a whole.

5.4.1.8.c. Study/Innovation Projects

Over the forecast period FFPC will be focusing on further developing the functionality of its core business systems, to unlock their potential functionality. This will maximize FFPC's existing investment into its toolkit. FFPC does not have any capital investments earmarked specifically for "study" or "demonstrative" purposes; however, FFPC will be dedicating considerable resources towards further integrating technology into its business as discussed throughout this DS Plan. FFPC will specifically be focusing on further enhancing its asset management process, through developing asset specific health indexes, as well as adding a layer of "labour hours" required to replace individual assets to improve on resource planning and cost projections. Another focus area will be to continue to gather asset information such as mapping of customer to transformer relationships and mapping of direct buried secondary cable runs.

FFPC will also be adding a new financial information system to its toolkit and will be commissioning its GIS based work order system that was purchased in the fall of 2013. The additional tools will enable FFPC to link cost components (labour, fleet vehicle and material) directly to individual assets, provide an automated work order system, enable depreciation of assets to be tracked at the individual asset level, enable financial modeling, improve financial reporting and graphical representation of financial information, enable electronic data exports and imports, as well as provide a calculation engine (for automated generation of asset health indexes etc.).

5.2.1.1.a. Renewable Enabling Improvements

There has been significant interest and uptake within FFPC's service territory regarding the installation of renewable generation under the microFIT and FIT programs. FFPC's distribution network is well suited for hosting renewable generation. FFPC's most notable limitations regarding accommodating renewable generation are the lack of insight into individual feeder loading profiles, which have resulted in the establishment of conservative feeder constraints that error on the side of safety, as well as FFPC's transformer station is currently unable to accommodate reverse power flows at any level. FFPC is planning to alleviate these constraints by investing $167k over the forecast period, in protection and control upgrades at its greater than 50 kV transformer station "Fort Frances MTS". As the Northwest Region is no longer considered "Transmission Capacity Constrained", FFPC expects an additional 312 kW of renewable generation capacity to come on line between 2014 and 2018. For details regarding specific limitations and detailed renewable enabling improvements refer to section 5.4.3 "FFPC System Capability Assessment for Renewable Energy Generation".

5.4.2 Capital Expenditure Planning Process Overview

Step 5 of FFPC's Asset Management Process illustrates FFPC's capital expenditure planning process. FFPC evaluates and prioritizes all potential investment items based on the relevance and importance of the investment drivers, and how prospective investments align with satisfying capital planning objectives.

5.4.2.1 Origin of Capital Planning Objectives

FFPC's capital planning objectives are derived from its Corporate Vision, Mission and Values.

5.4.2.1.a. FFPC's Vision:

The Fort Frances Power Corporation strives to be a model distributor of electricity and supplier of supporting energy services, with excellence in customer focus, operational efficiency and community partnership.

5.4.2.1.b. FFPC's Mission:

To deliver electricity and provide supporting energy services safely, reliably and cost-effectively, in support of the well being of our community, for whom we exist.

5.4.2.1.c. FFPC's Values:

We Value Safety:

We believe that all work related injuries can be prevented, and we are committed to the safety of our employees and the general public. We are committed to providing our employees with all of the proper resources that allow them to work safely, as well as to ensure that public safety is maintained.

We Value Our Community and the 1905 Historic Power Agreement:

We believe that the well being of the 1905 Historic Power Agreement, held between the owner of the local generating station assets and the residents and small businesses of the Town of Fort Frances, is vital to the future success of our community. We are committed on behalf of the residents and small businesses of the Town of Fort Frances, to administer the agreement and to ensure that the rights and obligations of the agreement are upheld, thereby ensuring its longevity. We also believe we are stewards of our environment and, as such, we will conduct our business in an environmentally responsible manner. We believe that our success hinges largely on the success of our community.

We Value Our Employees:

We believe that our employees are the cornerstone of our organization. We are committed to providing a safe, healthy and fulfilling work environment for our employees, with fair remuneration, sound management and opportunities for learning and professional development.

We Value Customer Focus:

We are committed to offering superior customer services in a manner that responds to customer preferences and needs. We are committed to providing our customers with a safe and reliable supply of electricity at the lowest rates possible that do not undermine our viability.

We Value Operational Efficiency:

We believe in the philosophy of Continuous Improvement, and we will strive to continuously improve the efficiency of our operation and processes. We will continually improve by harvesting the innovation of our employees and by integrating technology into our business.

5.4.2.2 Strategic Capital Planning Objectives:

FFPC's capital planning objectives are to:

- Support FFPC in delivering electricity and providing supporting energy services safely, reliably, and cost-effectively.

Safety:

- To maintain the safety of the distribution system so that it does not present any undue hazards to personnel or to the general public.
- To meet or exceed all regulatory requirements with respect to electrical distribution system safety.

Reliability:

- To maintain the distribution system service reliability at a level that meets or exceeds the expectations of consumers and the community.
- To maintain the distribution system service reliability at a level that meets or exceeds regulatory requirements.

Cost Effectiveness:

- To support the outcomes of our asset management process balancing cost, reliability and risk.
- To support necessary reinvestments into our asset base to keep pace with asset deterioration.

Operational Efficiency:

- That investment decisions are based on the results of rigorous data driven processes.
- That our processes continually improve through the deployment of innovation and technology.

Customer & Community Focus:

- That our investment plans and service offering are aligned with needs and demands of our customers and community.
- That our investment decisions and service offerings support the well being of our customers and community, for whom we exist.

Meeting Obligations:

- That we remain compliant with all applicable governing agencies, laws and regulatory statutes
- That we support the deployment and implementation of all mandated service obligations

5.4.2.3 Ranking of Capital Investment Priorities:

FFPC selects and prioritizes its capital investments projects based on the degree to which they achieve the following objectives:

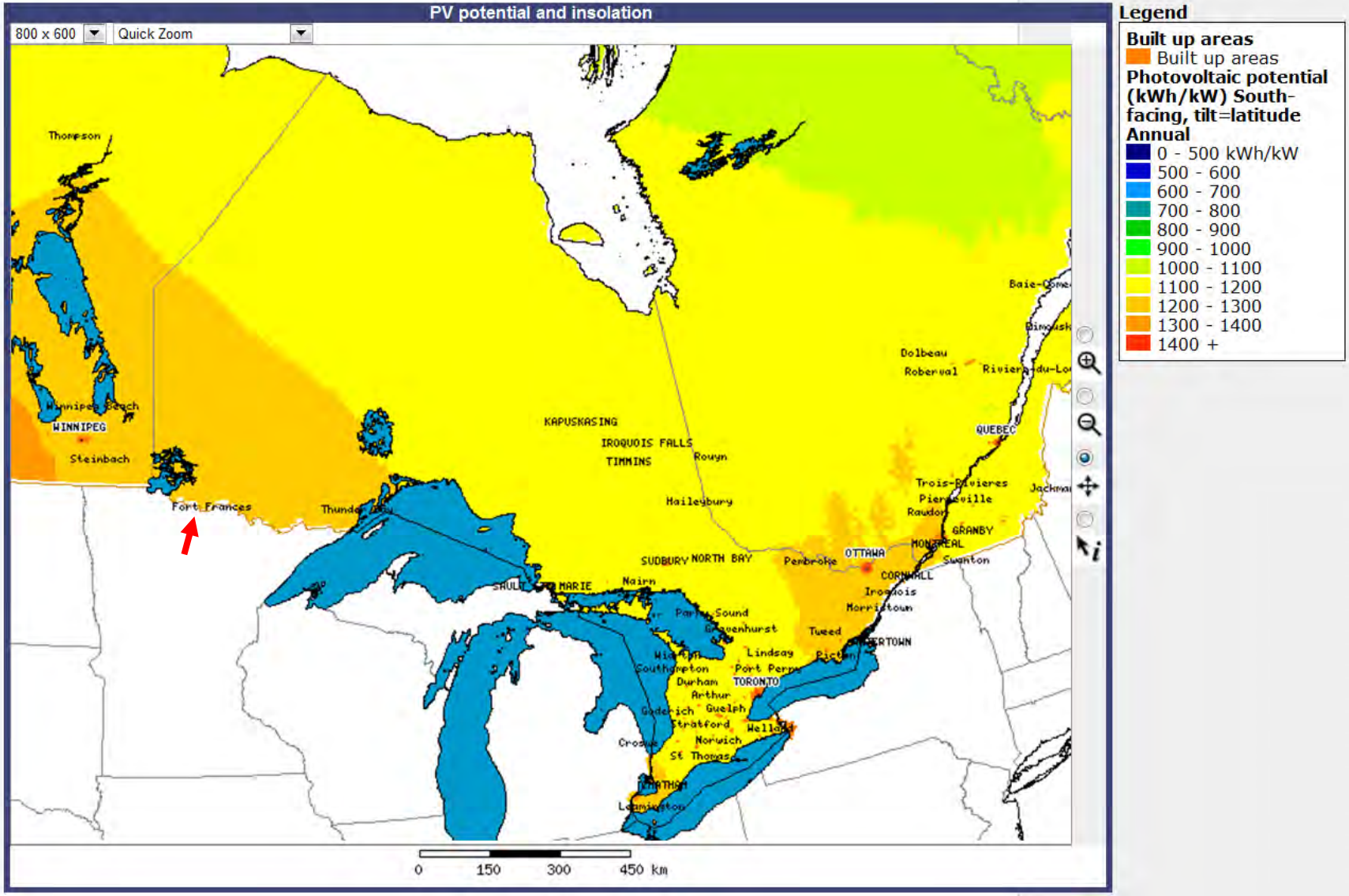
1. Ensuring that the health and safety of employees and the public is maintained
2. Eliminate or mitigate threats to the environment
3. Ensuring compliance to regulatory and legal obligations
4. Meeting the needs and preference of customers
5. Replacing, Sustaining or retiring assets that are at the end of their useful service life
6. Improving operational efficiency and effectiveness

5.4.2.4 Outlook for Accommodating Connection of Renewable Generation

FFPC's distribution system and service territory are well suited for the deployment of renewable generation, specifically for hydroelectric and photovoltaic. Solar radiation levels provided by Ministry of Agriculture and Food specify that Fort Frances is situated in the second highest photovoltaic potential zone (second highest sun radiation intensity). Furthermore, customer density is sufficient such that electricity generated will be consumed in close proximity, whereas outlying rural areas lack customer density (to consume the generation produced so that it does not have to be transported) resulting in many projects being rejected due to capacity limitations.

As FFPC owns and operates a distribution system, as well as a greater than 50 kV transformer station in close proximity of its customer base, it offers the flexibility of connecting smaller scale projects to its distribution system and larger scale projects directly to its transformer station. As previously mentioned, FFPC is planning on investing towards renewable enabling improvements at its greater than 50 kV transformer station. The station's current vintage of controls do not offer insight into feeder loading, as well as cannot accommodate reverse power flow at any level. Based on the current renewable generation interest level and on the October announcement that an additional 10 MW of capacity has been allocated to the Northwest region by the OPA, FFPC anticipates receiving increased volumes of generation connection requests. As such, FFPC also anticipates encountering connection

constraints in the near future, if it was not to proceed with the planned renewable enabling improvements. For detailed information regarding system limitations to accommodating renewable generation, as well as corresponding planned investments, refer to section 5.4.3. The following map illustrates the generation potential for PV systems in Ontario:


PV potential and insolation
800 x 600
Quick Zoom
Legend
Built up areas
Built up areas
Photovoltaic potential (kWh/kW) South-facing, tilt=latitude
Annual
0 - 500 kWh/kW
500 - 600
600 - 700
700 - 800
800 - 900
900 - 1000
1000 - 1100
1100 - 1200
1200 - 1300
1300 - 1400
1400 +
Thompson
WINNIPEG
Steinbach
Fort Frances
KAPUSKASING
IROQUOIS FALLS
TIMMINS
Rouyn
Haileybury
Dolbeau
Roberval
QUEBEC
Trois-Rivieres
Raudon
GRANBY
MONTREAL
OTTAWA
Pembroke
Swanton
CORNWALL
Iroquois
Morristown
SUDBURY
NORTH BAY
Nairn
Parry Sound
Tweed
Lindsay
Port Perry
TORONTO
Durham
Arthur
Guelph
Stratford
Norwich
St Thomas
0
150
300
450 km

5.4.2.5 Linking Projects to Asset Management Process Outcomes

FFPC's asset management process (Steps 1 to 4) by the nature of its design, identifies and prioritizes system renewal activities. FFPC has transitioned from a zone approach such as "West Feeder Upgrade" to a componentized asset replacement approach such as "Transformer Replacements" based on asset class. The management of asset lifecycles with respect to age, condition, and likelihood of failure account for approximately two-thirds (including General Plant) of all of FFPC's planned investments over the 2014 to 2018 forecast period. As per FFPC's asset management process, "Adjusted End-of-Life" (AEOL) dates drive planning and investment activities. The following asset counts and associated replacement costs are based on FFPC's AEOL profile and represent significant outputs:

Asset Class	Planned # / Meters of Replacements/Refurbishments Between 2014 and 2018 Based on AEOL Analysis	Total Estimated Replacement/Refurbishment Cost for Period 2014 to 2018
Fully Dressed Wood Poles	220	**$ 649,638**
OH Line Switches	1	**$ 28,000**
OH Transformers	116	**$ 491,617**
Station Independent Breakers	1	**$ 150,000**
Primary TR XLPE Cables in Duct	8750	**$ 294,020**
Pad-Mounted Transformers (Single Phase)	35	**$ 368,761**
Pad-Mounted Transformers (Three Phase)	7	**$ 147,163**
Trucks & Buckets	3	**$ 328,000**
Trailers	2	**$ 75,000**
Total		$ 2,532,199

FFPC refines identified system renewal activities based on budget envelopes, work force and resource considerations, seasonal weather considerations, material acquisition lead times, as well as the degree to which other corporate objectives are met.

5.4.2.6 Analysis of Capital System Renewal (including General Plant) Budget Allocations

FFPC has adopted a capital reinvestment strategy that is dictated by the properties of its asset base. The investment into a GIS system has enabled the creation of a "bottom up" asset management process and capital investment plan, which are aligned with the physical properties of the assets managed. FFPC has attained improved oversight of its assets to enable effective and efficient long range planning. Of the total planned Capital Investment Amount of $3,522,205 over the 2014 to 2018 planning period, $2,775,966 or 78.8% are allocated towards the renewal of distribution and general plant.

FFPC has established ideal asset class replacement rates which are based on the asset count within each asset class, and the expected service life for each asset type. Dividing the total asset class count by the expected service life of the asset class, establishes a normalized or ideal asset class replacement rate.

This asset class replacement rate would be the replacement rate for an evenly distributed asset population, over the period of one lifecycle.

If FFPC were to adopt the minimum useful life values for all assets owned as determined in the "Kinectrics Report", FFPC would need to reinvest $1.14 million annually to sustain the asset replacement rate. If FFPC were to adopt the maximum useful life values for all assets owned as determined in the "Kinectrics Report", FFPC would need to reinvest $0.52 million annually to sustain the asset replacement rate.

Using the TUL values determined in the "Kinectrics Report" as an industry benchmark, FFPC would need to reinvest $0.739 million annually to sustain the asset replacement rate. FFPC's asset management process has allowed FFPC to base its budget benchmark on the "Adjusted End-of-Life" (AEOL) profile resulting in slightly longer useful service lives. Longer useful service lives were achieved due to optimizing asset lifecycles, and the results of asset inspections and condition tests that warrant the extensions. Based on the AEOL profile, FFPC needs to reinvest $0.618 million annually to keep pace with the overall asset deterioration rate. Capital investment needs of FFPC's transformer station are sporadic in nature, therefore FFPC has adjusted its ideal reinvestment rate target by only including actual planned capital expenditures over the planning period. As such, FFPC's ideal annual reinvestment rate is reduced to $568,857, which FFPC has adopted as its annual benchmark for System Renewal investments (including General Plant renewals). FFPC hopes to achieve a 2.4% overall cost reduction through improved planning and has set its actual 2014 to 2018 average budget allocation to $555,193. FFPC's asset class age profiles are not evenly distributed, resulting in FFPC facing a "tidal wave" effect over the forecast period. As such, the average annual planned System Renewal (including General Plant) investments of $555,193 are minimalistic and are viewed as essential as opposed to discretionary.

The following tables summarize planned System Renewal capital expenditures over the 2014 to 2018 planning horizon, based on assets that were identified to be at the end of their useful service life, as per outputs of Step 4 of the asset management process. Capital expenditures driven by other investment drivers such as the elimination of LTLT's, Customer Preference or Renewable Enabling Improvements are not included in this summary. The table also illustrates the Useful Life and Reinvestment Need analysis for each asset category. Various reinvestment needs boundaries are illustrated representing various adoptions of useful service life philosophies, such as the "Kinectrics Report's" MIN UL, TUL, MAX UL as well as FFPC'S adopted UL. Lastly, the table also illustrates budgeted reinvestment amount by asset class.

FFPC Asset Summary, Useful Life Assessment, Investment Boundaries and Capital Budget Allocations

		Asset Details			FFPC Assets			Kinectrics Useful Life			Useful Life Assessment					Reinvestment Needs Assessment					Capital Budget Allocation		
Parent*	#	Category| Component | Type			Count	Units	Average Age of Population (Years)	MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to Kinectrics TUL	% Remaining Useful Life Relative to Kinectrics TUL	Remaining Useful Life Relative to FFPC Adopted UL	% Remaining Useful Life Relative To FFPC Adopted UL	Total Replacement Cost of Asset Group	Average Annual Reinvestment Need Based on Kinectrics Min UL	Average Annual Reinvestment Need Based on Kinectrics TUL	Average Annual Reinvestment Need Based on Kinectrics Max UL	Average Annual Reinvestment Need Based on FFPC Adopted UL	Asset Management Process (Step 4) 2014 - 2018 Total Capital Allocation	Average Annual Capital Allocation (2044 to 2018)	% of Total DS Plan Capital Expenditures
OH	1	Fully Dressed Wood Poles	Overall		1776	Each	21.79	35	45	75	45	23.21	51.58%	23.21	51.6%	$ 5,850,761	$ 167,165	$ 130,017	$ 78,010	**$ 130,017**	$ 679,638	$ 135,928	19.3%
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	2	Fully Dressed Concrete Poles	Overall		N/A			50	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	3	Fully Dressed Steel Poles	Overall		N/A			60	60	80													
			Cross Arm	Wood	N/A			20	40	55													
				Steel	N/A			30	70	95													
	4	OH Line Switch (Expressed as sets of 3 Phase Switches)			35	Each	24.34	30	45	55	45	20.66	45.90%	20.66	45.9%	$ 254,409	$ 8,480	$ 5,654	$ 4,626	**$ 5,654**	$ 32,500	$ 6,500	0.9%
	5	OH Line Switch Motor			N/A			15	25	25													
	6	OH Line Switch RTU			N/A			15	20	20													
	7	OH Integral Switches			N/A			35	45	60													
	8	OH Conductors	Primary Conductor		224.2	km	33.77	50	60	75	60	26.23	43.72%	26.23	43.7%	$ 676,409	$ 13,528	$ 11,273	$ 9,019	**$ 11,273**	$ -	$ -	0.0%
			Secondary Conductor		114.8	km	28.00	25	35	40	40	7.00	20.00%	12.00	30.0%	$ 1,033,603	$ 41,344	$ 29,532	$ 25,840	**$ 25,840**	$ 50,000	$ 10,000	1.4%
	9	OH Transformers			629	Each	28.79	30	40	60	40	11.21	28.02%	11.21	28.0%	$ 2,751,265	$ 91,709	$ 68,782	$ 45,854	**$ 68,782**	$ 491,617	$ 98,323	14.0%
	10	OH Shunt Capacitor Banks			N/A			25	30	40													
	11	Reclosers			N/A			25	40	55													
TS & MS	12	Power Transformers	Overall		2	Each	38.00	30	45	60	58	7.00	15.56%	20.00	34.5%	$ 1,930,575	$ 64,352	$ 42,902	$ 32,176	**$ 33,286**	$ -	$ -	0.0%
			Bushing		12	Each	38.00	10	20	30	44	0.00	0.00%	6.00	13.6%	$ 68,351	$ 6,835	$ 3,418	$ 2,278	**$ 1,553**	$ -	$ -	0.0%
			Tap Changer		2	Each	38.00	20	30	60	58	0.00	0.00%	20.00	34.5%	$ 1,127,792	$ 56,390	$ 37,593	$ 18,797	**$ 19,445**	$ -	$ -	0.0%
	13	Station Service Transformer			1	Each	40.00	30	45	55	45	5.00	11.11%	5.00	11.1%	$ 8,544	$ 285	$ 190	$ 155	**$ 190**	$ -	$ -	0.0%
	14	Station Grounding Transformer			N/A	Each		30	40	40													
	15	Station DC System	Overall		2	Each	23.00	10	20	30	29	0.00	0.00%	6.00	20.7%	$ 85,439	$ 8,544	$ 4,272	$ 2,848	**$ 2,946**	$ -	$ -	0.0%
			Battery Bank		2	Each	9.00	10	15	15	15	6.00	40.00%	6.00	40.0%	$ 51,263	$ 5,126	$ 3,418	$ 3,418	**$ 3,418**	$ 10,000	$ 2,000	0.3%
			Charger		2	Each	23.00	20	20	30	29	0.00	0.00%	6.00	20.7%	$ 34,176	$ 1,709	$ 1,709	$ 1,139	**$ 1,178**	$ 22,000	$ 4,400	0.6%
	16	Station Metal Clad Switchgear	Overall		11	Each	45.00	30	40	60	62	0.00	0.00%	17.00	27.4%	$ 845,844	$ 28,195	$ 21,146	$ 14,097	**$ 13,643**	$ -	$ -	0.0%
			Removable Breaker		11	Each	45.00	25	40	60	62	0.00	0.00%	17.00	27.4%	$ 205,053	$ 8,202	$ 5,126	$ 3,418	**$ 3,307**	$ -	$ -	0.0%
	17	Station Independent Breakers			1	Each	67.00	35	45	65	69	0.00	0.00%	2.00	2.9%	$ 138,411	$ 3,955	$ 3,076	$ 2,129	**$ 2,006**	$ 150,000	$ 30,000	4.3%
	18	Station Switch			5	Each	41.00	30	50	60	62	9.00	18.00%	21.00	33.9%	$ 68,351	$ 2,278	$ 1,367	$ 1,139	**$ 1,102**	$ -	$ -	0.0%
	19	Electromechanical Relays			34	Each	36.00	25	35	50	45	0.00	0.00%	9.00	20.0%	$ 131,576	$ 5,263	$ 3,759	$ 2,632	**$ 2,924**	$ -	$ -	0.0%
	20	Solid State Relays			N/A	Each		10	30	45													
	21	Digital & Numeric Relays			8	Each	1.50	15	20	20	20	18.50	92.50%	18.50	92.5%	$ 56,390	$ 3,759	$ 2,819	$ 2,819	**$ 2,819**	$ -	$ -	0.0%
	22	Rigid Busbars			3	Each	36.00	30	55	60	62	19.00	34.55%	26.00	41.9%	$ 42,719	$ 1,424	$ 777	$ 712	**$ 689**	$ -	$ -	0.0%
	23	Steel Structure			1	Each	36.00	35	50	90	62	14.00	28.00%	26.00	41.9%	$ 136,702	$ 3,906	$ 2,734	$ 1,519	**$ 2,205**	$ 25,000	$ 5,000	0.7%
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			N/A			60	65	75													
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			N/A			20	25	25													
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			N/A			20	25	30													

	27	Primary Non-TR XLPE Cables in Duct		N/A			20	25	30													
	28	Primary TR XLPE Cables Direct Buried		N/A			25	30	35													
	29	Primary TR XLPE Cables in Duct		30.7	km	27.07	35	40	55	40	12.93	32.32%	12.93	32.3%	$ 931,695	$ 26,620	$ 23,292	$ 16,940	**$ 23,292**	$ 180,537	$ 36,107	5.1%
	30	Secondary PILC Cables		N/A			70	75	80													
	31	Secondary Cables Direct Buried		3.8	km	28.00	25	35	40	35	7.00	20.00%	7.00	20.0%	$ 68,366	$ 2,735	$ 1,953	$ 1,709	**$ 1,953**	$ 10,000	$ 2,000	0.3%
	32	Secondary Cables in Duct		N/A			35	40	60													
	33	Network Transformers	Overall	N/A			20	35	50													
			Protector	N/A			20	35	40													
	34	Pad-Mounted Transformers	Single Phase	215	Each	27.70	25	40	45	40	12.30	30.74%	12.30	30.7%	$ 2,218,967	$ 88,759	$ 55,474	$ 49,310	**$ 55,474**	$ 368,761	$ 73,752	10.5%
			Three Phase	38	Each	20.05	25	40	45	40	19.95	49.87%	19.95	49.9%	$ 808,033	$ 32,321	$ 20,201	$ 17,956	**$ 20,201**	$ 147,163	$ 29,433	4.2%
	35	Submersible/Vault Transformers		N/A			25	35	45													
	36	UG Foundation		170	Each	27.52	35	55	70	80	27.48	49.97%	52.48	65.6%	$ 814,956	$ 23,284	$ 14,817	$ 11,642	**$ 10,187**	$ -	$ -	0.0%
	37	UG Vaults	Overall	N/A			40	60	80													
			Roof	N/A			20	30	45													
	38	UG Vault Switches		N/A			20	35	50													
	39	Pad-Mounted Switchgear		N/A			20	30	45													
	40	Ducts		23.5	km	27.95	30	50	85	80	22.05	44.10%	52.05	65.1%	$ 322,801	$ 10,760	$ 6,456	$ 3,798	**$ 4,035**	$ -	$ -	0.0%
	41	Concrete Encased Duct Banks		1.9	km	33.46	35	55	80	80	21.54	39.16%	46.54	58.2%	$ 712,998	$ 20,371	$ 12,964	$ 8,912	**$ 8,912**	$ -	$ -	0.0%
	42	Cable Chambers		5	Each	20.40	50	60	80	60	39.60	66.00%	39.60	66.0%	$ 35,000	$ 700	$ 583	$ 438	**$ 583**	$ -	$ -	0.0%
S	43	Remote SCADA		N/A			15	20	30													
	1	Office Equipment		Unknown	Each	Unknown	*5*	*10.0*	*15*	15	Unknown	Unknown	Unknown	Unknown	$ 60,000	$ 12,000	$ 6,000	$ 4,000	**$ 4,000**	$ 15,000	$ 3,000	0.4%
	2	Vehicles	Trucks & Buckets	7	Each	8.00	*5*	*10.0*	*15*	15	2.00	20.00%	7.00	46.7%	$ 801,000	$ 160,200	$ 80,100	$ 53,400	**$ 53,400**	$ 328,000	$ 65,600	9.3%
			Trailers	2	Each	26.00	*5*	*12.5*	*20*	20	0.00	0.00%	0.00	0.0%	$ 75,000	$ 15,000	$ 6,000	$ 3,750	**$ 3,750**	$ 75,000	$ 15,000	2.1%
			Vans	N/A			*5*	*7.5*	*10*													
	3	Administrative Buildings		1	Each	45.00	*50*	*62.5*	*75*	75	17.50	28.00%	30.00	40.0%	$ 550,000	$ 11,000	$ 8,800	$ 7,333	**$ 7,333**	$ 65,000	$ 13,000	1.8%
	4	Leasehold Improvements (Generator)		1	Each	5.00	*20*	*20.0*	*20*	20	15.00	75.00%	15.00	75.0%	$ 86,122	$ 4,306	$ 4,306	$ 4,306	**$ 4,306**	$ -	$ -	0.0%
	5	Station Buildings	Station Buildings	2	Each	39.0	*50*	*62.5*	*75*	62	23.50	37.60%	23.00	37.1%	$ 368,375	$ 7,368	$ 5,894	$ 4,912	**$ 5,942**	$ 31,000	$ 6,200	0.9%
			Parking	1	Each	24.00	*25*	*27.5*	*30*	30	3.50	12.73%	6.00	20.0%	$ 5,000	$ 200	$ 182	$ 167	**$ 167**	$ -	$ -	0.0%
			Fence	1	Each	42.00	*25*	*42.5*	*60*	62	0.50	1.18%	20.00	32.3%	$ 22,500	$ 900	$ 529	$ 375	**$ 363**	$ -	$ -	0.0%
			Roof	2	Each	39.00	*30*	*30.0*	*30*	40	0.00	0.00%	1.00	2.5%	$ 30,000	$ 1,000	$ 1,000	$ 1,000	**$ 750**	$ -	$ -	0.0%
	6	Computer Equipment	Hardware	Unknown	Each	Unknown	*3*	*4.0*	*5*	5	Unknown	Unknown	Unknown	Unknown	$ 32,000	$ 10,667	$ 8,000	$ 6,400	**$ 6,400**	$ 35,500	$ 7,100	1.0%
			Software	Unknown	Each	Unknown	*2*	*3.5*	*5*	5	Unknown	Unknown	Unknown	Unknown	$ 76,000	$ 38,000	$ 21,714	$ 15,200	**$ 15,200**	$ -	$ -	0.0%
General Plant	7	Equipment	Power Operated	Unknown	Each	Unknown	*5*	*7.5*	*10*	7	Unknown	Unknown	Unknown	Unknown	$ 7,000	$ 1,400	$ 933	$ 700	**$ 1,000**	$ 30,500	$ 6,100	0.9%
			Stores	N/A			*5*	*7.5*	*10*													
			Tools, Shop, Garage Equip.	Unknown	Each	Unknown	*5*	*7.5*	*10*	10	Unknown	Unknown	Unknown	Unknown	$ 10,000	$ 2,000	$ 1,333	$ 1,000	**$ 1,000**			
			Measurement & Testing Equip	Unknown	Each	Unknown	*5*	*7.5*	*10*	8	Unknown	Unknown	Unknown	Unknown	$ 65,000	$ 13,000	$ 8,667	$ 6,500	**$ 8,125**			
	8	Communication	Towers	N/A			*60*	*65.0*	*70*													
			Wireless	Unknown	Each	Unknown	*2*	*6.0*	*10*	10	Unknown	Unknown	Unknown	Unknown	$ 9,600	$ 4,800	$ 1,600	$ 960	**$ 960**	$ -	$ -	0.0%
	9	Residential Energy Meters		N/A			*25*	*30.0*	*35*													
	10	Industrial/Commercial Energy Meters		N/A			*25*	*30.0*	*35*													
	11	Wholesale Energy Meters		2	Each	5.00	*15*	*22.5*	*30*	9	17.50	77.78%	4.00	44.4%	$ 18,000	$ 1,200	$ 800	$ 600	**$ 2,000**	$ -	$ -	0.0%
	12	Current & Potential Transformer (CT & PT)		479	Each	Unknown	*35*	*42.5*	*50*	40	Unknown	Unknown	Unknown	Unknown	$ 85,262	$ 2,436	$ 2,006	$ 1,705	**$ 2,132**	$ 12,500	$ 2,500	0.4%
	13	Smart Meters		3966	Each	4.92	*5*	*10.0*	*15*	15	5.08	50.76%	10.08	67.2%	$ 650,543	$ 130,109	$ 65,054	$ 43,370	**$ 43,370**	$ 16,250	$ 3,250	0.5%
	14	Repeaters - Smart Metering		N/A			*10*	*12.5*	*15*													
	15	Data Collectors - Smart Metering		7	Each	5.00	*15*	*17.5*	*20*	17	12.50	71.43%	12.00	70.6%	$ 17,972	$ 1,198	$ 1,027	$ 899	**$ 1,057**	$ -	$ -	0.0%
Totals															$ 24,379,820.51	$ 1,144,782	$ 739,250	$ 519,907	**$ 618,169**	**$ 2,775,966**	**$ 555,193**	**78.8%**

5.4.2.7 Customer Engagement Mechanisms

FFPC conducted an extensive customer survey throughout the summer of 2013 to solicit customer feedback. A survey was mailed out to all of FFPC's customers in all rate classes via a bill insert. This approach gave all customers the equal opportunity to participate in the survey. To support this initiative, FFPC also launched an extensive newspaper advertising campaign to encourage participation.

FFPC received an overwhelming positive response to the survey. Almost 10% of FFPC's entire customer base completed and returned surveys for analysis. FFPC survey found that customers are very pleased with FFPC's performance overall. It is worth noting that under the "Overall Satisfaction" portion of the survey, only 1 out of 345 responses received, indicated a degree of dissatisfaction.

The survey results offered considerable insight into customer satisfaction, priorities and preferences. Based on the survey findings, FFPC is planning on implement the following projects over the 2014 to 2018 planning horizon.

1 - Mass customer contact system (outage notification etc):	2015 Rollout
2 - Transition to true calendar monthly billing:	2014 Rollout
3 - Offering Electronic Billing:	2014 Rollout
4 - Online access to consumption and billing data:	2014 Rollout
5 - Outage Management System:	2017 Rollout
6 - Maintaining current reliability performance levels	Ongoing

For detailed information regarding customer engagement activities refer to Section 5.2.2.4, 5.2.3.5, 5.4.1.8.a, as well as to Appendix 3 for a copy of FFPC's customer survey and corresponding analysis.

5.4.2.8 Distributor Owned Renewable Generation Projects

FFPC has investigated the feasibility of investing in distributor-owned renewable generation throughout FFPC's licensed service territory, as it is very conducive to hydroelectric and photovoltaic generation. At the time of preparing this DS Plan, FFPC has not formally proceeded with the development of any such projects. For details regarding FFPC's capability to accommodate renewable generation and for FFPC's renewable generation enabling investment plan, refer to section 5.4.3

5.4.3 FFPC System Capability Assessment for Renewable Energy Generation

5.4.3.1 Third Party Assessment Report Highlights

FFPC contracted Siemens Canada to perform a system capability assessment on FFPC's Fort Francs MTS Transformer station. The following assessments are based on the findings contained within the Siemens Assessment Report.

Connection of renewable energy generation facilities, (generation), within FFPC's existing distribution system requires suitable connection points. The proposed size and type of generation determines if modifications to the existing distribution system or the installation of a new dedicated feeder tied directly into the Fort Frances MTS Transformer Station (FFMTS) are required. Protection requirements within the transformer station, distribution system and new generating facility are determined based on the size of generation proposed.

In preparation of accommodating the connection of generation facilities within the distribution system, FFPC must within its transformer station, implement new protection components to ensure the safety of people, both private citizens and electrical workers, and equipment. The existing transformer station instrumentation does not give FFPC the ability to accurately define constraints with confidence as there is no metering or relaying from which time stamped measurement data or event data can be obtained. All current measurements are from analog gauges that do not have clocks or data logging capabilities.

5.4.3.2 Existing Transformer Station Protections

The existing protections within the Fort Frances MTS Transformer station are single function electro-mechanical relays. With the installation of almost any generation within the distribution system, added protection will be required. Advances with protection technology since the original protections in the transformer station were installed, will make the addition of single function relays un-economical. New relaying, which may or may not include load side voltage monitoring and/or generator breaker status monitoring, will be required depending on the size of the new generation being installed.

Presently there are auto-reclosure relays on the feeder breakers. Re-closure relays without monitoring the feeder, either by the generator breaker status or voltage monitoring, may allow the closing of a feeder breaker in the main transformer station onto an energized line out of synchronization. This is not a desirable situation for the distributor or generation facility and could cause significant damage to equipment and/or personnel.

The existing auto-reclosure protection configuration is also not configured for reverse power flow in the event that feeder generation exceeds feeder loading. As such, feeder constraints are currently set to relatively conservative constraints until they can be more accurately defined with the addition of monitoring instrumentation.

5.4.3.3 Generator Protections

The required protections within any new large scale generation facility will be outlined in a document to be prepared as/when required. The size of any new generation and the associated possible impact on the existing system will determine the required protections that the new generating facility will be required to install.

The IEEE Guide for AC Generator Protection and other distributor's generator grid connection requirements will be reviewed and used to prepare a comprehensive outline of requirements for any new generation. Typically new generator protection relays contain enough protective elements to provide full protection for the new generator, as well as for the distribution system. If the new generation facility is comprised of more than one generator being tied into the system, a full review of the main interconnecting points will have to be taken.

To date FFPC has received several inquiries from large scale generator applicants but no formal applications have been submitted to FFPC.

5.4.3.4 Tie In Points

Within the transformer station there are presently 6 x 12.47 kV feeders. Each feeder has overload protection set at 480 amperes, which is equivalent to approximately 10 MW of power. If the new generation facility is located near a point where the distribution feeder ampacity has not been stepped down (smaller conductors), it could be tied directly to these locations along any of the six feeders. Another option is to tie the generator directly into the switchgear located within FFMTS. There are presently 2 spare 12.47 kV breakers which could be utilized; however, this would eliminate one spare, and thereby limit system redundancy.

Another option would be to double up one feeder. This would involve more work in the transformer station switchgear but this configuration would only use one breaker to supply a load and be the tie in point for the new generation facility.

Where and how any new generation is to be tied into the existing system will be solely dependent on the size and technology of the generation facility. When an application for connection is made and the size becomes know, a full review of the listed options with associated costs would be made.

5.4.3.5 Generation Up To 10 MW

Generation of up to 10 MW would likely be connected directly into the existing 12.47 kV distribution system or in other words at the feeder level. Provided that the ampacity of the distribution system is suitable, no issues are seen at the feeder level. The closer a generator is located to a transformer station, the greater the available generation connection capacity. It should be noted; however, that photovoltaic generation has an additional capacity limitation that is equivalent to 30% of a feeder's minimum load.

5.4.3.6 Generation of 10 MW and Larger

Larger amounts of generation, where the connected ampacity exceeds any present distribution capacity, would need either a new dedicated feeder, or system upgrades to existing feeders. As FFPC has not received any formal applications from generators in this category, no feeder expansions or upgrades have been planned.

5.4.3.7 Transmitting Power to 115 kV grid

Once new generation is tied into the existing 12.47 kV distribution system, the power not absorbed by the existing 12.47 kV load would have to be exported onto the 115 kV grid. The worst case scenario for power flow would be no existing load on the lowest rated transformer, (both transformers are rated at 20/25 MVA). Based on this worst case scenario, the largest generation capacity that can be tied directly into the system through either transformer would be approximately 25 MW at unity power factor. However, based on the current loading and assuming equal division of loads between the two transformers located at FFMTS, the allowable total new generation can be increased beyond the 25 MW as the load could be shared between the two station transformers. Although the absolute nameplate limitation of each transformer is 25 MVA, current constraints have been set according to the industry standard 60% reverse power flow limitation at a 0.9 power factor, which results in a station limitation of 10.8 MW.

5.4.3.8 Protections and Generator Requirements

In general, generator protection is solely determined by the generating facility. If the generating facility it being tied directly onto FFPC's existing distribution system, FFPC must ensure that any new generation does not negatively impact its existing customers. In order to ensure this, generator tie-in requirements will be needed. These as indicated above, will be prepared on an as needed basis. It should be noted that small scale generators in the microFIT category typically have enough protection built into the inverter and usually no additional protection is required. As part of FFPC's microFIT approval process, inverter protection requirements are verified.

Generator Tie-In Requirements will contain the minimum protective and system monitoring criteria that each generating facility is required to have. Coordination of new protections will be performed by the new generating facility, but submitted and reviewed by FFPC. This is to ensure the new generating facility does not negatively impact the existing system.

5.4.3.9 Applications from Renewable Generators Up to 10 kW

FFPC has experienced successful uptake on the microFIT program offering within its licensed service territory. To date FFPC has been able to accommodate requests for generator connections from all applicants that have filed their "Application for Generator Connections" submission with FFPC, upon

receiving authorization from the OPA to do so. FFPC itself has not had to reject any applications due to any type of constraints to date.

The following is a summary of active microFIT installations within FFPC's licensed service territory:

Summary of Active microFIT Installation Within FFPC's Licensed Service Territory As at June 26, 2013						
OPA Project Reference Number	**Technology**	**Capacity (kW)**	**Inverter Rating (kW)**	**LDC Connection Date**	**Feeder (Dx)**	**Application Status**
FIT-MCT42NH	Solar PV (Rooftop)	5.445	4.9	12/30/2010	West (A)	Contract Offer - Accepted
FIT-MZG433B	Solar PV (Rooftop)	10	9.9	11/08/2011	Victoria (E)	Contract Offer - Accepted
FIT-MCFUYIA	Solar PV (Rooftop)	10	10	11/08/2011	East (G)	Contract Offer - Accepted
FIT-MRCR6IY	Solar PV (Rooftop)	10	10	09/22/2011	West (A)	Contract Offer - Accepted
FIT-MFWPEWJ	Solar PV (Rooftop)	10	9.9	11/08/2011	Crowe (F)	Contract Offer - Accepted
***FIT-MQ4KUXM**	*Solar PV (Rooftop)*	*10*	*10*	*10/24/2011*	*Third (B)*	*Contract Offer - Rejected*
FIT-MA6GGB6	Solar PV (Rooftop)	7.905	6.665	02/28/2013	West (A)	Contract Offer - Accepted
FIT-MZ874TZ	Solar PV (Rooftop)	10	10	03/20/2013	West (A)	Contract Offer - Accepted
Total		**73.35**	**71.365**			

*Note: One microFIT installation failed to meet OPA contract acceptance requirements and as such the generation facility is built but is currently not operational. FFPC has been informed that this project may resume production under a new contract in the near future.

Please note that most solar photovoltaic (PV) installations appear to have a higher generation capacity when arithmetically adding up the wattage of all panels; however, the output of these installations is limited to the rating of the inverter which dictates the "nameplate rating" of the system. FFPC currently has 71.365 kW of microFIT generation online based on the summation of inverter nameplate ratings.

5.4.3.10 Applications from Renewable Generators over 10 kW

To date FFPC has received one application for a renewable generation system that is over 10 kW in size. The application received was for a 100 kW capacity allocation exempt rooftop solar system. FFPC was able to accommodate this application and the project was commissioned in the summer of 2011. Since this time, FFPC has had several applicants express interest in installing FIT projects; however, none have brought forward a formal application to FFPC's attention. FFPC has; however, received several inquiries from microFIT and FIT project applicants looking to relocate their projects from constrained service territories to FFPC's licensed service territory.

Summary of Active FIT Installations Within FFPC's Licensed Service Territory As at June 26, 2013						
OPA Project Reference Number	**Technology**	**Capacity (kW)**	**Inverter Rating (kW)**	**LDC Connection Date**	**Feeder (Dx)**	**Application Status**
FIT-FPUWGLU	Solar PV (Rooftop)	119.15	100	09/06/2011	West (A)	Contract Offer - Accepted
Total		**119.15**	**100**			

5.4.3.11 Forecasted Renewable Generation Connections 2014 to 2018

FFPC has consulted with several microFIT applicants regarding connecting renewable generation onto FFPC's distribution system. FFPC has performed a connection analysis on the following microFIT applications and expects that the following projects will come online throughout the fall of 2013.

Summary of Active microFIT Applications Within FFPC's Licensed Service Territory As at June 26, 2013						
OPA Project Reference Number	**Technology**	**Capacity (kW)**	**Inverter Rating (kw)**	**LDC Connection Date**	**Feeder (Dx)**	**Application Status**
FIT-MNVMBQM	Solar PV (Rooftop)	10	*5.16*	TBD	Crowe (F)	Pending Connection
FIT-MATG6YW	Solar PV (Rooftop)	6	6	TBD	*Crowe (F)*	Submitted
FIT-M4N72GJ	Solar PV (Rooftop)	10	*10*	TBD	*West (A)*	LDC has issued the Offer to Connect
Total		**26**	**21.16**			

5.4.3.12 OPA Relocation Program Inquiries

FFPC has been contacted by microFIT and FIT applicants who are looking to relocate their generation project to within FFPC's licensed distribution service territory under the OPA's Relocation Program. The applicants of the following microFIT projects have formally approached FFPC to relocate their constrained project to within FFPC licensed service territory:

Summary of microFIT Relocation Requests to within FFPC's Licensed Service Territory As at June 26, 2013						
OPA Project Reference Number	**Technology**	**Capacity (kW)**	**Inverter Rating (kw)**	**LDC Connection Date**	**Feeder (Dx)**	**Application Status**
FIT-M8326BE	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MUC16VW	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M32WKMD	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M6FPQCX	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M7ZPXJV	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MICZ2FI	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MM6ZWYB	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MVRRKE8	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MW9JXTY	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MCZHE3E	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MFPT2ZN	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MWBUTFI	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MR3UHUJ	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M39DQHT	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M3ZJ4TB	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M4AI24V	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M4RA9YZ	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M838TPP	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M8CIUZW	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M98PJCF	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MAW6P4I	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MFCX6Z4	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MGUEVBH	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MJMC2M8	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MRY2JKH	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MU6T9HZ	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MZDTUFG	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MTE9JFR	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MUN9EP6	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-M9Z2KAH	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MBGN96P	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MCMBV94	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MI9T26Q	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MKA62PB	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MM3J8AA	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
FIT-MU88QJZ	Solar PV (Ground)	TBD	10	TBD	West (A)	Unknown to LDC
Total		**0**	**360**			

FFPC has also been approached about combined relocation projects having generation capacity of up to 340 kW. FFPC notes that it has the capacity to accommodate these projects; however, FFPC notes that it needs to proceed with its planned renewable generation enabling projects as discussed throughout this submission to improve protection and monitoring of feeders and mains. As at the time of preparing this submission, two of the above relocation projects are in the construction phase, after receiving OPA and FFPC approval to proceed.

5.4.3.13 FFPC Distributed Generation Operating Constraints

At the time of preparing this submission FFPC had to rely on spot testing in determining how FFPC's load from its transformer station is distributed among the six feeders, as individual feeder metering data is not yet available. The total station load was determined using wholesale metering data. The following table illustrates FFPC's maximum and minimum feeder loading, as well as total system loading based on 2012 yearend data. It should be noted that the "Min Load (kW)" criteria corresponds to FFPC's reverse power flow constraints and that 30% of this value also corresponds to the limitation of PV generation on any feeder. With improved monitoring, FFPC expects these limits to increase due to several factors including the consideration that the 30% limitation should only apply during daytime hours, when solar systems produce power (minimum flows typically occur throughout the night).

FFPC Distribution System Load Profile Based on 2012 Year-End Data				
FFMTS Transformer	**FFMTS Feeder**	**% System Total Load**	**Max Load (kW)**	**Min Load (kW)**
T1	West Feeder (A)	19.9%	3,235	869
	Mowat Feeder (D)	11.6%	1,897	509
	East Feeder (G)	14.0%	2,287	614
T1 Subtotal (kW)			**7,419**	**1,993**
T2	Third Street Feeder (B)	15.1%	2,464	662
	Victoria Feeder (E)	20.4%	3,319	891
	Crowe Feeder (F)	18.9%	3,087	829
T2 Subtotal (kW)			**8,869**	**2,382**
System Total (kW)		**100.0%**	**16,288**	**4,375**

As can be seen from the table above, under normal operating conditions, the reverse power flow state will arise when the generation exceeds load at the feeder level, the station transformer level or the system level. FFPC has used the reverse power flow state to define absolute generation constraints as system upgrades are required to accommodate reverse power flows.

Further to this, the maximum allowable amount of PV generation should not exceed one third of the feeder minimum load, as stated in the Institute of Electrical and Electronics Engineers (IEEE) standard IEEE1547 *Standard for Interconnecting Distributed Resources with Electrics Power Systems.* Under this set of criteria FFPC's photovoltaic generation limits by feeder are:

FFPC Feeder Constraints Based on 30% Minimum Feeder Load PV Limitation Criteria			
FFMTS Feeder	**30% PV Min Feeder Loading Limitation (kW)**	**Current PV Generation Level (kW)**	**Remaining Feeder PV Capacity (kW)**
West Feeder (A)	261	131.6	129
Mowat Feeder (D)	153	0	153
East Feeder (G)	184	10	174
Third Street Feeder (B)	199	10	189
Victoria Feeder (E)	267	9.9	258
Crowe Feeder (F)	249	9.9	239
Total kW	1,313	171	1,141

As discussed in the third party assessment section, FFPC's feeders all have an ultimate ampacity constraint of 10 MW, which is much higher than any other constraint and will therefore likely not be encountered.

The base thermal capacity for the FFMTS station and buses has been defined using the 60% reverse power flow limitation rule (relative to lowest power transformer thermal rating which in this case is 20 MVA) assuming a power factor of 0.9. FFMTS is therefore rated at having a 10.8 MW renewable generation connection capacity limit as per the following:

Station Capacity Limit = Lowest Station Transformer Thermal Rating in MVA x 60% x 0.9 Power Factor

= 20 x 0.6 x 0.9 = 10.8 MW

It should also be noted that this limit can easily be increased with more intelligence and automation at FFMTS. It could easily be doubled to 21.6 MW if protection was coordinated with Generation Facilities.

FFPC's most stringent constraints correspond to the maximum suggested photovoltaic generation amount on any feeder, relative to the minimum feeder load as per the above table. Again these constraints are expected to be relaxed with improved feeder metering/relaying as the constraints can be refined to align with daylight hours.

In summation given FFPC's current circumstance with limited metering and protection, FFPC can accommodate:

- Up to 10.8 MW of renewable generation at FFMTS based on station transformer constraints
- Up to 1.141 MW of additional photovoltaic generation
- Up to 10 MW of renewable generation on any feeder based on feeder ampacity limitations
- For Reverse flow limitation please refer to the "Minimum Load" listing above

5.4.3.14 Load Forecast With Respect to Supply Point Loading

Please note that the intent of this load forecast is to project electrical loading at FFPC's supply point, and not for the purpose of projecting operating revenue. This load forecast is based on the impact that Renewable Generation connections, CDM and the local economy are projected to have on FFPC's supply point. For the weather normalized load forecast used to establish operating revenue please refer to "Exhibit 3, Tab 2, Schedule 1".

FFPC has a single supply point called "2201F1B", which is the incoming 115kV supply to FFPC's "Fort Frances MTS" transformer station, from HONI's "Fort Frances TS" transformer station.

FFPC is expecting to see reductions in demand and in the volume of electricity delivered through this single supply point "2201F1B" in the near future, due to the effects of conservation and demand management programs, the state of the local economy, as well as due to offsetting distributed generation coming online.

5.4.3.15 Reductions Due to Offsetting Renewable Generation

To date all of FFPC's distributed generation systems are either ground-mounted or rooftop photovoltaic systems. FFPC has calculated the following generation profile based on the actual total volume of generation produced from the PV systems, divided by the total nameplate capacity of the corresponding generation systems. It is worth noting that winter time PV generation is greatly affected by snow loads, and as such, FFPC has experienced large reductions in PV generation due to large accumulations of winter snow deposits. The following table illustrates the average anticipated kWh of generation for every 1 kW of installed PV generation capacity based on the 2012 test year data.

FFPC PV Generation Profile based on 2012 Test Year	
Month	KWh/kW
January	22.10
February	39.31
March	98.70
April	151.43
May	147.60
June	180.19
July	172.14
August	156.33
September	116.52
October	57.15
November	27.42
December	8.30
Total	**1177.19**

Multiplying the generation capacity by FFPC's distribution system loss factor of 1.0406 represents the actual volumetric reduction equivalent at FFPC's supply point "2201F1B".

Without considering the impact of the 360 kW PV relocation projects, FFPC anticipates connecting approximately 62.5 kW of renewable generation year-over-year, based on FFPC's average project uptake from years 2011 to 2013. Assuming this average uptake and that PV projects in Northern Ontario are not curtailed, the following table represents FFPC's anticipated renewable generation forecast. The supply point demand reductions correspond to the combined nameplate rating of all PV generating systems as per the column "Total PV Generating Capacity (kW)". Note that FFPC is assuming that future projects come on line mid-year (July 1st).

2013 Projected Renewable Energy Generation				
Month	Total PV Generating Capacity (kW)	Conversion Efficiency (kWh/kW)	Projected Generation (kWh)	Vol. Reduction at Supply Point (kWh)
Jan	144.7	22.10	3,198	3,327.83
Feb	144.7	39.31	5,689	5,919.82
Mar	151.365	98.70	14,940	15,546.39
Apr	161.365	151.43	24,435	25,427.34
May	161.365	147.60	23,818	24,784.77
June	161.365	180.19	29,077	30,257.52
July	161.365	172.14	27,777	28,905.07
Aug	161.365	156.33	25,226	26,250.10
Sept	166.525	116.52	19,403	20,190.55
Oct	176.525	57.15	10,088	10,497.87
Nov	186.525	27.42	5,115	5,322.32
Dec	186.525	8.30	1,548	1,611.00
Total			190,314	198,040.58

2014 Projected Renewable Energy Generation				
Month	Total PV Generating Capacity (kW)	Conversion Efficiency (kWh/kW)	Projected Generation (kWh)	Vol. Reduction at Supply Point (kWh)
Jan	186.525	22.10	4,122	4,289.73
Feb	186.525	39.31	7,333	7,630.92
Mar	186.525	98.70	18,410	19,157.60
Apr	186.525	151.43	28,245	29,391.97
May	186.525	147.60	27,531	28,649.20
June	186.525	180.19	33,611	34,975.26
July	249.025	172.14	42,867	44,607.47
Aug	249.025	156.33	38,930	40,510.22
Sept	249.025	116.52	29,015	30,193.38
Oct	249.025	57.15	14,232	14,809.41
Nov	249.025	27.42	6,828	7,105.70
Dec	249.025	8.30	2,067	2,150.81
Total			253,192	263,471.69

2015 Projected Renewable Energy Generation				
Month	Total PV Generating Capacity (kW)	Conversion Efficiency (kWh/kW)	Projected Generation (kWh)	Vol. Reduction at Supply Point (kWh)
Jan	249.025	22.10	5,504	5,727.11
Feb	249.025	39.31	9,790	10,187.86
Mar	249.025	98.70	24,579	25,576.85
Apr	249.025	151.43	37,710	39,240.51
May	249.025	147.60	36,757	38,248.86
June	249.025	180.19	44,873	46,694.63
July	311.525	172.14	53,626	55,803.00
Aug	311.525	156.33	48,700	50,677.43
Sept	311.525	116.52	36,298	37,771.28
Oct	311.525	57.15	17,803	18,526.26
Nov	311.525	27.42	8,542	8,889.09
Dec	311.525	8.30	2,586	2,690.61
Total			326,767	340,033.48

2016 Projected Renewable Energy Generation				
Month	Total PV Generating Capacity (kW)	Conversion Efficiency (kWh/kW)	Projected Generation (kWh)	Vol. Reduction at Supply Point (kWh)
Jan	311.525	22.10	6,885	7,164.49
Feb	311.525	39.31	12,248	12,744.79
Mar	311.525	98.70	30,748	31,996.10
Apr	311.525	151.43	47,174	49,089.04
May	311.525	147.60	45,982	47,848.51
June	311.525	180.19	56,135	58,413.99
July	374.025	172.14	64,385	66,998.53
Aug	374.025	156.33	58,471	60,844.63
Sept	374.025	116.52	43,580	45,349.18
Oct	374.025	57.15	21,375	22,243.11
Nov	374.025	27.42	10,256	10,672.47
Dec	374.025	8.30	3,104	3,230.42
Total			400,341	416,595.27

2017 Projected Renewable Energy Generation				
Month	Total PV Generating Capacity (kW)	Conversion Efficiency (kWh/kW)	Projected Generation (kWh)	Vol. Reduction at Supply Point (kWh)
Jan	374.025	22.10	8,266	8,601.88
Feb	374.025	39.31	14,705	15,301.73
Mar	374.025	98.70	36,917	38,415.34
Apr	374.025	151.43	56,638	58,937.58
May	374.025	147.60	55,207	57,448.16
June	374.025	180.19	67,397	70,133.35
July	436.525	172.14	75,143	78,194.07
Aug	436.525	156.33	68,241	71,011.84
Sept	436.525	116.52	50,862	52,927.08
Oct	436.525	57.15	24,947	25,959.96
Nov	436.525	27.42	11,970	12,455.85
Dec	436.525	8.30	3,623	3,770.23
Total			473,916	493,157.06

2018 Projected Renewable Energy Generation				
Month	Total PV Generating Capacity (kW)	Conversion Efficiency (kWh/kW)	Projected Generation (kWh)	Vol. Reduction at Supply Point (kWh)
Jan	436.525	22.10	9,648	10,039.26
Feb	436.525	39.31	17,162	17,858.67
Mar	436.525	98.70	43,085	44,834.59
Apr	436.525	151.43	66,102	68,786.11
May	436.525	147.60	64,432	67,047.81
June	436.525	180.19	78,659	81,852.71
July	499.025	172.14	85,902	89,389.60
Aug	499.025	156.33	78,012	81,179.05
Sept	499.025	116.52	58,144	60,504.97
Oct	499.025	57.15	28,519	29,676.81
Nov	499.025	27.42	13,684	14,239.23
Dec	499.025	8.30	4,142	4,310.04
Total			547,491	569,718.85

5.4.3.16 Reductions Due to Conservation and Demand Management

FFPC anticipates being able to achieve its 2011 to 2014 Conservation Targets, which would represent a cumulative volumetric reduction of 3.64 GWh, as well as a 0.61 MW reduction in annual peak demand. FFPC can only project CDM related reductions up to the end of 2014, as FFPC is unsure of CDM program activities beyond that point. Since CDM reductions are achieved at the customer level, corresponding reductions at FFPC's supply point also need to be multiplied by FFPC's loss factor of 1.0406. FFPC anticipates the following reductions:

FFPC CDM Reductions Targets					
Reduction Units	2011 Reduction	2012 Reduction	2013 Reduction	2014 Reduction	Target
kW	23	267	427	610	610
kWh	140,959	951,041	1,092,000	1,456,000	3,640,000

FFPC Supply Point Reductions Due To CDM Initiatives				
Reduction Units	2011 Reduction	2012 Reduction	2013 Reduction	2014 Reduction
kW	24	278	444	635
kWh	107,133	564,725	1,178,437	1,789,706

5.4.3.17 Reductions Due to the State of the Local Economy

The Town of Fort Frances was built around a pulp and paper mill at the turn of the century and this plant has historically been the single largest employer supporting the community. In 2009 the plant was owned and operated by Abitibi-Consolidated Inc. at which time the company filed for creditor protection, "Chapter 11." Since then, the operation has been largely curtailed such that currently only 25% of all employees are still employed. Approximately 500 good paying positions have been lost and this has had a significant impact on the local economy. Of these 500 positions, approximately 300 were lost in the spring of 2013.

Although FFPC does not directly supply the manufacturing portions of the Pulp and Paper Mill (as it is transmission connected to HONI), FFPC does supply auxiliary support complexes including office buildings, parking lots, and warehouses. According to the billing history of the auxiliary support complexes, FFPC estimates that the continued curtailment of these facilities will equate to a direct loss of approximately 1.85% of FFPC's total customer load, based on 2012 consumption data. FFPC also anticipates that the mill's production curtailment and labour force layoffs will result in a drop in residential and commercial business load. FFPC estimates that the short term impact will be roughly three times the amount of load lost from servicing the auxiliary support complexes. In the event of prolonged production curtailments and labour force layoffs, FFPC estimates that by 2018 the impact on the community will be roughly five times that of the load lost from servicing the auxiliary support

complexes. There are many variables such as the Canadian Dollar to US Dollar exchange rate, which could have a significant impact on either the success or the demise of the plant, which FFPC cannot predict.

Based on the current state of the plant FFPC anticipates the following reductions:

Reduction Units	2013 Reduction	2014 Reduction	2015 Reduction	2016 Reduction	2017 Reduction	2018 Reduction
Direct Sales to Mill Accounts (kWh)	767,849	1,535,699	1,535,699	1,535,699	1,535,699	1,535,699
Impact on Dependant Consumers (kWh)	2,303,548	4,607,096	5,374,945	6,142,795	6,910,644	7,678,493
Total Reduction as seen at Supply Point (x1.0406)	3,196,096	6,392,192	7,191,216	7,990,240	8,789,264	9,588,288

5.4.3.18 Planned Network (REG) Investments

FFPC has developed a renewable generation enabling improvement plan aimed at safely and reliably accommodating the connection of renewable energy generation facilities. All of FFPC's planned expenditures are for improvements to its transformer station "FFMTS", as the station and its core components are of original 1970's vintage. The station presently cannot accommodate 2-way or reverse electrical flow at any level, as it was designed for the purpose of solely supplying loads.

FFPC's plan is to modify station protection (relaying) and controls over a seven year period, beginning with feeder breakers where it is most likely that a reverse power flow state will be encountered in the near future. FFPC will also be able to improve monitoring of its feeders to establish more accurate and less conservative operating constraints with confidence. Given the current level of interest in renewable generation, FFPC's rationale is to replace relaying and to enhance monitoring in the following sequence over a seven year horizon (years 2012 and 2013 phases have been completed):

1. Tx Station Feeder Breakers
2. Tx Station Transformers and associated Main Secondary Breakers
3. Tx Station Communication Network
4. Tx Station Primary Protection (115 kV Oil Filled Circuit Breakers)
5. Tx Station Supervisory Control & Remote Annunciation

It should be noted that these renewable generation enabling investments also accomplish many mandated Smart Grid objectives, as will be discussed further in this submission.

FFPC's plan is based on the eligible renewable generation enabling improvements as per Section 3.3.2 of the Distribution System Code which limits the scope to:

3.3.2 Renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities are limited to the following:

a. modifications to, or the addition of, electrical protection equipment;
b. modifications to, or the addition of, voltage regulating transformer controls or station controls;
c. the provision of protection against islanding (transfer trip or equivalent);
d. bidirectional reclosers;
e. tap-changer controls or relays;
f. replacing breaker protection relays;
g. Supervisory Control and Data Acquisition system design, construction and connection;
h. any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows; and
i. communication systems to facilitate the connection of renewable energy generation facilities.

The following table summarizes the planned project phases by year:

FFPC Planned Renewable Generation Enabling Improvement Project Summary For Years 2012 to 2018			
Planned Year	**Project Name**	**Estimated Cost**	**OEB Investment Category**
2012	T1 Breakers Protection	$ 27,673	System Access
2013	T2 Breakers Protection	$ 35,000	System Access
2014	Transformer T1 Protection	$ 25,000	System Access
2014	Transformer T2 Protection	$ 25,000	System Access
2015	Tx Station Communication Network Installation	$ 20,000	System Access
2015	Tx Station Data Acquisition System	$ 20,000	System Access
2016	Tx Station OCB Protection	$ 20,000	System Access
2017	Tx Station Supervisory Control	$ 45,000	System Access
2018	Tx Station DC System Monitoring & Remote Annunciation	$ 12,000	System Access
	Total	**$ 229,673**	

5.4.3.18.a. 2012 - T1 Breaker Protection (Installed)

The majority of FFPC's applicant requests for renewable energy connections to date have been for connections to FFPC's "West Feeder (A)," which is supplied from FFPC's station transformer "T1". The West Feeder is the most likely feeder to encounter a reverse power flow state given the volume of existing and proposed generation connections. FFPC has the ability to accommodate considerable renewable generation; however, protection and relaying modifications are required to accommodate the continued demand for connection requests safely and reliably. FFPC placed the highest priority on

replacing the breaker protection (relays) associated with transformer “T1”. In 2012 FFPC replaced the original 1970’s vintage single function electromechanical feeder level breaker relays with modern day Schweizer Engineering Laboratories SEL-751 digital feeder protection relays. The modern day relays provide bi-directional recloser functionality, over-current protection, feeder metering, as well as event/data logging. One device replaces seven individual devices while also delivering additional functionality and flexibility. Given the greatly enhanced functionality, FFPC will be capable of more closely monitoring and logging feeder operating conditions once a communications network is installed. Improved monitoring of operating conditions will allow FFPC to better define operating constraints, as well as quantify feeder reliability. The following figures illustrate the before and after of FFPC’s protection replacement to accommodate renewable energy generation facilities on the “West Feeder (A)”.



Figure 4: West Feeder Original Single Function Electromechanical Relays



Figure 5: West Feeder Replacement Multifunction Protection Relay

5.4.3.18.b. 2013 - T2 Breaker Protection

For the same reasons as mentioned above, FFPC is planning to upgrade transformer T2's vintage single function electromechanical feeder level breaker relays with modern day Schweizer Engineering Laboratories SEL-751 digital feeder protection relays. Again the modern day relays provide bi-directional recloser functionality, over-current protection, feeder metering, as well as event/data logging.

5.4.3.18.c. 2014 - Transformer T1 & T2 Protection

The station power transformers "T1" and "T2" as well as their secondary main breakers are currently also protected by 1970's vintage single function electromechanical relays. Both station transformers are equipped with automatic tap changers that compensate for incoming voltage fluctuations. The existing protection scheme is also not designed for bi-directional or reverse power flow, and as such FFPC is planning to upgrade the dated protection. The installation of a single modern day digital protection unit will replace numerous single function relays, as well as numerous analog measurement gauges and allow for reverse power flow situations.

5.4.3.18.d. 2015 - Transformer Station Communication Network Installation

Fort Frances MTS in its current state does not have any type of communication network to allow Intelligent Electronic Devices (IEDs), such as FFPC's recently installed T1 breaker relays, to communicate to a central data server, a supervisory controller or to any other internal or external devices. FFPC is planning to install a communications network that will allow the interconnection of IEDs on a common network. Fort Frances MTS has two separate buildings housing transformer T1 and T2's respective breaker cells, and this project will supply a common communication network to both buildings. The communications network will be instrumental in allowing for IED control, as well as IED data to be collected for planning and analysis purposes.

5.4.3.18.e. 2016 - Transformer Station OCB Protection

Fort Frances MTS has three single-phase 115 kV Oil Filled Circuit breakers as its primary protection on the incoming transmission line. The existing electromechanical single function protective relays for these breakers are also of original 1970's vintage and also do not accommodate reverse power flows. The existing protection also does not allow for effective monitoring of supply point conditions and lacks the capability of capturing and logging event or operating data.

5.4.3.18.f. 2017 - Transformer Station Supervisory Control

Fort Frances MTS currently does not have any kind of supervisory or SCADA system functionality. FFPC is planning to implement a supervisory system to improve core station functionality. This includes real-time station equipment outage/trouble reporting, as well as automatic operation of station/feeder components. Automatic operation of station/feeder components would allow for the isolation of faults and rerouting of distribution supply, thereby minimizing the effects of localized outages.

FFPC plans to accomplish this by installing and configuring an SEL RTAC SEL-3530 Real-Time Automation Controller, or equivalent. This device will be also be the main device to enable the implementation of the "Smart Grid".

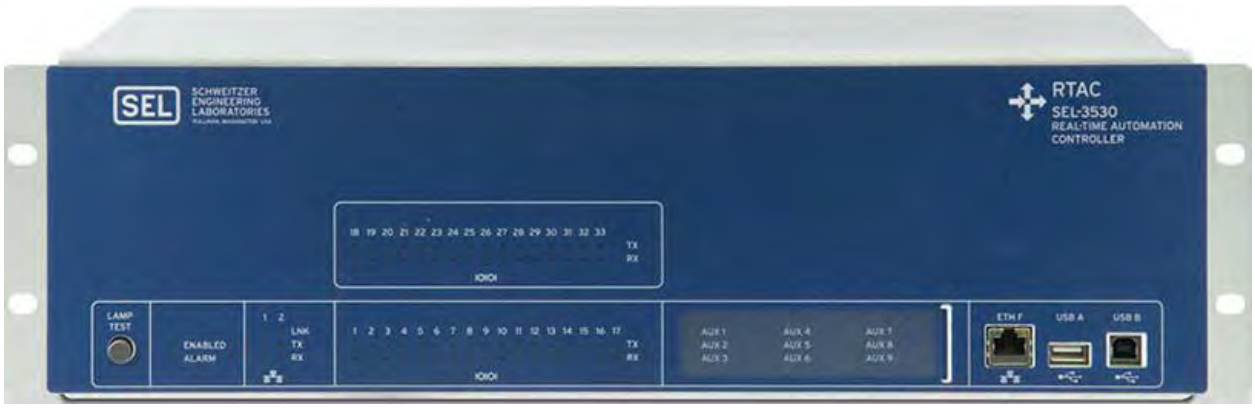
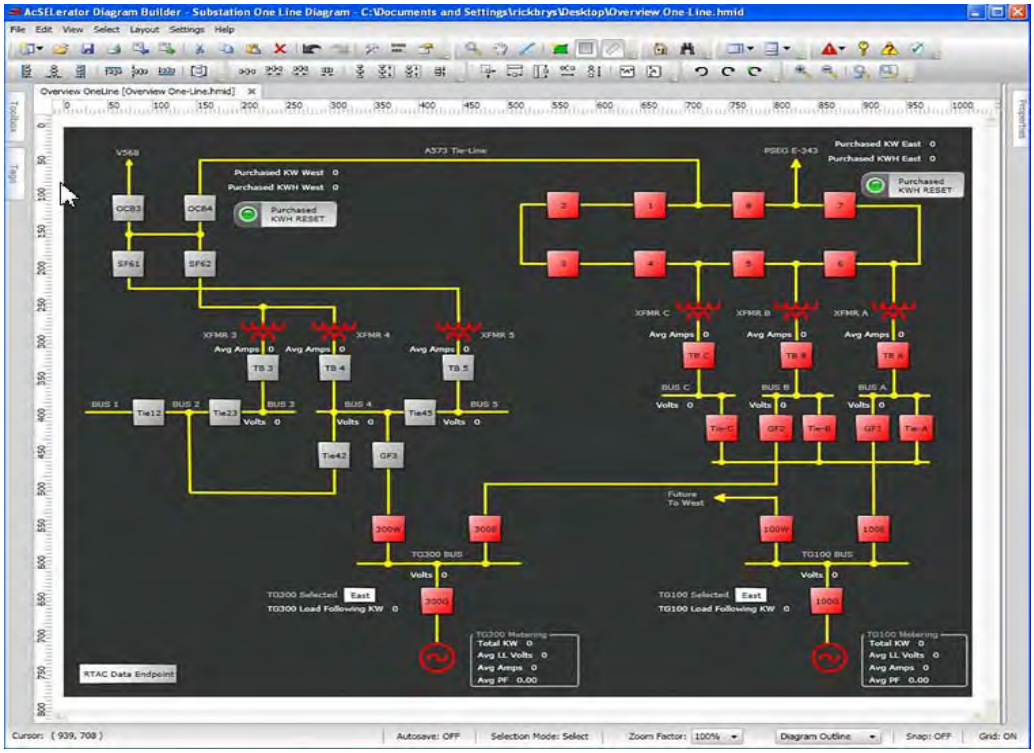


Figure 6 - Schweitzer Engineering SEL-3530 Real-Time Automation Controller

This device will:

- Connect all station IED's together, enabling local/remote device control through a Human Machine Interface (HMI)
- Provide standard data management
- Perform logic functions for system automation
- Provide remote access, with security to FFPC and authorized regional stakeholders
- Provide single point engineering access to connected IED's

The following control schematic is a sample control application using this device, which is essentially what FFPC is planning to deploy.



5.4.3.18.g. 2018 - Transformer Station DC System Monitoring & Remote Annunciation

The controls of Fort Frances MTS DC Systems are also of 1970's vintage and do not offer modern day remote alarming or annunciation of component failures. The loss of DC supply inhibits the ability of station protection to operate normally. For example, FFPC would lose all recloser functionality on its feeders under this scenario. FFPC is planning to implement remote monitoring and alarming on its DC protection systems to ensure that any component failures are brought to FFPC's attention immediately. This functionality will improve the safety and reliability of the transformer station and distribution system as a whole.

5.4.3.18.h. Cost Optimization

FFPC has retained third-party expert advice from Siemen's Canada to assist FFPC in identifying, prioritizing and quantifying necessary renewable generation enabling improvements to accommodate the connection of renewable energy generation facilities. FFPC plans to smooth out expenditures over a seven year horizon for rate stability purposes and as such, annual planned expenditures are at or below FFPC's annual capital investment materiality threshold of $50,000. FFPC believes that this approach aligns with the OEB's objective to "pacing and prioritization of capital investments to promote predictability in rates and affordability for customer."

The installation of transformer station protection equipment requires the expertise of third-party service providers, as this expertise is not available in the Fort Frances area. FFPC has to rely on external

service providers to commute to Fort Frances to perform this type of specialized work. FFPC has taken measures to minimize the overall cost of these planned expenditures by coordinating the installation of renewable generation enabling improvements following regularly scheduled annual maintenance work that is also outsourced to the same external service provider. This will reduce duplication of travelling, mobilization and demobilization costs. Without this synergy FFPC's installation expenses would be approximately 20% higher.

5.4.3.19 Investments Involving Smart Grid

FFPC currently does not have any planned investments specific to only achieving Smart Grid objectives; however, other planned investments such as the previously discussed Renewable Generation Enabling Improvements achieve many of Smart Grid objectives as per the Minister's Directive and subsequent OEB Supplemental Report on Smart Grid.

The concept of what a Smart Grid is and what functionality it entails, is dependent on its application and is therefore specific to every distributor. In the case of FFPC, a Smart Grid should be tailored to FFPC's relatively small service territory located in the harsh climate of the Canadian Shield. Design criteria should be based on system characteristics including distribution feeder dimensions and topography, as well as consideration of transformer station functionality.

Due to the fact that FFPC's distribution feeders are relatively short and that FFPC currently does have any large scale generators connected to them, there is no immediate need for the addition of automated feeder switches or enhanced functionality outside of the "FFMTS" transformer station.

FFPC's definition of a smart grid within the Fort Frances MTS Transformer station includes:

- Fully automated system to maintain power flow under all possible circumstances (under automated supervisory control)
- Automatic annunciation of problems, feeder trips etc., to FFPC personnel
- Remote operation and monitoring of all devices within the transformer station by FFPC or other authorized regional stakeholders
- Local and remote real time metering and logging of data for station mains and feeders
- Data acquisition and storage of basic metering functions for historical trending
- Fault data storage for trending and analysis

FFPC can facilitate all of this functionality by deploying the seven phases of investments as per the previously discussed Renewable Generation Enabling Investments.

According to this plan in 2017 FFPC will be installing the SEL RTAC SEL-3530 Real-Time Automation Controller, or equivalent, which will be the main device to enable the implementation of the "Smart Grid".

This device will:

- Connect all station IED's together, enabling local/remote device control through a Human Machine Interface (HMI)
- Provide standard data management
- Perform logic functions for system automation
- Provide remote access, with security to FFPC and authorized regional stakeholders
- Provide single point engineering access to connected IED's

5.4.3.20 Demonstration Projects

At this time FFPC does not have any planned expenditures towards grid demonstration projects, smart grid studies and planning studies or smart grid employee education and training.

5.4.3.21 Consultations with Regionally Interconnected Distributors and Transmitters

FFPC does not have any regionally interconnected distributors (host or embedded) and is transmission connected to Hydro One Network Inc (HONI). FFPC has been and will continue to consult with Hydro One Networks Inc (HONI) regarding distribution system planning efforts.

Prior to the revised Chapter 5 Consolidated Distribution System Plan Filing Requirements coming into effect, FFPC was providing HONI with annual submissions regarding planned transformer station power outages, load forecasts, and renewable generation connection information. FFPC has been working closely with HONI to coordinate planning efforts to minimize customer interruptions.

FFPC is also copied on all relevant planning notices that the Town of Fort Frances Municipal Planning Office receives. This gives FFPC the opportunity to coordinate planning at the municipality level. For example, FFPC is notified of all new construction requests, which gives FFPC the opportunity to advise the applicants of all service connection related requirements, as well as passing on any other relevant information such as CDM opportunities (New Home Construction Initiative). FFPC has also been involved with the development of the municipal Strategic and Sustainability Plan developments.

FFPC has also worked very closely with other Northern LDC's (The Northwest Group) including Thunder Bay Hydro, Kenora Hydro, Sioux Lookout Hydro and Atikokan Hydro, to deploy common systems and tools where practically possible. For example, the Northwest group deployed a common Elster Energy Axis Smart Metering system. The common solution allows for standardization of hardware, software, security aspects, the sharing of resources and the exchange of data on a common platform.

Refer to section 5.2.2 for discussion regarding Coordinated Planning with Third Parties, as well as Regional Planning Efforts.

5.4.4 Capital expenditure summary

5.4.4.1 FFPC 2014 to 2018 Detailed Capital Project Summary

FFPC has developed a detailed five year capital investment plan based on the outputs of its asset management and capital planning processes. The following tables summarize all capital activities planned over the 2014 to 2018 planning horizon, based on investment need driver information available at the time of preparing this DS Plan. FFPC acknowledges that the investment plan may be subject to considerable change due to unforeseen circumstances.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	General Plant	14-14-007	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		14-14-007	Building Heater Replacements	$3,000	Transformer Station heater replacements	1808	Non-System Physical Plant	G5 - Station Buildings
		14-14-007	Cable Reel Stands	$2,000	Install cable reel stands at Operations Centre	1908	System Cap / Maint Support	G3 - Administrative Buildings
		14-14-007	Replace Shelving	$2,000	Upgrade stores area shelving at Operations Centre	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Meter Room Flooring	$2,500	Misc. meter room improvements - replace flooring and fixtures	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Office A/C	$1,000	Install air conditioning in lunch room	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Admin Area Renovation	$3,500	Misc. Main Office renovations - Reception area	1908	Non-System Physical Plant	G3 - Administrative Buildings
		14-14-007	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		14-14-007	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		14-14-007	Operations Centre Copier	$4,000	Replace Operations Centre end-of-life multimedia centre	1920	Non-System Physical Plant	G1 - Office Equipment
		14-14-007	Computer Hardware	$5,000	Director laptop computers to support real-time communication and paperless information distribution.	1920	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	AMI MAS Server Replacement	$4,000	Replace end-of-life AMI system Master Application Server.	1920	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	AutoCad License	$2,000	Upgrade AutoCad drafting software for technical blue print management	1611	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	MS Office Productivity Package	$2,000	Director MS office productivity package to support real-time communication and paperless information distribution.	1611	Non-System Physical Plant	G6 - Computer Equipment
		14-14-007	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
		14-14-007	Label Printer - Asset Labeling	$2,500	Asset labeler for asset identification initiative (GIS).	1940	Business Operation Eff	G7 - Equipment
		14-14-007	Transformer Safe Transport Kit	$3,000	Transformer safe transport kit to mitigate risk of environmental spill from handling increased volume of failing transformers.	1940	Obj - Safety	G7 - Equipment
		14-18-005	Replace 1978 Fort Garry Industries Cable Reel Trailer	$50,000	Replace end-of-life cable stringing and tensioning trailer.	1930	Non-System Physical Plant	G2 - Vehicles
Total				$96,500				
2014	System Access	14-14-006	LTLT Elimination Pole Lines (88 Pri Spans)	$294,681	Overhead distribution feeder pole line expansions to connect to LTLT customers	1830	Mandated Service Obligations	1 - Fully Dressed Wood Poles
		14-14-006	LTLT Elimination Conductor	$9,180	Primary conductor for LTLT pole line extensions	1835	Mandated Service Obligations	8 - OH Conductors
		14-14-006	LTLT Elimination Directional Bore & Conduit	$27,000	Directional bore underneath CNR right-of-way and install conduit for feeder expansion to connect to LTLT customer.	1840	Mandated Service Obligations	40 - Ducts
		14-14-006	LTLT Elimination Pri UG Conductor	$2,298	Install UG primary conductor in duct (across CNR right-of-way), to extend feeder to connect to LTLT customer.	1845	Mandated Service Obligations	29 - Primary TR XLPE Cables in Duct
		14-14-006	LTLT Elimination Transformers	$38,580	Install new transformer to supply LTLT customers from expanded feeders	1850	Mandated Service Obligations	9 - OH Transformers
		14-18-004	Transformer T1 Protection	$25,000	REG Investment - Transformer Station power transformer T1 control and relaying upgrade.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
		14-18-004	Transformer T2 Protection	$25,000	REG Investment - Transformer Station power transformer T2 control and relaying upgrade.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
Total				$421,739				
2014	System Renewal	14-14-007	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		14-14-007	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct

								Buried
		14-14-007	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		14-14-007	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life CT & PT metering settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		14-14-007	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
		14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$11,036	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	3 Phase Pad Mounted Tx	$25,106	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$47,546	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$11,960	Replace end-of-life critical spare transformers	1850	EOL - Failure	9 - OH Transformers
		14-18-003	Non-Profit Housing - 400 Blk Sixth St W - S118A To AT15	$4,642	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Sixth St Non-Profit Housing	$1,598	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Rainy Crest	$10,010	Replace end-of-life primary underground cables to nursing home.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
Total				$253,576				
2014	System Service	14-14-007	Primary Insulator Replacements	$10,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		14-14-007	Air Break Switches Insulator Replacements	$4,500	Air break switch primary insulator replacements as per inspection findings	1835	Obj - Reliability	4 - OH Line Switch
		14-14-007	Robert Moore Air Break Switch Relocation	$28,000	Remove, replace and relocate air break switch from School Yard	1835	Obj - Safety	4 - OH Line Switch
		14-14-007	Mobile Work Tablets	$2,500	Purchase mobile work tablets for transition to electronic inspection forms and for line crew on-site access to technical documentation.	1920	Other Performance/Functionality	G6 - Computer Equipment
		14-14-007	Elster Tx Primary Data Logger and Meter	$3,500	Primary meter for transformer setting, to support identification of theft of power and transformer loading profile development.	1945	Obj - Safety	G7 - Equipment
Total				$48,500				
2014 Total Capital Budget				**$820,316**				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2015	General Plant	14-18-005	Replace 1999 Ford Pickup	$38,000	Replace end-of-life crew service/support vehicle.	1930	Non-System Physical Plant	G2 - Vehicles
		15-15-009	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		15-15-009	Build Outdoor Transformer Shelter	$6,000	Install weather shelter for transformer yard storage area.	1908	System Cap / Maint Support	G3 - Administrative Buildings
		15-15-009	Replace Shop Rollup Door	$12,000	Replace operations centre rollup garage door.	1908	System Cap / Maint Support	G3 - Administrative Buildings
		15-15-009	Reg & Finance Area Renovations	$3,500	Misc. Main Office renovations - Finance Area	1908	Non-System Physical Plant	G3 - Administrative Buildings
		15-15-009	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		15-15-009	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		15-15-009	PC Replacement	$5,000	Replace end-of-life computers at the Main Office.	1920	Non-System Physical Plant	G6 - Computer Equipment
		15-15-009	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		15-15-009	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
Total				$75,500				
2015	System Access	14-18-004	Station Data Acquisition System	$20,000	REG Investment - install data acquisition system to connect to station IED's (intelligent electronic devices).	1531	Mandated Service Obligations	43 - Remote SCADA
		14-18-004	Station Communication Network Installation	$20,000	REG Investment - Install local area network at TS to enable connection of IED's and access to operating data.	1531	Mandated Service Obligations	G8 - Communication
Total				$40,000				
2015	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$135,682	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$72,234	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$32,660	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	1557 Colonization Rd W U/G	$8,609	Replace end-of-life primary underground cable servicing residential area	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	UG Feeder Cable Condition Testing & Rejuvenation Pilot	$28,000	Rejuvenate end-of-life primary underground feeder cables - pilot silicone injection technology project.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		15-15-009	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		15-15-009	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried

		15-15-009	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		15-15-009	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		15-15-009	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$418,863				
2015	System Service	15-15-008	Transformer Fire Barrier	$62,000	Install fire and blast barrier between power transformer T1 and T2.	1808	Obj - Reliability	G5 - Station Buildings
		15-15-009	Backup Generator Switch / Install	$4,500	Install transfer switch and panel for connection of emergency backup generation to supply station lighting and DC battery bank chargers.	1808	Obj - Reliability	G5 - Station Buildings
		15-15-009	Generator	$5,500	Transformer Station backup generator for emergency lighting and DC system charging.	1808	Obj - Reliability	G5 - Station Buildings
		15-15-009	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		15-15-009	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		15-15-009	Mass Customer Contact System	$15,000	Install and commission mass customer contact system to enable contacting customers regarding important event such as power interruptions.	1955	Customer Preference	G8 - Communication
		15-16-010	Financial Information System Phase 1	$40,000	Purchase and commission Financial Information System to enable data exports, enhanced reporting and data analysis for planning activities.	1611	Business Operation Eff	G6 - Computer Equipment
Total				$142,000				
2015 Total Capital Budget				**$676,363**				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2016	General Plant	14-18-005	Replace 2003 Ford 4x4 Half Ton	$40,000	Replace end-of-life crew service/support vehicle.	1930	Non-System Physical Plant	G2 - Vehicles
		16-16-012	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		16-16-012	Interior Lighting Retrofit	$3,000	Transformer Station T12 lighting replacements	1808	Business Operation Eff	G5 - Station Buildings
		16-16-012	Yard Landscaping	$3,000	Landscape yard at Operations Centre - Install flower beds and general yard improvements	1908	System Cap / Maint Support	G3 - Administrative Buildings
		16-16-012	Cable Reel Shelter	$6,000	Install shelter over outdoor cable reel storage area	1908	System Cap / Maint Support	G3 - Administrative Buildings
		16-16-012	Office Carpeting	$2,500	Replace Main Office carpets.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		16-16-012	Executive Area Renovations	$3,500	Misc. Main Office renovations - Board Room	1908	Non-System Physical Plant	G3 - Administrative Buildings
		16-16-012	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		16-16-012	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		16-16-012	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		16-16-012	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
		16-16-012	Main Office Telephone Data Logger	$7,000	Purchase and commission Main Office telephone system data logger, to support telephone accessibility related RRR reporting.	1955	Business Operation Eff	G8 - Communication
Total				$76,000				
2016	System Access	14-18-004	Station OCB Protection	$20,000	REG Investment - Upgrade station independent breaker controls and protection.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
Total				$20,000				
2016	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$49,680	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	3 Phase Pad Mounted Tx	$66,319	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$37,031	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$31,050	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	Westfort Apartments	$2,457	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

		14-18-003	Green Manor Apartments	$2,542	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Rose Manor Apartments	$1,574	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		16-16-011	1947 OCB Replacements	$150,000	Replace end-of-life station independent breaker at Transformer Station.	1815	EOL - Failure Risk	17 - Station Independent Breakers
		16-16-012	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		16-16-012	T1 Battery Charger	$22,000	Replace end-of-life battery charger for Transformer Station T1 DC system.	1825	EOL - High Performance Risk	15 - Station DC System
		16-16-012	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		16-16-012	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		16-16-012	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		16-16-012	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$504,331				
2016	System Service	15-16-010	Financial Information System Phase 2	$20,000	Integrate payroll and purchasing into FIS system.	1611	Business Operation Eff	G6 - Computer Equipment
		16-16-012	115 kV Sky Structure Insulator Replacements	$25,000	Replace Transformer Station primary insulators on sky structure.	1815	Obj - Reliability	23 - Steel Structure
		16-16-012	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		16-16-012	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
Total				$60,000				
2016 Total Capital Budget				$660,331				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2017	General Plant	17-17-013	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		17-17-013	Technical Station Renovations	$3,000	Transformer Station technical station renovations	1808	System Cap / Maint Support	G5 - Station Buildings
		17-17-013	Training Room Carpeting	$2,500	Replace carpeting in the training room located at the Operation Centre.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		17-17-013	Door Replacements	$2,000	Operations Centre door replacements.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		17-17-013	Technical Workstation Replacement	$3,500	Misc. Main Office renovations - Technical Office	1908	Non-System Physical Plant	G3 - Administrative Buildings
		17-17-013	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		17-17-013	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		17-17-013	Media Centre (Photo Copier)	$11,000	Replace the Main Office end-of-life media centre.	1920	Non-System Physical Plant	G1 - Office Equipment
		17-17-013	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		17-17-013	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
Total				$33,000				
2017	System Access	14-18-004	Station Supervisory Control	$45,000	REG Investment - Install station controller and commission station supervisory control (monitor operating conditions and perform appropriate control actions currently performed manually).	1531	Mandated Service Obligations	43 - Remote SCADA
Total				$45,000				
2017	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$123,932	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	3 Phase Pad Mounted Tx	$40,213	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$118,209	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pad Mounted Tx Spares	$15,525	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx Spares	$11,500	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	Rainbow Motel	$917	Replace end-of-life primary underground cables to multi-residential business complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Armstrong Apartments	$659	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

		14-18-003	Shevlin Towers West	$1,667	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Shevlin Towers East	$1,672	Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Feeder UG Cable Refurbishment Phase 1	$75,000	Rejuvenate end-of-life primary underground feeder cables. Attempt to sustain cables until Transformer Station as whole is at its end-of-life in 2034, at which time cables become obsolete.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		17-17-013	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		17-17-013	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		17-17-013	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		17-17-013	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		17-17-013	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$530,971				
2017	System Service	17-17-013	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		17-17-013	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		17-17-013	Elster "Access Detect" (OMS)	$43,000	Purchase and commission Outage Management System, to enable proactive outage alerts and localized customer interaction.	1611	Customer Preference	G6 - Computer Equipment
Total				$58,000				
2017 Total Capital Budget				**$666,971**				

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2018	General Plant	14-18-005	Replace Chipper Trailer	$25,000	Replace end-of-life chipper trailer to support vegetation management maintenance program.	1930	Non-System Physical Plant	G2 - Vehicles
		14-18-005	Replace 2004 Altec Double Bucket Truck	$250,000	Replace end-of-life double bucket truck, to support maintenance, capital and operational activities.	1930	System Cap / Maint Support	G2 - Vehicles
		18-18-014	Misc Building Improvements	$2,000	Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
		18-18-014	Bathroom Renovation	$2,000	Transformer Station bathroom renovations	1808	System Cap / Maint Support	G5 - Station Buildings
		18-18-014	Window Replacements	$6,000	Replace Operations Centre windows.	1908	Non-System Physical Plant	G3 - Administrative Buildings
		18-18-014	Main Office Bathroom Renovations	$3,500	Misc. Main Office renovations - Bathroom	1908	Non-System Physical Plant	G3 - Administrative Buildings
		18-18-014	Misc. Main Office furniture replacements	$2,000	Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		18-18-014	Misc. Operations Centre furniture replacements	$1,000	Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
		18-18-014	Computer Hardware	$1,000	Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
		18-18-014	Small Tools	$5,000	Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
		18-18-014	Phone System Upgrade	$13,000	Replace end-of-life Meridian phone system at the Main Office.	1955	Non-System Physical Plant	G8 - Communication
Total				$310,500				
2018	System Access	14-18-004	Station DC System Monitoring & Remote Annunciation	$12,000	REG Investment - Install supervisory control over auxiliary station components including DC systems.	1531	Mandated Service Obligations	43 - Remote SCADA
Total				$12,000				
2018	System Renewal	14-18-001	Primary Poles Replacements	$100,460	Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Secondary Pole Replacements	$24,110	Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
		14-18-001	Unplanned Poles Replacements	$5,358	Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
		14-18-002	1 Phase Pad Mounted Tx	$48,430	Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
		14-18-002	Pole Mounted Tx	$115,053	Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-002	Pole Mounted Tx Spares	$14,375	Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
		14-18-003	Strachan pl. switch S22-B	$9,874	Replace end-of-life primary underground cables in multi-residential area.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	Riverview Cemetery	$5,741	Replace end-of-life primary underground cables to public municipal building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		14-18-003	CIBC	$575	Replace end-of-life primary underground cables to priority business customer.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

		14-18-003	Feeder UG Cable Refurbishment Phase 2	$25,000	Rejuvenate end-of-life primary underground feeder cables. Attempt to sustain cables until Transformer Station as whole is at its end-of-life in 2034, at which time cables become obsolete.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
		18-18-014	DC System Battery Cell Replacement	$2,000	Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
		18-18-014	UG Service Replacement	$2,000	Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
		18-18-014	OH Service Replacement	$2,000	Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
		18-18-014	CT/PT and Cabinet Replacements	$2,500	Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
		18-18-014	Meter Replacements	$3,250	Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
Total				$360,724				
2018	System Service	18-18-014	Primary Insulator Replacements	$5,000	Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
		18-18-014	OH Secondary Bus Replacements	$10,000	Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
Total				$15,000				
2018 Total Capital Budget				**$698,224**				

5.4.4.2 Table 2-AB Capital Expenditure Summary

As per the Section 5.4.4 filing requirements, the following summary table in accordance to "Table 2-Capital Expenditure Summary", and summarizes FFPC's capital expenditures by investment category for the period 2006 through 2018. The original table can be found under the "Exhibit 2 Appendices" worksheet, under Tab "App.2-AB_Capital_Expenditures". "Explanatory notes on variances are not provided as this is FFPC's first DS Plan under the new filing requirements, and as such "Planned to Actual" balances are not available.

CATEGORY	Historical Period (previous plan[1] & actual)														
	2006			2007			2008			2009			2010		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access		-	--		-	--		-	--		-	--		-	--
System Renewal		191	--		130	--		154	--		153	--		166	--
System Service		43	--		43	--		16	--		6	--		80	--
General Plant		100	--		21	--		17	--		118	--		277	--
TOTAL EXPENDITURE	-	335	--	-	194	--	-	187	--	-	278	--	-	523	--
System O&M		$ 248	--		$ 281	--		$ 305	--		$ 325	--		$ 376	--

CATEGORY	Historical Period (previous plan[1] & actual)									Forecast Period (planned)				
	2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		3	--		41	--		37	--	422	40	20	45	12
System Renewal		133	--		165	--		150	--	254	419	504	531	361
System Service		1	--		-	--		55	--	49	142	60	58	15
General Plant		9	--		16	--		157	--	97	76	76	33	311
TOTAL EXPENDITURE	-	145	--	-	222	--	-	399	--	820	676	660	667	698
System O&M		$ 365	--		$ 591	--		$ 423	--	$ 675	$ 722	$ 777	$ 839	$ 894

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

5.4.5 Justifying Capital Expenditures

With the recent development and implementation of formalized asset management and capital planning processes, FFPC has taken a new approach to identifying, prioritizing and categorizing system renewal projects driven by assets reaching the end of their useful service life. FFPC also subjects its General Plant assets to these processes, to determine which assets require replacement or refurbishments, just like distribution system assets. In the past, distribution system renewal projects were typically performed on a Region or Zone Basis, such as "Scott Street Pole Replacements"; however, with availability of intricate asset specific dimensional and condition data, FFPC has transitioned to an asset class investment approach based on the results of the asset management and capital planning processes. Using this approach, FFPC limits replacements to the "worst in class" assets and does not replace assets that are in the same "zone" which may still have significant useful life remaining.

For example; FFPC now has an annual capital project (class) entitled "Primary Underground Cable Replacements", which is based on the itemized primary cable runs contained within FFPC's GIS system. For 2014, FFPC's asset management process identified that the primary cable runs "Rainy Crest Nursing Home", "Sixth Street Non-profit Housing Complex A and B" have a high risk of failure and that the impact of failure is high, as all three cable runs supply large housing complexes. Based on GIS dimensional data and asset specific costing tables, FFPC has established a budgeted replacement cost of $16,250.56. The budget amount is based on:

Rainy Crest Nursing Home - 87.12 Meters of 3 Phase UG Service @ $114.90 / Meter = $10,010

Sixth St. Non-Profit Housing A - 34.77 Meters 1 Phase UG Service @ $45.96 / Meter = $1,598

Sixth St. Non-Profit Housing B - 101.01 Meters 1 Phase UG Service @ $45.96 / Meter = $4,642

Total 2014 Budget for "Primary UG Cable Replacements" = $16,250

Cost data is based on the actual average cost of underground cable replacements performed in recent history.

FFPC has taken this approach for all significant asset classes that are populated in the GIS system including: Fully Dressed Wood Poles; OH Line Switches; OH Conductors; OH Transformers; Primary TR XLPE Cables in Duct; Secondary Cables Direct Buried; Single Phase Pad-Mounted Transformers; Three Phase Pad-Mounted Transformers; Trucks & Buckets; Smart Meters; Data Collectors; and Wholesale Energy Meters.

Transformer station assets are made up of a relatively small number of high cost assets such as Power Transformers and Station Metal Clad Switchgear. System renewal investments are typically "lumpy", as they are very periodic in nature and not conducive to being spread over longer periods of time. FFPC has also grouped system renewal transformer station related capital projects by asset class.

5.4.5.1 Overall plan

FFPC developed this DS Plan with a focus on achieving the performance outcomes established for electricity distributors under the Renewed Regulatory Framework for Electricity, in regards to Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.

5.4.5.1.a. Customer Focus:

FFPC is dedicated to providing services in a manner that responds to customer preferences. During the summer of 2013, FFPC conducted an extensive customer satisfaction survey, which was instrumental in gauging satisfaction, identifying improvement opportunities and assessing future customer needs. The feedback gathered has helped to shape our capital expenditures and to devote operational resources over the planning period, to align service offerings with the needs of our customer base. Customer clearly identified that they:

1. Are overall very satisfied with the reliability of electricity supplied and with the services provided by FFPC.
2. Feel the most important electricity-related issue facing them is the overall cost of electricity.
3. Would like FFPC to have the ability of contacting them directly, regarding important events such as power interruptions.
4. Would like FFPC to transition to true calendar based monthly billing.
5. Would like a choice of receiving paper of electronic bills.
6. Would like access to monthly billing information.
7. Are very interested in learning more about how they can conserve electricity.

In response to the needs and requests identified, FFPC will be transitioning to true monthly billing, offering a choice of electronic or paper billing, as well as granting access to consumption and billing data in 2014. FFPC also plans to invest in a mass customer contact system, as well as in an outage management system. These investments will enable FFPC to improve its ability to manage outages, as well as improve FFPC's ability to communicate directly with customers regarding important events such as outages. With the help of this technology, customer communication will be conducted in an efficient and effective manner. A new "Technical Customer Services Representative" position is also planned to be included in FFPC's organizational structure, to focus on continued customer and stakeholder engagement activities, as well as to support the annual execution of newly developed asset management and capital planning processes. FFPC also plans to utilize the position to conduct customer education campaigns in local schools, at tradeshows, town hall meetings as well as through standard media outlets. As a result of FFPC's customer engagement activities, $58,000 has been dedicated towards capital expenditures to address customer needs, which represents 1.6% of all planned capital expenditures over the 2014 to 2018 planning period. In addition to this, FFPC will be devoting significant staff resources towards the implementation of the above mentioned projects.

5.4.5.1.b. Operational Effectiveness

FFPC has a long history of utilizing technology and employee innovation to improve on its operational efficiency and effectiveness. The newly developed asset management and capital planning processes, which have been built on the foundation of a first class GIS system, are instrumental in enabling FFPC to realize sustainable long term saving through improved asset lifecycle management, long term planning capabilities and data driven decision making. Over the 2014 to 2018 planning horizon, FFPC estimates that it will realize $455,757 is cost savings through its improved asset oversight, enabling good planning. The savings are expected to be achieved without negatively impacting system reliability or quality related objectives. Of the $3,522,205 in total planned capital expenditures, $2,775,966 or 78.8 %, are related to managing the lifecycle of assets. This underscores the importance and value of the newly developed GIS based asset management and capital planning processes. FFPC is also planning to invest an additional $72,500, towards achieving more effective financial oversight of its operation, through the deployment of a Financial Information System. The additional business operational efficiency investments represent 2.1% of the total planned capital expenditures. FFPC believes that its strategy and this DS Plan will deliver value for money, to all of FFPC's customers.

5.4.5.1.c. Public Policy Responsiveness

FFPC is committed to delivering on its mandated service obligations. At the time of preparing this DS Plan, the following mandated service obligations significantly impacted the plan: the Elimination of Long Term Load Transfers by June 30th, 2014; to support the Connection of Renewable Generation; to facilitate the implementation of a Smart Grid; and to achieve the mandated CDM Targets through the delivery of CDM Programs.

FFPC has dedicated $371,739 towards the mandated elimination of Long Term Load Transfer arrangements through expansion of its distribution feeders. The expansions will resolve the long standing issue and will actually improve FFPC's ability to accommodate large scale Renewable Generation Facilities, unlock access to approximately 25% of FFPC's undeveloped distribution service territory, promote the overall economic well being of the community by encouraging growth, as well as enable the benefits of the 1905 Historic Power Agreement to be distributed to the LTLT customers.

Over the last few years, FFPC conducted a system wide analysis to assess the capability of connecting renewable generation onto its distribution feeders, as well as directly to its greater than 50 kV transformer station. Practical constraints were identified that greatly limit the overall generation capacity that FFPC's distribution system can accommodate. FFPC has developed a seven year plan towards the implementation of Renewable Enabling Improvements, that will increase the potential renewable generation capacity from 1.3 MW to 10.8 MW. All renewable enabling improvements are towards controls and protections upgrade at FFPC's greater than 50 kV transformer station "Fort Frances MTS". The station upgrades will also allow for individual feeder performance monitoring, from which operating constraints are set. Constraints are currently set to error on the side of caution as no feeder monitoring is in place. The OPA has confirmed that FFPC's plan is aligned with regional needs developments. FFPC has planned $229,673 in renewable enabling improvements, of which $167,000

(4.7% of total capital expenditures) is planned over the 2014 to 2018 planning period. FFPC has previously incurred $62,673 throughout 2012 and 2013 in renewable enabling improvement expenditures, for which it will also be seeking recovery.

FFPC currently does not have any planned investments specific to only achieving Smart Grid objectives; however, other planned investments such as the Renewable Generation Enabling Improvements achieve many of Smart Grid objectives. The proposed transformer station improvements will support Smart Grid objectives under the Power System Flexibility, Customer Control and Adaptive Infrastructure categories. The improvements will also allow for the sharing of information with regional stakeholders.

5.4.5.1.d. Financial Performance

FFPC operates under a rate minimization philosophy with the objective of balancing investment needs, with providing customers with a safe and reliable supply of electricity at the lowest possible rates. FFPC has taken a "just-in-time" asset replacement approach, under which assets will be replaced on a proactive manner as they approach their high probability of failure zone in their lifecycle, as established by FFPC's asset management and capital planning processes. FFPC's strategy is to pace investments according to the rate at which its asset base is deteriorating, so as to maintain long term perpetual viability. This ensures that the asset base as a whole is not driven to failure (end-of-life), at which time enormous reinvestment would be required. The DS Plan has been built on this premise, and as such the investments contained within it are essential to maintain FFPC's long term viability. FFPC's asset management and capital planning processes are instrumental in ensuring that savings from operational effectiveness are sustainable. FFPC has a good track record of wise spending, and has kept its cost base to a bare minimum in the interest of ratepayers. Over the period 2006 to 2012 (2005 is base year), the average annual percentage OM&A increase of the electrical distribution industry in Ontario that was required to meet changing business demands was 29.7% (based on OEB Yearbooks). Over this period, FFPC's average annual percentage OM&A increase was 21.9%. If FFPC would have kept pace with OM&A expenditures relative to the demands of industry, FFPC's customer would have incurred $581,303 in additional expense. The savings are largely attributed to FFPC's approach of adjusting its business needs on a reactive basis, upon the numerous industry changes that occurred between 2005 and 2012 reaching their "steady state". FFPC credits its staff and service providers for enduring significantly intensified short term workloads, which were necessary to implement the multitude of sector changes. The current level of effort exerted by FFPC's staff is not sustainable, and as such FFPC is realigning its revenue requirement to fund additional resources (the addition of a Technical Customer Service Representative to staff, as well as more necessary services from third party service providers including Human Resources, Legal and IT expertise). To help offset funding additional resources, FFPC is projecting to realize $455,757 in sustainable cost savings over the 2014 to 2018 planning period, without negatively impacting the reliability or efficiency of its distribution system. The savings are attributed to the implementation of the newly developed asset management and capital planning processes. The processes have given FFPC improved oversight of its entire asset base managed, at the individual asset level, thereby enabling precise data driven decision making and long range planning. Improved decision making will result in optimizing investment needs to support the right investments at the right time.

5.4.5.1.e. FFPC 2014 to 2018 Capital Project Summary

FFPC has devised a new numbering and grouping system for its capital projects, to reflect the multiyear nature of many material projects. The naming convention is "XX-YY-ZZZ" where "XX" denotes the last two digits of the project start year, "YY" denotes that last two digits of the project end year, and "ZZZ" denotes the sequential progression of unique projects, beginning at 001. Each project number is referred to as a "Parent ID", under which various logical activities may occur. The activities are broken down by the asset class into which expenditures are recorded under. All unique capital projects that exceed FFPC's materiality threshold of $50K are assigned a "Parent ID", and small capital projects that do not exceed the materiality threshold are grouped into a "Miscellaneous Small Capital Projects" by year, which is also assigned a "Parent ID".

5.4.5.2 Material Investments

FFPC's materiality threshold for is $50,000.

5.4.5.2.a. Capital Project Summary by Parent ID

The following table summarizes all planned capital expenditures by Project Parent ID:

Project Parent ID	Capital Project Name	2014	2015	2016	2017	2018	2014 - 2018 Total
14-18-001	Fully Dressed Wood Pole Replacement Program	$129,928	$129,928	$129,928	$129,928	$129,928	$649,638
14-18-002	Overhead & Pad-Mounted Transformer Replacement Program	$95,648	$240,576	$184,080	$309,379	$177,858	$1,007,541
14-18-003	Primary UG Cable Replacement and Rejuvenation Program	$16,251	$36,609	$6,573	$79,915	$41,189	$180,537
14-18-004	Over 50 kV Transformer Station - Renewable Enabling Improvements	$50,000	$40,000	$20,000	$45,000	$12,000	$167,000
14-18-005	Fleet Vehicle Replacement Program	$50,000	$38,000	$40,000	$0	$275,000	$403,000
14-14-006	Elimination of Long Term Load Transfers	$371,739	$0	$0	$0	$0	$371,739
14-14-007	2014 Misc. Small Capital Project	$106,750	$0	$0	$0	$0	$106,750
15-15-008	Transformer Station - Power Transformer Fire Barrier	$0	$62,000	$0	$0	$0	$62,000
15-15-009	2015 Misc. Small Capital Project	$0	$89,250	$0	$0	$0	$89,250
15-16-010	Financial Information System Integration	$0	$40,000	$20,000	$0	$0	$60,000
16-16-011	Transformer Station - Independent Breaker Replacement	$0	$0	$150,000	$0	$0	$150,000
16-16-012	2016 Misc. Small Capital Project	$0	$0	$109,750	$0	$0	$109,750
17-17-013	2017 Misc. Small Capital Project	$0	$0	$0	$102,750	$0	$102,750
18-18-014	2018 Misc. Small Capital Project	$0	$0	$0	$0	$62,250	$62,250
Total	**Total Projected Annual Capital Budget**	**$820,316**	**$676,363**	**$660,331**	**$666,971**	**$698,224**	**$3,522,205**

5.4.5.2.a.i. 14-18-001 (System Renewal): Fully Dressed Wood Poles Replacement Program

Investment Category: System Renewal		**Project Start Date:** Jan.1, 2014
Project Title: Fully Dressed Wood Poles Replacement Program		**Project End Date:** Dec. 31, 2018
Asset Category(s): Fully Dressed Wood Pole		**Project Driver(s)**: End-of-Life, Risk of Failure & Failure
USoA Account: 1830 - Poles, Tower & Fixtures	**Tot. 2014-2018 Cap. Cost:** $649,638 **Tot. 2014-2018 O&M Cost:** $0	**Ave Annual Cap. Cost:** $129,928

A. General information on the Project/Activity

FFPC's asset management process annually identifies wood poles that are at the end of their useful service life based on an age, inspection and condition testing analysis. The process targets individual poles that have a high risk of failure as opposed to conventional approaches that target all poles within a region or zone, such as a block or street. FFPC's asset management process has identified, and will continue to identify, poles that are reaching or have reached the end of their useful service life over the 2014 to 2018 planning horizon. The pace at which wood poles reach their end of useful service life is a function of their deterioration based largely on age and operating conditions that they are subjected to. FFPC will annually select the worst thirty (30) primary poles and twelve (12) secondary poles that are most likely to fail due to deterioration. One additional primary pole and secondary pole replacement have also been allocated annually, for unplanned circumstances which may arise due to sudden failures caused by external influences such as motor vehicles, (snow ploughs / tractor trailer hit and runs) or pole fires. Deteriorated wood poles pose a serious threat to customer and employee safety, as well as they undermine distribution system reliability and structural integrity. The planned number of replacements is closely aligned with the optimum annual replacement rate of 40 poles per year, which assumes an evenly distributed population based on a Typical Useful Service Life of forty-five (45) years. Over the last five years, FFPC's annual pole condition testing identified an average of 42.4 poles per year that were deemed to have reached or exceeded the end of their useful service life. Premature failures have also occurred frequently over the course of history due to manufacturing flaws in the wood treatment process. As such, FFPC is experiencing slightly higher than anticipated levels of condition test failures. Poles that are being installed on a go forward basis are expected to last forty-five years. This investment is viewed as a core business reinvestment and as such is treated as non-discretionary. The following table summarizes the planned activities, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	System Renewal	14-18-001	Primary Poles Replacements	$100,460		Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2014	System Renewal	14-18-001	Secondary Pole Replacements	$24,110		Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2014	System Renewal	14-18-001	Unplanned Poles Replacements	$5,358		Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
2015	System Renewal	14-18-001	Primary Poles Replacements	$100,460		Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2015	System Renewal	14-18-001	Secondary Pole Replacements	$24,110		Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2015	System Renewal	14-18-001	Unplanned Poles Replacements	$5,358		Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
2016	System Renewal	14-18-001	Primary Poles Replacements	$100,460		Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2016	System Renewal	14-18-001	Secondary Pole Replacements	$24,110		Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2016	System Renewal	14-18-001	Unplanned Poles Replacements	$5,358		Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
2017	System Renewal	14-18-001	Primary Poles Replacements	$100,460		Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2017	System Renewal	14-18-001	Secondary Pole Replacements	$24,110		Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2017	System Renewal	14-18-001	Unplanned Poles Replacements	$5,358		Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles
2018	System Renewal	14-18-001	Primary Poles Replacements	$100,460		Replacement of end-of-life primary poles as determined by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2018	System Renewal	14-18-001	Secondary Pole Replacements	$24,110		Replacement of end-of-life secondary wood poles as identified by asset management process.	1830	EOL - Failure Risk	1 - Fully Dressed Wood Poles
2018	System Renewal	14-18-001	Unplanned Poles Replacements	$5,358		Unplanned pole replacements from sudden failure caused by external influence	1830	EOL - Failure	1 - Fully Dressed Wood Poles

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

FFPC's newly developed asset management process by nature targets individual poles that are most likely to fail (Step 4). As such, poles are not changed simply because they are in a zone that is being rebuilt due to many assets within the zone coming to the end of their useful service life. FFPC is able to travel to any point along its distribution system within a short time frame, which is conducive to selectively targeting replacements. This approach is also very efficient as it targets the weakest links throughout FFPC's entire service territory, thereby strengthening the integrity of the distribution system as a whole. In reality, a system is only as strong as its weakest link. FFPC's strategy is also to replace End-of-Life poles under planned and coordinated conditions, as opposed to under emergency or afterhours conditions, which add unnecessary risk and expense. Capital reinvestments into wood poles are essential to sustain FFPC's ability to safely, efficiently, reliably and cost-effectively distribute electricity to its customers. When wood poles are replaced, pole hardware inspections are performed on major components to assess whether or not they are suitable for reuse. Typically hardware such as metal stand-off brackets are suitable for reuse, as they are expected to outlast two lifecycles of the wood poles to which they are affixed.

2. Safety

This investment will eliminate potential safety hazards to both the general public and FFPC employees. The replacements will also reduce the likelihood of sustaining storm related damage, which often pose safety hazards to the general public and employees.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

FFPC constructs its wood pole framing according to USF Construction Standards, which are commonly used amongst LDC's throughout Ontario. Approximately two-thirds of all distributors construct their plant to USF Standards. When replacing poles, FFPC is also mindful of the future needs of other stakeholders including Third Party Attachers.

5. Economic Development

Essentially all material will be purchased through local or regional suppliers, who utilize many Ontario manufacturers. FFPC's labour force and fleet vehicles will be utilized to complete the replacements. Additional support services as required will be supplied by local service providers, such as vacuum excavation or trenching. This project will benefit both the local and provincial economy.

6. Environmental Benefits

FFPC is committed to conducting its business in an environmentally responsible manner. This project will reduce the overall risk of environmental incidents occurring as a direct result of

wood pole failures. FFPC's reuse of pole line hardware practices also minimize the amount of waste that is generated.

C. Category-specific requirements for each project/activity

System Renewal: FFPC's Fully Dressed Wood Pole replacement project is categorized as System Renewal. Over the course of history FFPC has reinvested into wood pole replacements at a fairly uniform annual rate, and as such, the age profile is relatively evenly distributed. FFPC has adopted the expectation that wood poles will achieve a useful service life of forty-five years as per the TUL values established in the "Kinectrics Report". This is an aggressive target, as wood poles are subjected to the harsh climate of Northern Ontario which accelerates deterioration. As previously mentioned, FFPC has also experienced premature pole failures due to improper manufacturing treatment processes, which have resulted in elevated replacement rates. Catastrophic pole failures have a high probability of impacting a significant number of customers in all classes, as they have the potential of disrupting the service of entire feeder sections. Maintaining the structural integrity of wood poles is also crucial to support public and employee safety, as well as the overall reliability of the distributions system. Wood poles fail when the mechanical stress they are subjected to is greater than their structural integrity, which are often put to the test during events of extreme weather. Failures often occur during storms or under extreme weather conditions such as high winds or snow loads. The probability of suffering storm damage and associated interruptions from high winds are greatly reduced as the weakest links conducive to failure are eliminated.

This investment will therefore support maintaining current distribution system performance levels, ensuring that they will continue to meet or exceed regulatory requirements and customer expectations. Furthermore, this investment will benefit all customers across all rate classes. The quantity and selection summary of pole replacements is based on FFPC's asset management process which revealed the following relative to 2014:

Fully Dressed Wood Poles Profile		Fully Dressed Wood Poles Lifecycle Budget Analysis	
1776	Quantity	41.4	10 Year Historic Replacement/Installation Rate (Units/Year)
45	UL (Adopted)	220	Quantity Reaching Adjusted End of Life Over Forecast Period
21.8	Average Age of Population	$649,638	Total Capital Replacement Cost over Forecast Period
39.47	Ideal Equalized Annual Replacement Rate (Units/Yr)	$30,000	Total Capital Refurbishment Cost over Forecast Period
48.4%	% UL Consumed	44.00	Average Replacements Per Year
59.5%	2019 % UL Consumed with no Reinvestment	$135,928	Average Annual Cost Per Year
		$130,017	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$649,638	2014 - 2018 Total Allocated Capital Replacement Amount
		$30,000	2014 - 2018 Total Allocated Capital Refurbishment Amount

Replacement costs are based on current costs and are not adjusted to reflect inflation. FFPC's estimated replacement cost is $3,348 for primary poles and $2,009 for secondary poles. FFPC has budgeted the following over the forecast period:

Budget Year	Primary Poles	Secondary Poles	Unplanned Quantity	Annual Replacement Cost
2014	30	12	2	$ 129,928
2015	30	12	2	$ 129,928
2016	30	12	2	$ 129,928
2017	30	12	2	$ 129,928
2018	30	12	2	$ 129,928

5.4.5.2.a.ii. 14-18-002 (System Renewal): Overhead & Pad-Mounted Transformer Replacement Program

Investment Category: System Renewal		**Project Start Date:** Jan.1, 2014
Project Title: Overhead & Pad-Mounted Transformer Replacement Program		**Project End Date:** Dec. 31, 2018
Asset Category(s): OH & UG Transformers		**Project Driver(s)**: End-of-Life
USoA Account: 1850 - Line Transformers	**Tot. 2014 - 2018 Cap. Cost:** $1,007,541 **Tot. 2014 - 2018 O&MA Costs:** $0	**Ave Annual Cap. Cost:** $201,508.20

A. General information on the Project/Activity

FFPC's asset management process has identified overhead and pad-mounted transformers that will be at the end of their useful service life based on risk analysis utilizing age, inspection and available condition test results, over the 2014 to 2018 planning period. The process targets individual transformers that have a high risk of failure and prioritizes replacements based the impact of failure. The age distribution of overhead transformers is not evenly distributed, as the bulk of all overhead transformers were installed during a ten-year distribution system rebuild and voltage conversion window. FFPC's newly developed asset management process has identified that one-hundred-sixteen (116) overhead, and twenty-one (21) pad-mounted transformers will either reach or surpass their UL value of forty five (40) years, as established in the "Kinectrics Report", over the 2014 to 2018 planning period. This number represents approximately 18% of all transformers owned. FFPC is facing somewhat of a "tidal wave" affect, as essentially half of its overhead transformer fleet will either reach or surpass a forty (40) year UL over the next ten (10) years. As such, FFPC is predicting a large increase in failures and is planning on intensifying its capital replacement program. FFPC's most recent equipment failure analysis identified that transformer failures are the number cause of customer interruptions related to equipment failure. Over the next five (5) years, more transformers will reach their UL than have been purchased over the last twenty (20) years. The replacement strategy is to begin replacing high risk transformers with significant impact of failure, and to attempt to smooth the asset population by utilizing FFPC's asset management process. It is also important to note that an additional 250 transformers will reach their UL over the next five year planning period of 2019 to 2023. This underscores the importance that the transformer replacement program be significantly intensified, as per the outputs of the asset management process. FFPC is currently working on developing a tool to analyze transformer loading across its entire asset base, which will further enhance prioritizing replacements. This investment is viewed as a core business reinvestment and as such is treated as non-discretionary. The following table summarizes the planned activities, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	System Renewal	14-18-002	1 Phase Pad Mounted Tx	$11,036		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2014	System Renewal	14-18-002	3 Phase Pad Mounted Tx	$25,106		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2014	System Renewal	14-18-002	Pole Mounted Tx	$47,546		Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
2014	System Renewal	14-18-002	Pole Mounted Tx Spares	$11,960		Replace end-of-life critical spare transformers	1850	EOL - Failure	9 - OH Transformers
2015	System Renewal	14-18-002	1 Phase Pad Mounted Tx	$135,682		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2015	System Renewal	14-18-002	Pole Mounted Tx	$72,234		Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
2015	System Renewal	14-18-002	Pole Mounted Tx Spares	$32,660		Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
2016	System Renewal	14-18-002	1 Phase Pad Mounted Tx	$49,680		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2016	System Renewal	14-18-002	3 Phase Pad Mounted Tx	$66,319		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2016	System Renewal	14-18-002	Pole Mounted Tx	$37,031		Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
2016	System Renewal	14-18-002	Pole Mounted Tx Spares	$31,050		Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
2017	System Renewal	14-18-002	1 Phase Pad Mounted Tx	$123,932		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2017	System Renewal	14-18-002	3 Phase Pad Mounted Tx	$40,213		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2017	System Renewal	14-18-002	Pole Mounted Tx	$118,209		Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
2017	System Renewal	14-18-002	Pad Mounted Tx Spares	$15,525		Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2017	System Renewal	14-18-002	Pole Mounted Tx Spares	$11,500		Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers
2018	System Renewal	14-18-002	1 Phase Pad Mounted Tx	$48,430		Replace end-of-life pad mounted transformers	1850	EOL - Failure Risk	34 - Pad-Mounted Transformers
2018	System Renewal	14-18-002	Pole Mounted Tx	$115,053		Replace end-of-life pole mounted transformers	1850	EOL - Failure Risk	9 - OH Transformers
2018	System Renewal	14-18-002	Pole Mounted Tx Spares	$14,375		Replace end-of-life critical spare transformers	1850	EOL - Failure Risk	9 - OH Transformers

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The main trigger for this project is assets reaching the end of their useful service life posing a high risk of failure. FFPC's most recent equipment failure analysis identified that transformer failures are the number cause of customer interruptions related to equipment failure. FFPC's asset management process by nature targets individual transformers that are most likely to fail (Step 4). As such, transformers are not changed simply because they are in a zone that is being rebuilt due to many assets within a zone coming to the end of their useful service life. FFPC is able to travel to any point along its distribution system within a short time frame, which is a key factor to this strategy. This approach is very efficient as it targets the weakest links throughout FFPC's entire service territory, thereby strengthening the integrity of the distribution system as a whole. FFPC's strategy is also to replace transformers under planned and coordinated conditions, as opposed to under emergency or afterhours conditions, which add unnecessary risk and expense. Capital reinvestments into transformers are essential to sustain FFPC's ability to safely, efficiently, reliably and cost-effectively distribute electricity to its customers. FFPC has aligned the lifecycles of pad-mounted transformer foundations, such that the foundations are changed at an eighty (80) year interval that corresponds to two forty (40) year lifecycles of pad-mounted transformers. As such, FFPC is not planning on replacing any underground foundations during the planning period, as it is not necessary. This has significantly reduced the replacement cost of pad-mounted transformers, as well as it will minimize customer interruptions.

2. Safety

This investment will eliminate potential safety hazards to both the general public and FFPC employees.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

FFPC constructs its transformer settings according to USF Construction Standards, which are commonly used amongst LDC's throughout Ontario. FFPC offers its customers standard voltage offerings that have allowed FFPC to also standardize its transformer fleet.

5. Economic Development

Essentially all material will be purchased from Ontario manufacturers through local or regional suppliers. FFPC's labour force and fleet vehicles will be utilized to complete the project. Additional support services will be supplied by local service providers, such as vacuum excavations and trenching. This project will benefit both the local and provincial economy.

6. Environmental Benefits

FFPC is committed to conducting its business in an environmentally responsible manner. This project will reduce the overall risk of possible environmental incidents associated with transformer failures.

C. Category-specific requirements for each project/activity

System Renewal: FFPC's Overhead and Pad-Mounted Transformer Replacement project is categorized as System Renewal. Due to the relatively narrow window during which FFPC's entire distribution system rebuild and voltage conversion occurred, the age distribution of transformers is not evenly distributed but heavily skewed. FFPC has adopted that transformers will achieve a useful service life of forty years, as per the TUL values established in the "Kinectrics Report". The newly developed asset management process has identified that a disproportionately large percentage (46%) of all transformers will reach or surpass their UL over the next ten years. The evaluation has given FFPC the foresight to intensify its transformer replacement program beginning in 2014, to control projected failure rates, as well as to smooth capital expenditures necessary to replace the assets. As previously mentioned, transformer foundations have been assigned an eighty (80) year lifecycle and as such, FFPC's asset management plan has not identified any necessary replacements over the planning horizon. Planned replacements are prioritized by risk of failure and the associated impact of failure. For example, the regional La Verendrye Hospital is serviced by a transformer that will be at the end of its useful life in 2014, and given the high impact of failure it is planned for replacement in 2014. FFPC is currently developing transformer loading profiles based on its GIS system and the smart meter data available from the AMI system. This asset management system process improvement will assist in assessing risk of failure, from which AEOL projections are derived. The quantity and selection summary of transformer replacements is based on FFPC's asset management process, which revealed the following relative to 2014:

Pole Mounted Transformers Profile		Pole Mounted Transformers Lifecycle Budget Analysis	
629	Quantity	1.8	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL (Adopted)	116	Quantity Reaching Adjusted End of Life Over Forecast Period
28.8	Average Age of Population	$491,617	Total Capital Replacement Cost over Forecast Period
15.73	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
72.0%	% UL Consumed	23.20	Average Replacements Per Year
84.5%	2019 % UL Consumed with no Reinvestment	$98,323	Average Annual Cost Per Year
		$68,782	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$491,617	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

Single Phase Pad Mounted Transformers Profile		Single Phase Pad Mounted Transformers Lifecycle Budget Analysis	
215	Quantity	0.8	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL (Adopted)	35	Quantity Reaching Adjusted End of Life Over Forecast Period
27.7	Average Age of Population	$368,761	Total Capital Replacement Cost over Forecast Period
5.38	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
69.3%	% UL Consumed	7.00	Average Replacements Per Year
81.8%	2019 % UL Consumed with no Reinvestment	$73,752	Average Annual Cost Per Year
		$55,474	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$368,761	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

Three Phase Pad Mounted Transformers Profile		Three Phase Pad Mounted Transformers Lifecycle Budget Analysis	
38	Quantity	1.3	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL (Adopted)	7	Quantity Reaching Adjusted End of Life Over Forecast Period
20.1	Average Age of Population	$147,163	Total Capital Replacement Cost over Forecast Period
0.95	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
50.1%	% UL Consumed	1.40	Average Replacements Per Year
62.6%	2019 % UL Consumed with no Reinvestment	$29,433	Average Annual Cost Per Year
		$20,201	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$147,163	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

It is important to note that FFPC's long range objective is to smooth the age distribution of asset categories to a target of 50% UL Consumed. As per the above tables, it is important to note that the Pole and Single Phase Pad-Mounted Transformer populations only have 28.0% and 30.7% of useful life remaining.

FFPC Replacement costs are based on current costs and are not adjusted to reflect inflation. FFPC's estimated replacement costs are based on the following tables:

Single Phase Pad-Mounted Transformer Replacement Cost	
Tx KVA	Total Cost
15	$ 9,036
25	$ 9,536
37	$ 9,786
50	$ 10,036
75	$ 11,036
100	$ 11,536
150	$ 14,536
167	$ 15,536
333	$ 17,536

Three Phase Pad-Mounted Transformer Replacement Cost	
Tx KVA	Total Cost
112	$ 21,106
150	$ 21,606
225	$ 22,106
300	$ 22,606
350	$ 23,106
500	$ 25,106

Single Phase Pole Mounted Transformer Replacement Cost	
Tx KVA	Total Cost
5	$ 2,815
10	$ 3,015
15	$ 3,215
25	$ 3,415
37	$ 3,915
50	$ 4,415
75	$ 5,915
100	$ 6,415
167	$ 10,415

FFPC has budgeted replacements based on the following asset counts:

Budget Year	Pole Mounted Transformers	Pole Mounted Transformer Replacement Cost	1 Phase Pad-Mounted Transformers	1 Phase Pad-Mounted Transformer Replacement Cost	3 Phase Pad-Mounted Transformers	3 Phase Pad-Mounted Transformer Replacement Cost	Total Quantity	Total Cost
2014	13	$59,506	1	$11,036	1	$25,106	15	$95,648
2015	24	$104,893	12	$135,682	0	$0	36	$240,575
2016	12	$68,081	5	$49,680	3	$66,318	20	$184,080
2017	31	$129,708	12	$123,932	3	$55,737	46	$309,378
2018	36	$129,427	5	$48,430	0	$0	41	$177,857
Total	116	$491,617	35	$368,760	7	$147,162	158	$1,007,541

5.4.5.2.a.iii. 14-18-003 (System Renewal): Primary UG Cable Replacement and Rejuvenation Program

Investment Category: System Renewal		**Project Start Date:** Jan.1, 2014
Project Title: Primary UG Cable Replacement and Rejuvenation Program		**Project End Date:** Dec. 31, 2018
Asset Category(s): Primary TR XLPE Cables in Duct		**Project Driver(s)**: End-of-Life, Risk of Failure
USoA Account: 1845 - UG Conductor and Devices	**Tot. 2014 - 2018 Cap. Cost:** $180,537 **Tot. 2014 - 2018 O&MA Costs:** $0	**Ave Annual Cap. Cost:** $36,107

A. General information on the Project/Activity

FFPC's asset management process annually identifies primary underground TR XLPE cable runs that are at the end of their useful service life based on an age, inspection and condition testing analysis. The process targets individual cable runs that have a high risk of failure. The pace at which the conductors reach the end of their useful service life is a function of their age, physical environment and operating conditions, such as electrical loading. As a direct result of FFPC's entire distribution system being rebuilt over a short period of time, followed by an economic boom, a large portion of underground primary conductors are of the same vintage. As such, FFPC faces an increasing volume of cables that are reaching the end of their useful service life. Due to the extremely cold and long winters, primary underground cables can practically only be replaced from the end of May to the end of October, which is roughly during half of the calendar year. As such, FFPC's strategy has been to replace primary underground cables on a proactive basis, when they have a high probability of failure. Cable replacements are prioritized based on their impact of failure. FFPC is also planning on trialing silicone injection cable rejuvenation on its longer cable runs that are housed in concrete encased ducts. If FFPC is able to extend their life by approximately 20 years through silicone injection, the projected end of life would coincide with the end of life of the greater than 50 kV transformer station in 2034, at which time the cable runs will become obsolete. The following table summarizes the planned activities, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	System Renewal	14-18-003	Non-Profit Housing - 400 Blk Sixth St W - S118A To AT15	$4,642		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2014	System Renewal	14-18-003	Sixth St Non-Profit Housing	$1,598		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2014	System Renewal	14-18-003	Rainy Crest	$10,010		Replace end-of-life primary underground cables to nursing home.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2015	System Renewal	14-18-003	1557 Colonization Rd W U/G	$8,609		Replace end-of-life primary underground cable servicing residential area	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2015	System Renewal	14-18-003	UG Feeder Cable Condition Testing & Rejuvenation Pilot	$28,000		Rejuvenate end-of-life primary underground feeder cables - pilot silicone injection technology project.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2016	System Renewal	14-18-003	Westfort Apartments	$2,457		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2016	System Renewal	14-18-003	Green Manor Apartments	$2,542		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2016	System Renewal	14-18-003	Rose Manor Apartments	$1,574		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2017	System Renewal	14-18-003	Rainbow Motel	$917		Replace end-of-life primary underground cables to multi-residential business complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2017	System Renewal	14-18-003	Armstrong Apartments	$659		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2017	System Renewal	14-18-003	Shevlin Towers West	$1,667		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2017	System Renewal	14-18-003	Shevlin Towers East	$1,672		Replace end-of-life primary underground cables to multi-residential building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2017	System Renewal	14-18-003	Feeder UG Cable Refurbishment Phase 1	$75,000		Rejuvenate end-of-life primary underground feeder cables. Attempt to sustain cables until Transformer Station as whole is at its end-of-life in 2034, at which time cables become obsolete.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2018	System Renewal	14-18-003	Strachan Place - from switch S22-B	$9,874		Replace end-of-life primary underground cables in multi-residential area.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2018	System Renewal	14-18-003	Riverview Cemetery	$5,741		Replace end-of-life primary underground cables to public municipal building complex.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2018	System Renewal	14-18-003	CIBC	$575		Replace end-of-life primary underground cables to priority business customer.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct
2018	System Renewal	14-18-003	Feeder UG Cable Refurbishment Phase 2	$25,000		Rejuvenate end-of-life primary underground feeder cables. Attempt to sustain cables until Transformer Station as whole is at its end-of-life in 2034, at which time cables become obsolete.	1845	EOL - Failure Risk	29 - Primary TR XLPE Cables in Duct

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The main trigger of this project and its activities is assets reaching the end of their useful service life, posing a high risk of failure. FFPC's asset management process by nature targets individual assets (cable runs) that are most likely to fail (Step 4). As such, cables are not changed simply because they are in a zone that is being rebuilt due to many assets within a zone coming to the end of their useful service life. The lifecycles of underground cable ducts have been adjusted to align with two lifecycles of the cables that they house. As such, underground ducts are planned for replacements every 80 years. As previously mentioned, FFPC is planning on trialing silicone injection technology on larger conductor runs which are concrete encased, to extend their service life until 2034 at which time the cables will become obsolete. The planned cable replacements and rejuvenations are not expected to require underground ducting to be replaced, and as such the cost of the replacement is kept to a minimum. This project will benefit the overall reliability of the distribution system at the feeder level, as many of the cable runs are utilized to connect distribution feeders to the distribution station. As such, the investment will be of benefit to all customers, and is deemed non-discretionary as it underpins overall distribution system reliability and performance.

2. Safety

Not applicable.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

Not Applicable.

5. Economic Development

Essentially all material will be sourced through local or regional suppliers. FFPC's labour force and fleet vehicles will be utilized to complete the project. This project will benefit both the local and provincial economy.

6. Environmental Benefits

FFPC is committed to conducting its business in an environmentally responsible manner. This project will reduce the overall risk of environmental incidents occurring as a direct result of underground cable failures.

C. Category-specific requirements for each project/activity

System Renewal: FFPC's Primary UG Cable Replacement and Rejuvenation project is categorized as System Renewal. Due to the relatively narrow window during which FFPC's entire distribution system rebuild and voltage conversion occurred, followed by an economic boom, the age distribution of the

cables is not evenly distributed but heavily skewed. FFPC has adopted that underground Primary TR XLPE Cables in Duct will achieve a useful service life of forty years, as per the TUL values established in the "Kinectrics Report". The newly developed asset management process has identified that a disproportionately large percentage (73.5%) of all underground primary conductor runs will reach or surpass their UL over the next twenty years. The evaluation has given FFPC the foresight to intensify its replacement and refurbishing program beginning in 2014, to control projected failure rates, as well as to smooth capital expenditures necessary to replace the assets. Planned replacements are prioritized by risk of failure and the associated impact of failure. FFPC is currently developing transformer loading profiles based on its GIS system and smart meter data available from the AMI system. The transformer loading profiles can be utilized to indicate conductor loading as well. This asset management system process improvement will assist in assessing risk of failure, from which AEOL projections are derived. The quantity and selection summary of cable replacements is based on FFPC's asset management process, which revealed the following relative to 2014:

Total Cable Length of U/G Primary TR XLPE Cables In Duct Profile		**Total Cable Length UG Primary TR XLPE Budget Analysis**	
30724	Quantity (Meters)	412	10 Year Historic Replacement/Installation Rate (Units/Year)
40	UL (Adopted)	8750	Quantity Reaching Adjusted End of Life Over Forecast Period
27.1	Average Age of Population	$294,020	Total Capital Replacement Cost over Forecast Period
768.10	Ideal Equalized Annual Replacement Rate (Meters/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
67.7%	% UL Consumed	1750.06	Average Replacements Per Year
80.2%	2019 % UL Consumed with no Reinvestment	$58,804	Average Annual Cost Per Year
		$23,292	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$80,537	2014 - 2018 Total Allocated Capital Replacement Amount
		$100,000	2014 - 2018 Total Allocated Capital Refurbishment Amount

5.4.5.2.a.iv. 14-18-004 (System Access): Over 50 kV Transformer Station - Renewable Enabling Improvements

Investment Category: System Access		**Project Start Date:** Jan.1, 2014
Project Title: Over 50 kV Transformer Station - Renewable Enabling Improvements		**Project End Date:** Dec. 31, 2018
Asset Category(s): Digital & Numeric Relays, Remote SCADA, Communication		**Project Driver(s)**: Mandated Service Obligations,
USoA Account: 1531 - Renewable Connection Capital Deferral Account	**Tot. 2014 - 2018 Cap. Cost:** $167,000 **Tot. 2014 - 2018 O&MA Costs:** $15,700	**Ave Annual Cap. Cost:** $33,400

A. General information on the Project/Activity

FFPC is planning to modernize the 1970's protection and control system of its greater than 50 kV Transformer Station "Fort Frances MTS". FFPC's most notable limitations towards accommodating renewable generation are the lack of insight into individual feeder loading from which generation connection constraints are established, as well as the inability to accommodate reverse power flows at any level at the station. The final objective of this multiyear project will be for the transformer station to be able to accommodate reverse power flow, as well as the deployment of a fully operational Remote SCADA system. The improvements will allow FFPC to monitor the performance of core station components, as well as of individual feeders, which will support several Smart Grid Mandate objectives. The improved protection and station oversight will also significantly increase the connection capacity for renewable generation. It is important to note that FFPC is also seeking the recovery of two prior year capital investments, totaling $62,673, for the completion of phases one and two of the conversion project. The following table summarizes the planned activities, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group:

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	System Access	14-18-004	Transformer T1 Protection	$25,000	$2,500	REG Investment - Transformer Station power transformer T1 control and relaying upgrade.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
2014	System Access	14-18-004	Transformer T2 Protection	$25,000	$2,500	REG Investment - Transformer Station power transformer T2 control and relaying upgrade.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
2015	System Access	14-18-004	Station Data Acquisition System	$20,000	$2,000	REG Investment - install data acquisition system to connect to station IED's (intelligent electronic devices).	1531	Mandated Service Obligations	43 - Remote SCADA
2015	System Access	14-18-004	Station Communication Network Installation	$20,000	$2,000	REG Investment - Install local area network at TS to enable connection of IED's and access to operating data.	1531	Mandated Service Obligations	G8 - Communication
2016	System Access	14-18-004	Station OCB Protection	$20,000	$2,000	REG Investment - Upgrade station independent breaker controls and protection.	1531	Mandated Service Obligations	21 - Digital & Numeric Relays
2017	System Access	14-18-004	Station Supervisory Control	$45,000	$3,500	REG Investment - Install station controller and commission station supervisory control (monitor operating conditions and perform appropriate control actions currently performed manually).	1531	Mandated Service Obligations	43 - Remote SCADA
2018	System Access	14-18-004	Station DC System Monitoring & Remote Annunciation	$12,000	$1,200	REG Investment - Install supervisory control over auxiliary station components including DC systems.	1531	Mandated Service Obligations	43 - Remote SCADA

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The planned investments are triggered by the mandate to facilitate the connection of renewable generation. Secondary drivers include the accomplishment of many Smart Grid Mandate objectives under the Customer Control, Power System Flexibility and Adaptive Infrastructure categories. This investment will satisfy priorities 2 and 3 of FFPC's capital Investment Priorities which are: ensuring compliance to regulatory and legal obligations; and meeting the needs and preference of customers. As such, this project is ranked higher than the majority of capital investments that are planned for replacing, sustaining or retiring assets that are at the end of their useful service life, as determined by the asset management process.

2. Safety

This investment will ensure that the transformer station "Fort Frances MTS" can safely continue to accommodate the increasing demand for renewable generation connections, which will result in reverse power flow operating conditions in the near future.

3. Cyber-security, Privacy

FFPC will ensure that its communication network and the IED's on it, are configured according to best industry practices and in compliance to corporate security and privacy policies.

4. Co-ordination, Interoperability

The equipment selected to modernize the transformer station protection and controls is commonly used throughout North America. Supervisory control system and IED data will be made available for interested stakeholders, such as Regional Transmitters or the IESO, through industry standard communication protocols and platforms.

5. Economic Development

Essentially all material will be purchased through local or regional suppliers. Local and regional labour forces will also be used to install and configure the communication network and IED's. This project will support Ontario's economic growth and job creation.

6. Environmental Benefits

This investment will increase the connection capacity of renewable generation to FFPC's distribution system.

C. Category-specific requirements for each project/activity

System Access: FFPC plans to smooth out expenditures over a seven year horizon for rate stability purposes, and as such annual planned expenditures are at or below FFPC's annual capital investment materiality threshold of $50,000. FFPC believes that this approach aligns with the OEB's objective of "pacing and prioritizing capital investments to promote predictability in rates and affordability for customers." The installation of transformer station protection equipment requires the expertise of third-party service providers, as this expertise is not available in the Fort Frances area. FFPC has to rely on external service providers to commute to Fort Frances to perform this type of specialized work. FFPC has taken measures to minimize the overall cost of these planned expenditures, by coordinating the installation of renewable generation enabling improvements to follow regularly scheduled annual maintenance work that is also outsourced to the same external service provider. This will reduce duplication of travelling, mobilization and demobilization costs. Without this synergy FFPC's installation expenses would be approximately 20% higher. In the event that a large scale generator was to request connecting to FFPC's distribution system, the investments would have to be intensified over a much shorter timeframe to accommodate the generation facility. The letter of comment received by the OPA supports FFPC's strategy of pacing investments. Since the receipt of the letter, FFPC was contacted directly by the OPA to advise of 10 MW of increased renewable generation capacity being allocated to Northwestern Ontario. As such, FFPC anticipates receiving increased volumes of renewable generation connection applications. Based on the 2011 to 2013 generator connections, FFPC is projecting to connect an additional 312 kW of photovoltaic generation capacity over the planning horizon. In addition to this, FFPC has received expressions of interest from several OPA Relocation Program applicants with a total generation capacity of 360 kW. At the time of submission, 20kW of this capacity is nearing completion of construction. Refer to section 5.4.3 for a detailed analysis of FFPC's ability and plan to accommodate renewable generation connections.

5.4.5.2.a.v. 14-18-005 (General Plant): Fleet Vehicle Replacement Program

Investment Category: General Plant		**Project Start Date:** Jan.1, 2014
Project Title: Fleet Vehicle Replacement Program		**Project End Date:** Dec. 31, 2018
Asset Category(s): Vehicles		**Project Driver(s)**: Maint. & Capital Support, Non System Physical Plant
USoA Account: 1930 - Transportation Equip.	**Tot. 2014 - 2018 Cap. Cost:** $403,000 **Tot. 2014 - 2018 O&MA Costs:** $0	**Ave Annual Cap. Cost:** $80,600

A. General information on the Project/Activity

FFPC's asset management process governs the life of distribution plant assets, as well as fleet vehicles (transportation equipment). Over the 2014 to 2018 planning horizon the asset management process has identified that a Double Bucket Truck, two service vehicles, a reel stringing & tensioning trailer, as well as a chipper trailer will reach or surpass their Maximum Useful service life as established in the Kinectrics Report. FFPC has adopted a maximum target life expectancy of fifteen (15) years for trucks & buckets, and twenty (20) years for trailers. Support vehicles are crucial in allowing employees to work safely and efficiently. Maintaining a reliable fleet is very important to business efficiency, as FFPC does not have fleet vehicle redundancy. Without fleet vehicle redundancy, a vehicle breakdown could result in considerable job site delays. FFPC's fleet vehicle replacements have been planned around core distribution plant asset replacements to smooth annual capital budget requirements. The following table summarizes the planned activities, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group:

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	General Plant	14-18-005	Replace 1978 Fort Garry Industries Cable Reel Trailer	$50,000		Replace end-of-life cable stringing and tensioning trailer.	1930	Non-System Physical Plant	G2 - Vehicles
2015	General Plant	14-18-005	Replace 1999 Ford Pickup	$38,000		Replace end-of-life crew service/support vehicle.	1930	Non-System Physical Plant	G2 - Vehicles
2016	General Plant	14-18-005	Replace 2003 Ford 4x4 Half Ton	$40,000		Replace end-of-life crew service/support vehicle.	1930	Non-System Physical Plant	G2 - Vehicles
2018	General Plant	14-18-005	Replace Chipper Trailer	$25,000		Replace end-of-life chipper trailer to support vegetation management maintenance program.	1930	Non-System Physical Plant	G2 - Vehicles
2018	General Plant	14-18-005	Replace 2004 Altec Double Bucket Truck	$250,000		Replace end-of-life double bucket truck, to support maintenance, capital and operational activities.	1930	System Cap / Maint Support	G2 - Vehicles

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

FFPC's newly developed asset management process and capital planning process have triggered planning for these fleet vehicle replacements, as they are approaching the end of their useful service life. It is worth noting that FFPC's fleet vehicles are replaced according the Maximum useful life criteria established by the Kinectrics Report, representing best industry practices. Fleet vehicle replacements are planned around core distribution system asset replacements, in order to smooth annual budget requirements. Maintaining a healthy vehicle fleet supports public and employee safety, and ensures that capital, maintenance and operational jobs are conducted efficiently.

2. Safety

Replacing aging fleet vehicles supports the overall safety of employees and the general public.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

FFPC's fleet vehicles are suitable for facilitating distribution line-work on both FFPC's distribution system and on that owned by neighbouring distributors. As such, FFPC's fleet vehicles are available for emergency mutual assistance support to all neighbouring distributors.

5. Economic Development

Fleet vehicles are sourced mainly through Ontario suppliers, who often utilize Ontario manufacturers. Any necessary repairs or maintenance work to fleet vehicles is performed locally. As such, this investment will support the local and provincial economy.

6. Environmental Benefits

The replacement of aging fleet vehicles will reduce overall gas emissions, as new vehicle designs offer improved emission control systems.

C. Category-specific requirements for each project/activity

General Plant: FFPC's electrical distribution operation would be crippled without the assistance of fleet vehicles. Traditional work practices involved manual climbing of poles, and handling of pole line hardware. A comparison could be made to office business efficiency with the removal of computers. Fleet vehicles allow employees to utilize more efficient and safe work practices when constructing, maintaining or operating distribution systems. FFPC views fleet vehicles as essential tools that allow employees to work in a safe and efficient manner. All fleet vehicles are carefully selected to ensure that they meet the needs of the local distribution environment, such as operating under extreme cold and snow covered conditions. All customers across all customer classes will benefit from these investments. As at 2014, FFPC's targeted % Maximum Useful Life (MUL) consumed for the Trucks and Buckets

population is 53.3% and 130% for Trailers. If FFPC were not to replace the fleet vehicles, by 2019 the % MUL consumed for the Trucks and Buckets population would escalate to 86.7%. As such, the investment is aligned with sustaining the lifecycle of FFPC's fleet vehicles. The quantity and selection summary of vehicle replacements is based on FFPC's asset management process, which revealed the following relative to 2014:

Trucks & Buckets Profile		Trucks & Buckets Lifecycle Analysis	
7	Quantity	0.4	10 Year Historic Replacement/Installation Rate (Units/Year)
15	UL (Adopted)	3	Quantity Reaching Adjusted End of Life Over Forecast Period
8.0	Average Age of Population	$328,000	Total Capital Replacement Cost over Forecast Period
0.47	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
53.3%	% UL Consumed	0.60	Average Replacements Per Year
86.7%	2019 % UL Consumed with no Reinvestment	$65,600	Average Annual Cost Per Year
		$53,400	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$328,000	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

Trailers Profile		Trailers Lifecycle Budget Analysis	
2	Quantity	0.0	10 Year Historic Replacement/Installation Rate (Units/Year)
20	UL (Adopted)	2	Quantity Reaching Adjusted End of Life Over Forecast Period
26.0	Average Age of Population	$75,000	Total Capital Replacement Cost over Forecast Period
0.10	Ideal Equalized Annual Replacement Rate (Units/Yr)	$0	Total Capital Refurbishment Cost over Forecast Period
130.0 %	% UL Consumed	0.40	Average Replacements Per Year
155.0 %	2019 % UL Consumed with no Reinvestment	$15,000	Average Annual Cost Per Year
		$3,750	Ave. Annual Reinvestment Need Based on FFPC Adopted UL
		$75,000	2014 - 2018 Total Allocated Capital Replacement Amount
		$0	2014 - 2018 Total Allocated Capital Refurbishment Amount

5.4.5.2.a.vi. 14-14-006 (System Access): Elimination of Long Term Load Transfers

Investment Category: System Access		**Project Start Date:** Jan.1, 2014
Project Title: Elimination of Long Term Load Transfers		**Project End Date:** Dec. 31, 2014
Asset Category(s): Fully Dressed Wood Poles, OH Conductor, OH Transformers, Primary TR XLPE Cables in Duct, Ducts		**Project Driver(s)**: Mandated Service Obligations
USoA Account: 1830, 1835, 1840, 1845, 1850	**Tot. 2014 - 2018 Cap. Cost:** $371,739 **Tot. 2014 - 2018 O&MA Cost:** $18,587	USoA Cost Allocation: 1830 - $294,681; 1835 - $9,180; 1840 - $27,000; 1845 - $2,298; 1850 - $38,580

A. General information on the Project/Activity

FFPC is the "Geographic Distributor" of fourteen (14) customers that are located in three pockets along the edge of municipal boundaries that define FFPC's licensed distribution service territory. Section 6.5.4 of the DSC requires that the Geographic Distributor shall either:

a. negotiate with a physical distributor that provides load transfer services so that the physical distributor will be responsible for providing distribution services to the customer directly, including application for changes to the licensed service areas of each distributor; or
b. expand the geographic distributor's distribution system to connect the load transfer customer and service that customer directly.

FFPC's licensed distribution service territory is relatively compact and the LTLT customers are all located in areas very conducive for future municipal expansion, as well as for hosting renewable generation. As such, FFPC is planning to expand its distribution feeders in the three locations, to be able to service the customers directly. The estimated total expansion cost is $371,739 and annual O&M costs are estimated to increase by $18,587. The expansions will also allow FFPC to be able to distribute the benefits of a 1905 Historic Power Agreement to the LTLT customers. The benefits currently cannot be distributed to LTLT customers, as the Physical Distributor (Hydro One Networks Inc.) is metering and billing them. The distribution system expansions will eliminate these long standing issues. It is also worth noting that FFPC has been formally approached four (4) of the LTLT customers over the last year alone, requesting that they be connected to FFPC's distribution system. The following table summarizes the planned activities, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group:

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	System Access	14-14-006	LTLT Elimination Pole Lines (88 Pri Spans)	$294,681	$14,734	Overhead distribution feeder pole line expansions to connect to LTLT customers	1830	Mandated Service Obligations	1 - Fully Dressed Wood Poles
2014	System Access	14-14-006	LTLT Elimination Conductor	$9,180	$459	Primary conductor for LTLT pole line extensions	1835	Mandated Service Obligations	8 - OH Conductors
2014	System Access	14-14-006	LTLT Elimination Directional Bore & Conduit	$27,000	$1,350	Directional bore underneath CNR right-of-way and install conduit for feeder expansion to connect to LTLT customer.	1840	Mandated Service Obligations	40 - Ducts
2014	System Access	14-14-006	LTLT Elimination Pri UG Conductor	$2,298	$115	Install UG primary conductor in duct (across CNR right-of-way), to extend feeder to connect to LTLT customer.	1845	Mandated Service Obligations	29 - Primary TR XLPE Cables in Duct
2014	System Access	14-14-006	LTLT Elimination Transformers	$38,580	$1,929	Install new transformer to supply LTLT customers from expanded feeders	1850	Mandated Service Obligations	9 - OH Transformers

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

As previously mentioned the main trigger for this project is Section 6.5.4 of the DSC; however, this project will resolve a long standing customer service and jurisdictional issue. This investment will satisfy priorities 2 and 3 of FFPC's capital investment priorities which are: ensuring compliance to regulatory and legal obligations; and meeting the needs and preference of customers. As such, this project is ranked higher than the majority of capital investments that are planned for replacing, sustaining or retiring assets that are at the end of their useful service life. This project will also give FFPC's young line crew the opportunity to undertake system expansion and voltage conversion work that has not been conducted since the end of the local economic boom in the late 1980's. The distribution system expansion will also support future municipal load growth, as all three feeder expansions are situated in areas conducive for municipal expansion. The nature of one of the three expansion locations will involve crossing a CN Railroad right-of-way, which will unlock electrical utility access to approximately 15.4% of FFPC's licensed distribution service territory that is currently not developed. All three expansions combined will unlock access to approximately 25.4% of FFPC's service territory that is not developed. As Fort Frances is also very conducive to hosting photovoltaic renewable generation, the feeder expansions offer considerable improved access for potential renewable generation facilities.

2. Safety

FFPC is committed to ensuring that the distribution feeder expansions are performed in a safe manner, and that general public as well as employees are not subjected to undue hazards.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

FFPC constructs its distribution feeders to USF Construction Standards, which are commonly used amongst most LDC's throughout Ontario.

5. Economic Development

Essentially all material will be purchased from Ontario manufacturers through local or regional suppliers. FFPC's labour force and fleet vehicles will be utilized to complete the project. Additional support services will be supplied by local service providers, such as vacuum excavations and trenching. The distribution feeder expansions will also unlock considerable access to electrical supply, to encourage municipal and renewable generation growth. This project will benefit both the local and provincial economy.

6. Environmental Benefits

This project will support facilitating renewable generation by providing improved access to distribution feeders along municipal properties conducive to hosting such generation. FFPC is committed to conducting its business in an environmentally responsible manner. This project will not negatively impact the well being of the environment.

C. Category-specific requirements for each project/activity

System Access: This project is driven by the requirements of Section 6.5.4 of the DSC. FFPC is awaiting OEB approval of this capital expansion project and will commence construction upon receiving it. FFPC is targeting completing the feeder expansions by December 31, 2014. Several affected LTLT customers have approached FFPC over the last year to personally request being connected to FFPC's distribution system. Twelve (12) of the fourteen (14) LTLT customers are located along an East-West roadway (Frog Creek Road) that acts as a North - South boundary of FFPC's licensed service territory from the outlying service territory serviced by HONI. A large section of the connecting north-south roadway (McIrvine Road) located within FFPC's service territory is not electrically serviced by any distribution feeders. As such, FFPC is proposing to extend its distribution feeder along the north-south roadway (McIrvine Road) to service the unserviced portion of the roadway, as well as to connect to the LTLT customers located at the end of it. Many properties adjacent to the unserviced portion of McIrvine Road are well suited for residential or commercial use, including hosting renewable generation facilities. The expansion will also offer direct access to FFPC's Transformer Station, enabling the connection of large scale renewable generation in the expanded service area. Most of the Physical Distributor's (HONI's) assets will still be required to service customers outside of FFPC's licensed service territory, as they are located along the north side of Frog Creek Road, including the Fort Frances Regional Airport. The expansion will support the well being of the local community by potentially attracting new residents and businesses to the newly serviced areas. Another benefit of this project will be that an alternate supply of electricity will in close proximity to the Fort Frances Airport, in the event of an emergency.

5.4.5.2.a.vii. 14-14-007 (Various): 2014 Misc. Small Capital Projects

Investment Category: Various		**Project Start Date:** Jan.1, 2014
Project Title: 2014 Misc. Small Capital Projects		**Project End Date:** Dec. 31, 2014
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. 2014 - 2018 Cap. Cost:** $106,750 **Tot. 2014 - 2018 O&MA Cost:** $750	USoA Cost Allocation: Various

A. General information on the Project/Activity

FFPC's asset management process annually identifies assets that are at the end of their useful service life based on an age, inspection and condition testing analyses. Most of the small capital projects listed below are driven by the need of sustaining the lifecycle of existing assets owned. Non lifecycle related investments are driven by FFPC's capital planning process, to accomplish other business objectives such as improving business efficiency or meeting customer expectations. The following table summarizes the planned small capital activities for 2014, as well as their Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2014	General Plant	14-14-007	Misc Building Improvements	$2,000		Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
2014	General Plant	14-14-007	Building Heater Replacements	$3,000		Transformer Station heater replacements	1808	Non-System Physical Plant	G5 - Station Buildings
2014	General Plant	14-14-007	Cable Reel Stands	$2,000		Install cable reel stands at Operations Centre	1908	System Cap / Maint Support	G3 - Administrative Buildings
2014	General Plant	14-14-007	Replace Shelving	$2,000		Upgrade stores area shelving at Operations Centre	1908	Non-System Physical Plant	G3 - Administrative Buildings
2014	General Plant	14-14-007	Meter Room Flooring	$2,500		Misc. meter room improvements - replace flooring and fixtures	1908	Non-System Physical Plant	G3 - Administrative Buildings
2014	General Plant	14-14-007	Office A/C	$1,000		Install air conditioning in lunch room	1908	Non-System Physical Plant	G3 - Administrative Buildings
2014	General Plant	14-14-007	Admin Area Renovation	$3,500		Misc. Main Office renovations - Reception area	1908	Non-System Physical Plant	G3 - Administrative Buildings
2014	General Plant	14-14-007	Misc. Main Office furniture replacements	$2,000		Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2014	General Plant	14-14-007	Misc. Operations Centre furniture replacements	$1,000		Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2014	General Plant	14-14-007	Operations Centre Copier	$4,000		Replace Operations Centre end-of-life multimedia centre	1920	Non-System Physical Plant	G1 - Office Equipment
2014	General Plant	14-14-007	Computer Hardware	$5,000		Director laptop computers to support real-time communication and paperless information distribution.	1920	Non-System Physical Plant	G6 - Computer Equipment
2014	General Plant	14-14-007	AMI MAS Server Replacement	$4,000		Replace end-of-life AMI system Master Application Server.	1920	Non-System Physical Plant	G6 - Computer Equipment
2014	General Plant	14-14-007	AutoCad License	$2,000	$400	Upgrade AutoCad drafting software for technical blue print management	1611	Non-System Physical Plant	G6 - Computer Equipment
2014	General Plant	14-14-007	MS Office Productivity Package	$2,000		Director MS office productivity package to support real-time communication and paperless information distribution.	1611	Non-System Physical Plant	G6 - Computer Equipment
2014	General Plant	14-14-007	Small Tools	$5,000		Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
2014	General Plant	14-14-007	Label Printer - Asset Labeling	$2,500		Asset labeler for asset identification initiative (GIS).	1940	Business Operation Eff	G7 - Equipment
2014	General Plant	14-14-007	Transformer Safe Transport Kit	$3,000		Transformer safe transport kit to mitigate risk of environmental spill from handling increased volume of failing transformers.	1940	Obj - Safety	G7 - Equipment
2014	System Renewal	14-14-007	DC System Battery Cell Replacement	$2,000		Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
2014	System Renewal	14-14-007	UG Service Replacement	$2,000		Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
2014	System Renewal	14-14-007	OH Service Replacement	$2,000		Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
2014	System Renewal	14-14-007	CT/PT and Cabinet Replacements	$2,500		Replace end-of-life CT & PT metering settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)

2014	System Renewal	14-14-007	Meter Replacements	$3,250		Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
2014	System Service	14-14-007	Primary Insulator Replacements	$10,000		Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
2014	System Service	14-14-007	Air Break Switches Insulator Replacements	$4,500		Air break switch primary insulator replacements as per inspection findings	1835	Obj - Reliability	4 - OH Line Switch
2014	System Service	14-14-007	Robert Moore Air Break Switch Relocation	$28,000		Remove, replace and relocate air break switch from School Yard	1835	Obj - Safety	4 - OH Line Switch
2014	System Service	14-14-007	Mobile Work Tablets	$2,500		Purchase mobile work tablets for transition to electronic inspection forms and for line crew on-site access to technical documentation.	1920	Other Performance/Functionality	G6 - Computer Equipment
2014	System Service	14-14-007	Elster Tx Primary Data Logger and Meter	$3,500	$350	Primary meter for transformer setting, to support identification of theft of power and transformer loading profile development.	1945	Obj - Safety	G7 - Equipment

5.4.5.2.a.viii. 15-15-008 (System Service): Transformer Station - Power Transformer Fire Barrier

Investment Category: System Service		**Project Start Date:** Jan.1, 2015
Project Title: Transformer Station - Power Transformer Fire Barrier		**Project End Date:** Dec. 31, 2015
Asset Category(s): Station Buildings		**Project Driver(s)**: Business Objective - Reliability
USoA Account: 1808	**Tot. 2014 - 2018 Cap. Cost:** $62,000 **Tot. 2014 - 2018 O&MA Cost:** $0	USoA Cost Allocation: 1808 - $62,000

A. General information on the Project/Activity

FFPC has two power transformers at its greater than 50 kV transformer station "Fort Frances MTS" which are in close proximity to one another. Recent discussions with its insurance carrier, as well as with the local pulp and paper mill, have identified that the transformers have the potential of causing structural damage to one another in the event of a catastrophic failure, such as a fire. The main concerns are with containing a potential transformer fire, as well as containing propelled airborne debris. It has been recommended that a custom fire and blast retaining structure be built to isolate the units from one another. Although the probability of a critical failure is very low, the resulting impact of failure is very high, as a loss of both power transformers would not allow FFPC to supply its customer base with electricity. The following table summarizes the planned activity, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group:

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2015	System Service	15-15-008	Transformer Fire Barrier	$62,000		Install fire and blast barrier between power transformer T1 and T2.	1808	Obj - Reliability	G5 - Station Buildings

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The main trigger of this project is to ensure that the overall long term reliability of FFPC's electrical distribution system maintained. This project was identified through in step 5 of FFPC's asset management process, and received top priority for 2015 due to its potential impact on reliability which could affect customer and employee safety.

2. Safety

This project improves the protection of FFPC's transformer station equipment, which are relied upon to support the health, safety and well being of all customers and employees.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

A prototype of this installation is located at the local pulp and paper mill in Fort Frances. FFPC plans to implement essentially the same solution to resolve the potential reliability hazard.

5. Economic Development

FFPC will rely on local material suppliers and contractors to construct the custom fire and blast retaining structure. This project will support both the local and provincial economy.

6. Environmental Benefits

This project is designed to contain a catastrophic failure of an oil filled power transformer. The nature of the project is to minimize the impact associated with a potential failure to its surroundings, which include the environment.

C. Category-specific requirements for each project/activity

System Service: The benefit of this project to customers is that it greatly reduces the probability of a catastrophic equipment failure from impacting the reliability of electricity distributed to them. The investment is essentially an insurance measure in support of the reliability of FFPC's distribution system as a whole. The nature of this project does not involve the deployment of advanced technology. The planning and coordinating of this project is estimated to take up to six months, which aligns its practical implementation with the summer of 2015. The construction of a fire and blast retaining structure is by far the lowest cost solution to isolate the power transformers from one another. It is not practical to relocate the units, or to alter the arrangement of existing equipment in the transformer station yard. As previously mentioned, this investment is a due diligence investment to reduce the probability of suffering extensive damage to transformer station property, plant and equipment.

5.4.5.2.a.ix. 15-15-009 (Various): 2015 Misc. Small Capital Projects

Investment Category: Various		**Project Start Date:** Jan.1, 2015
Project Title: 2015 Misc. Small Capital Projects		**Project End Date:** Dec. 31, 2015
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. 2014 - 2018 Cap. Cost:** $89,250 **Tot. 2014 - 2018 O&MA Cost:** $3,000	USoA Cost Allocation: Various

A. General information on the Project/Activity

FFPC's asset management process annually identifies assets that are at the end of their useful service life based on an age, inspection and condition testing analysis. Most of the small capital projects listed below are driven by the need of sustaining the lifecycle of existing assets owned. Non lifecycle related investments are driven by FFPC's capital planning process, to accomplish other business objectives such as improving business efficiency or meeting customer expectations. The following table summarizes the planned small capital activities for 2015, as well as their Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2015	General Plant	15-15-009	Misc Building Improvements	$2,000		Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
2015	General Plant	15-15-009	Build Outdoor Transformer Shelter	$6,000		Install weather shelter for transformer yard storage area.	1908	System Cap / Maint Support	G3 - Administrative Buildings
2015	General Plant	15-15-009	Replace Shop Rollup Door	$12,000		Replace operations centre rollup garage door.	1908	System Cap / Maint Support	G3 - Administrative Buildings
2015	General Plant	15-15-009	Reg & Finance Area Renovations	$3,500		Misc. Main Office renovations - Finance Area	1908	Non-System Physical Plant	G3 - Administrative Buildings
2015	General Plant	15-15-009	Misc. Main Office furniture replacements	$2,000		Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2015	General Plant	15-15-009	Misc. Operations Centre furniture replacements	$1,000		Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2015	General Plant	15-15-009	PC Replacement	$5,000		Replace end-of-life computers at the Main Office.	1920	Non-System Physical Plant	G6 - Computer Equipment
2015	General Plant	15-15-009	Computer Hardware	$1,000		Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
2015	General Plant	15-15-009	Small Tools	$5,000		Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
2015	System Renewal	15-15-009	DC System Battery Cell Replacement	$2,000		Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
2015	System Renewal	15-15-009	UG Service Replacement	$2,000		Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
2015	System Renewal	15-15-009	OH Service Replacement	$2,000		Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
2015	System Renewal	15-15-009	CT/PT and Cabinet Replacements	$2,500		Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
2015	System Renewal	15-15-009	Meter Replacements	$3,250		Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
2015	System Service	15-15-009	Backup Generator Switch / Install	$4,500		Install transfer switch and panel for connectability to emergency backup generation to supply station lighting and DC battery bank chargers.	1808	Obj - Reliability	G5 - Station Buildings
2015	System Service	15-15-009	Generator	$5,500		Transformer Station backup generator for emergency lighting and DC system charging.	1808	Obj - Reliability	G5 - Station Buildings
2015	System Service	15-15-009	Primary Insulator Replacements	$5,000		Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
2015	System Service	15-15-009	OH Secondary Bus Replacements	$10,000		Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
2015	System Service	15-15-009	Mass Customer Contact System	$15,000	$3,000	Install and commission mass customer contact system to enable contacting customers regarding important event such as power interruptions.	1955	Customer Preference	G8 - Communication

5.4.5.2.a.x. 15-16-010 (System Service): Financial Information System Integration

Investment Category: System Service		**Project Start Date:** Jan.1, 2015
Project Title: Financial Information System Integration		**Project End Date:** Dec. 31, 2015
Asset Category(s): Computer Equipment (Software)		**Project Driver(s)**: Business Objective - Business Efficiency
USoA Account: 1611	**Tot. 2014 - 2018 Cap. Cost:** $60,000 **Tot. 2014 - 2018 O&MA Cost:** $10,000	USoA Cost Allocation: 1611 - $60,000

A. General information on the Project/Activity

FFPC in planning on improving its business efficiency through the acquisition and integration of a modern day Financial Information System (FIS), such as Microsoft Great Planes. The existing system utilized is very limited in functionality and as such does not offer flexible reporting, exporting of data electronically, enhanced data analyses or graphical plotting of data. Financial data is currently transposed from the system into spreadsheets and other support tools manually, from paper printouts requiring the data to be rekeying. A second phase of the project is planned to integrate purchasing and payroll functions into the system. Project costs are mainly attributed to the purchase of the software tool, as well as towards setup, commissioning and integration to support systems. The following table summarizes the planned activities, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group:

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2015	System Service	15-16-010	Financial Information System Phase 1	$40,000	$6,000	Purchase and commission Financial Information System to enable data exports, enhanced reporting and data analysis for planning activities.	1611	Business Operation Eff	G6 - Computer Equipment
2016	System Service	15-16-010	Financial Information System Phase 2	$20,000	$4,000	Integrate payroll and purchasing into FIS system.	1611	Business Operation Eff	G6 - Computer Equipment

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The implementation of a Financial Information System will greatly improve financial oversight, enhance financial planning, automate manual calculation processes, reduce manual rekeying of data into support systems, and simplify core business tasks such as processing of the 1905 Historic Power Agreement, calculating of amortization schedules, preparation of financial reports and RRR reporting. As a small utility, FFPC relies on the integration of good tools to maximize employee efficiency and productivity. The deployment of good tools will ultimately allow FFPC to maintain a minimalistic staff complement, without undermining the long term viability of its business. A modern day financial system offers interoperability with other core business systems, such as the GIS system. FFPC plans on integrating the system with its GIS system, as well as on expanding its scope to encompass the management of purchasing and payroll related functions. FFPC is projecting to have the necessary internal resources available to champion the project implementation throughout 2015 and 2016. FFPC's strategy is to utilize internal staff to minimize implementation costs, as well as to ensure that the system deployed is tailored to FFPC's business needs.

2. Safety

Not Applicable.

3. Cyber-security, Privacy

FFPC recently participated and two IT system audits that were conducted to assess levels of security, as well as to identify opportunities for security improvements. FFPC is committed to ensuring that its IT systems are protected according to internal policies and industry best practices.

4. Co-ordination, Interoperability

The Financial System sought, must have the ability to accommodate electronic information exchange with other core business systems, so as to facilitate IT system interoperability. FFPC will ensure that data can be shared easily as required by both internal and external stakeholders.

5. Economic Development

FFPC will attempt to rely on local or regional software vendors to supply the software. This project is projected to support both the local and provincial economy, as local and provincial resources are required for the project deployment.

6. Environmental Benefits

This project will support FFPC's efforts to shift from paper based work flows to electric information exchanges. As such, FFPC expects its dependency on paper to be significantly reduced.

C. Category-specific requirements for each project/activity

System Service: This project is driven by FFPC'S objective of continually improving its business processes. FFPC's current financial system is very antiquated and lacks modern day functionality such as flexible reporting, electronic export of data into support systems, enhanced data analyses, and graphical plotting of data. Financial data is currently transposed from the system into spreadsheets and other support tools which have to be manually administered. The new system will improve FFPC's ability to mirror the USoA accounting structure, as well as allow for flexible account mapping and reporting to meet the needs of various stakeholders. For example, account groupings for OEB RRR filing purposes are different from account groupings for audited financial statement development purposes. This project targets improving employee efficiency by reducing the need of manual rekeying of financial information into support tools, due to the lack of functionality. This will free up considerable staff time which can then be devoted to more value added tasks. The tool will also support FFPC's asset management and capital planning processes, in that it will support improved decision making by presenting supporting financial information in a more meaningful and intuitive manner. It is estimated that the tool will conservatively increase productivity by 1.5 employee work hour per working day, which translates into approximately $15,000 in increased annual productivity. In regards to cyber security, the system will be deployed onto FFPC's existing network, which is protected according to IT best practices. FFPC is committed to ensuring that its information systems are protected according to internal policies, which are aligned with industry best practices.

5.4.5.2.a.xi. 16-16-011 (System Renewal): Over 50 kV Tx Station - Station Independent Breaker Replacement

Investment Category: System Renewal		**Project Start Date:** Jan.1, 2016
Project Title: Over 50 kV Transformer Station - Station Independent Breaker Replacement		**Project End Date:** Dec. 31, 2016
Asset Category(s): Station Independent Breakers		**Project Driver(s)**: End of Service Life - Failure Risk
USoA Account: 1815 Transformer Station Equipment - Normally Primary above 50 kV	**Tot. 2014 - 2018 Cap. Cost:** $150,000 **Tot. 2014 - 2018 O&MA Cost:** $0	USoA Cost Allocation: 1815 - $150,000

A. General information on the Project/Activity

FFPC owns and operates a greater than 50 kV transformer station "Fort Frances MTS". The newly developed asset management process has identified the stations main Oil Filled Circuit Breaker (OCB) has surpassed its Maximum Useful Life of 65 years, as established in the Kinectrics Report. As the breaker is responsible for protecting the entire station in the event of a critical failure (fault), it has a high impact of failure. Condition tests indicate that the unit is operating at an acceptable level; however, expert advice obtained from Siemen's Canada recommends that the device be replaced by 2016. The following table summarizes the planned activity, by Capital Budget Year, Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group:

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2016	System Renewal	16-16-011	1947 OCB Replacements	$150,000		Replace end-of-life station independent breaker at Transformer Station.	1815	EOL - Failure Risk	17 - Station Independent Breakers

B. Evaluation criteria and information requirements for each Project/Activity

1. Efficiency, Customer Value, Reliability

The main trigger for this project is the output of step 4 of FFPC's asset management, which revealed the unit has surpassed its maximum suggested service life, as established by the "Kinectrics Report". The device is not conducive to running to failure, as that would compromise the protection of the entire transformer station. As the device ensures the overall safety of transformer station property, plant, equipment and personnel, it has been assigned the highest replacement priority for 2016 capital projects. The investment will support FFPC's ability to safely, reliably and efficiently distribute electricity to all of its customers. As such, all customers in all customer classes will benefit from this investment.

2. Safety

This investment ensures that the safety of transformer station property, plant, equipment and personnel are maintained.

3. Cyber-security, Privacy

Not Applicable

4. Co-ordination, Interoperability

Coordinating the breaker replacement will involve joint planning with the regional transmitter HONI, as well as with IESO. All regional stakeholders will be involved in the replacement planning process to ensure proper interoperability.

5. Economic Development

This investment will utilize local and regional labour, as well as all material will be sourced through local or regional suppliers. As such, this project will benefit both the local and provincial economy.

6. Environmental Benefits

This project will reduce the risk of environmental incidents associated with equipment failures at the transformer station.

C. Category-specific requirements for each project/activity

System Renewal: The OCB's are not conducive to running to failure as their failure compromises the overall well being of the transformer station it is designed to protect. FFPC's asset management process has revealed that the unit has surpassed its maximum useful life of 65 years, and therefore poses a high risk of failure. Expert advice obtained from Siemens Canada suggests that the unit be replaced by 2016, and as such FFPC has planned accordingly. The device has the potential of impacting the performance of FFPC's entire distribution system and is therefore by nature very important. Planning for the replacement is expected to require at least one year, as the planning process involves coordination with the regional transmitter, as well as with the IESO.

5.4.5.2.a.xii. 16-16-012 (Various): 2016 Misc. Small Capital Projects

Investment Category: Various		**Project Start Date:** Jan.1, 2016
Project Title: 2016 Misc. Small Capital Projects		**Project End Date:** Dec. 31, 2016
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. 2014 - 2018 Cap. Cost:** $109,750 **Tot. 2014 - 2018 O&MA Cost:** $1,050	USoA Cost Allocation: Various

A. General information on the Project/Activity

FFPC's asset management process annually identifies assets that are at the end of their useful service life based on an age, inspection and condition testing analysis. Most of the small capital projects listed below are driven by the need of sustaining the lifecycle of existing assets owned. Non lifecycle related investments are driven by FFPC's capital planning process, to accomplish other business objectives such as improving business efficiency or meeting customer expectations. The following table summarizes the planned small capital activities for 2016, as well as their Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2016	General Plant	16-16-012	Misc Building Improvements	$2,000		Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
2016	General Plant	16-16-012	Interior Lighting Retrofit	$3,000		Transformer Station T12 lighting replacements	1808	Business Operation Eff	G5 - Station Buildings
2016	General Plant	16-16-012	Yard Landscaping	$3,000		Landscape yard at Operations Centre - Install flower beds and general yard improvements	1908	System Cap / Maint Support	G3 - Administrative Buildings
2016	General Plant	16-16-012	Cable Reel Shelter	$6,000		Install shelter over outdoor cable reel storage area	1908	System Cap / Maint Support	G3 - Administrative Buildings
2016	General Plant	16-16-012	Office Carpeting	$2,500		Replace Main Office carpets.	1908	Non-System Physical Plant	G3 - Administrative Buildings
2016	General Plant	16-16-012	Executive Area Renovations	$3,500		Misc. Main Office renovations - Board Room	1908	Non-System Physical Plant	G3 - Administrative Buildings
2016	General Plant	16-16-012	Misc. Main Office furniture replacements	$2,000		Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2016	General Plant	16-16-012	Misc. Operations Centre furniture replacements	$1,000		Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2016	General Plant	16-16-012	Computer Hardware	$1,000		Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
2016	General Plant	16-16-012	Small Tools	$5,000		Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
2016	General Plant	16-16-012	Main Office Telephone Data Logger	$7,000	$1,050	Purchase and commission Main Office telephone system data logger, to support telephone accessibility related RRR reporting.	1955	Business Operation Eff	G8 - Communication
2016	System Renewal	16-16-012	DC System Battery Cell Replacement	$2,000		Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
2016	System Renewal	16-16-012	T1 Battery Charger	$22,000		Replace end-of-life battery charger for Transformer Station T1 DC system.	1825	EOL - High Performance Risk	15 - Station DC System
2016	System Renewal	16-16-012	UG Service Replacement	$2,000		Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
2016	System Renewal	16-16-012	OH Service Replacement	$2,000		Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
2016	System Renewal	16-16-012	CT/PT and Cabinet Replacements	$2,500		Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
2016	System Renewal	16-16-012	Meter Replacements	$3,250		Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
2016	System Service	16-16-012	115 kV Sky Structure Insulator Replacements	$25,000		Replace Transformer Station primary insulators on sky structure.	1815	Obj - Reliability	23 - Steel Structure
2016	System Service	16-16-012	Primary Insulator Replacements	$5,000		Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
2016	System Service	16-16-012	OH Secondary Bus Replacements	$10,000		Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors

5.4.5.2.a.xiii. 17-17-013 (Various): 2017 Misc. Small Capital Projects

Investment Category: Various		**Project Start Date:** Jan.1, 2017
Project Title: 2017 Misc. Small Capital Projects		**Project End Date:** Dec. 31, 2017
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. 2014 - 2018 Cap. Cost:** $102,750 **Tot. 2014 - 2018 O&MA Cost:** $4,300	USoA Cost Allocation: Various

A. General information on the Project/Activity

FFPC's asset management process annually identifies assets that are at the end of their useful service life based on an age, inspection and condition testing analysis. Most of the small capital projects listed below are driven by the need of sustaining the lifecycle of existing assets owned. Non lifecycle related investments are driven by FFPC's capital planning process, to accomplish other business objectives such as improving business efficiency or meeting customer expectations. The following table summarizes the planned small capital activities for 2017, as well as their Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2017	General Plant	17-17-013	Misc Building Improvements	$2,000		Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
2017	General Plant	17-17-013	Technical Station Renovations	$3,000		Transformer Station technical station renovations	1808	System Cap / Maint Support	G5 - Station Buildings
2017	General Plant	17-17-013	Training Room Carpeting	$2,500		Replace carpeting in the training room located at the Operation Centre.	1908	Non-System Physical Plant	G3 - Administrative Buildings
2017	General Plant	17-17-013	Door Replacements	$2,000		Operations Centre door replacements.	1908	Non-System Physical Plant	G3 - Administrative Buildings
2017	General Plant	17-17-013	Technical Workstation Replacement	$3,500		Misc. Main Office renovations - Technical Office	1908	Non-System Physical Plant	G3 - Administrative Buildings
2017	General Plant	17-17-013	Misc. Main Office furniture replacements	$2,000		Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2017	General Plant	17-17-013	Misc. Operations Centre furniture replacements	$1,000		Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2017	General Plant	17-17-013	Media Centre (Photo Copier)	$11,000		Replace the Main Office end-of-life media centre.	1920	Non-System Physical Plant	G1 - Office Equipment
2017	General Plant	17-17-013	Computer Hardware	$1,000		Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
2017	General Plant	17-17-013	Small Tools	$5,000		Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
2017	System Renewal	17-17-013	DC System Battery Cell Replacement	$2,000		Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
2017	System Renewal	17-17-013	UG Service Replacement	$2,000		Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
2017	System Renewal	17-17-013	OH Service Replacement	$2,000		Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
2017	System Renewal	17-17-013	CT/PT and Cabinet Replacements	$2,500		Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
2017	System Renewal	17-17-013	Meter Replacements	$3,250		Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
2017	System Service	17-17-013	Primary Insulator Replacements	$5,000		Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
2017	System Service	17-17-013	OH Secondary Bus Replacements	$10,000		Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
2017	System Service	17-17-013	Elster "Access Detect" (OMS)	$43,000	$4,300	Purchase and commission Outage Management System, to enable proactive outage alerts and localized customer interaction.	1611	Customer Preference	G6 - Computer Equipment

5.4.5.2.a.xiv. 18-18-014 (Various): 2018 Misc. Small Capital Projects

Investment Category: Various		**Project Start Date:** Jan.1, 2018
Project Title: 2018 Misc. Small Capital Projects		**Project End Date:** Dec. 31, 2018
Asset Category(s): Various		**Project Driver(s)**: Various
USoA Account: Various	**Tot. 2014 - 2018 Cap. Cost:** $62,250 **Tot. 2014 - 2018 O&MA Cost:** $1,300	USoA Cost Allocation: Various

A. General information on the Project/Activity

FFPC's asset management process annually identifies assets that are at the end of their useful service life based on an age, inspection and condition testing analysis. Most of the small capital projects listed below are driven by the need of sustaining the lifecycle of existing assets owned. Non lifecycle related investments are driven by FFPC's capital planning process, to accomplish other business objectives such as improving business efficiency or meeting customer expectations. The following table summarizes the planned small capital activities for 2018, as well as their Investment Category, Parent Project ID, Project Activity Name, Capital Cost, OM&A Cost, Investment Description, USoA Account, Primary Investment Driver and Kinectrics Asset Group.

Capital Budget Year	Investment Category	Parent Project ID	Project Activity Name	Capital Cost	OM&A Cost	Investment Description	USoA Account	Primary Investment Driver	Kinectrics Asset Group
2018	General Plant	18-18-014	Misc Building Improvements	$2,000		Miscellaneous Transformer Station building improvements	1808	System Cap / Maint Support	G5 - Station Buildings
2018	General Plant	18-18-014	Bathroom Renovation	$2,000		Transformer Station bathroom renovations	1808	System Cap / Maint Support	G5 - Station Buildings
2018	General Plant	18-18-014	Window Replacements	$6,000		Replace Operations Centre windows.	1908	Non-System Physical Plant	G3 - Administrative Buildings
2018	General Plant	18-18-014	Main Office Bathroom Renovations	$3,500		Misc. Main Office renovations - Bathroom	1908	Non-System Physical Plant	G3 - Administrative Buildings
2018	General Plant	18-18-014	Misc. Main Office furniture replacements	$2,000		Misc. Main Office furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2018	General Plant	18-18-014	Misc. Operations Centre furniture replacements	$1,000		Misc. Operations Centre furniture replacements	1915	Non-System Physical Plant	G1 - Office Equipment
2018	General Plant	18-18-014	Computer Hardware	$1,000		Replace misc. end-of-life computer hardware.	1920	Non-System Physical Plant	G6 - Computer Equipment
2018	General Plant	18-18-014	Small Tools	$5,000		Misc. small tool replacements	1940	System Cap / Maint Support	G7 - Equipment
2018	General Plant	18-18-014	Phone System Upgrade	$13,000	$1,300	Replace end-of-life Meridian phone system at the Main Office.	1955	Non-System Physical Plant	G8 - Communication
2018	System Renewal	18-18-014	DC System Battery Cell Replacement	$2,000		Transformer Station DC battery bank end-of-life cell replacements	1825	EOL - High Performance Risk	15 - Station DC System
2018	System Renewal	18-18-014	UG Service Replacement	$2,000		Replace end-of-life direct buried secondary conductors	1855	EOL - Failure Risk	31 - Secondary Cables Direct Buried
2018	System Renewal	18-18-014	OH Service Replacement	$2,000		Replace deteriorated overhead services based on inspection findings	1855	EOL - Failure Risk	8 - OH Conductors
2018	System Renewal	18-18-014	CT/PT and Cabinet Replacements	$2,500		Replace end-of-life meter CT & PT meter settings	1860	EOL - Failure Risk	G12 - Current & Potential Transformer (CT & PT)
2018	System Renewal	18-18-014	Meter Replacements	$3,250		Replace failed smart meters	1860	EOL - Failure	G13 - Smart Meters
2018	System Service	18-18-014	Primary Insulator Replacements	$5,000		Primary insulator replacements as per inspection findings	1835	Obj - Reliability	8 - OH Conductors
2018	System Service	18-18-014	OH Secondary Bus Replacements	$10,000		Replace deteriorated secondary bus as per inspection findings	1835	Obj - Reliability	8 - OH Conductors

Appendix 1: OPA Letter of Comment: FFPC Distribution System Plan

OPA Letter of Comment:

Fort Frances Power Corporation

Distribution System Plan











August 30, 2013

ONTARIO POWER AUTHORITY

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Fort Frances Power Corporation – Distribution System Plan

On July 12, 2013, the OPA received a Distribution System Plan ("Plan") from Fort Frances Power Corporation ("FFPC") containing information that complies with the Board's Chapter 5 - Consolidated Distribution System Plan Filing Requirements. The OPA has reviewed the Plan of FFPC and has provided its comments below.

OPA FIT/microFIT Applications Received

On pages 12 - 13 of its Plan, FFPC indicates that currently it has connected 7 microFIT projects, totalling 61 kW in capacity. As well, one additional microFIT application of 10 kW has been built but is currently not operational because it failed the OPA's contract acceptance requirements. FFPC indicates that it understands this project may resume production under a new contract in the near future. FFPC has also connected 1 FIT application with total capacity of 100 kW.

According to OPA's information as of August 20, 2013, the OPA has received and offered contracts to 7 microFIT applications, totalling 61 kW. The OPA has also received and offered a contract to 1 FIT application with a capacity of 100 kW.

The OPA notes that on page 11 of the Plan, FFPC has received several inquiries from large scale generator applications but that no formal applications were submitted to FFPC. On June 12, 2013, the OPA received a directive from the Minister of Energy which states that the OPA shall discontinue Large

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FIT Project applications submitted prior to the date of this direction which have yet to receive a FIT contract. As a result of this change to the FIT Program Rules, the OPA will be discontinuing any large FIT applications that it has received for connection in FFPC's distribution service territory.

The OPA finds that FFPC's Plan is consistent with the OPA's information regarding renewable energy generation applications to date. The OPA has initiated a discussion with FFPC, based on a request found on page 15 of their Plan, in order to provide guidance on the subject of microFIT and FIT project relocations. The OPA intends to update FFPC with new information on relocations in its service territory as it becomes available to facilitate FFPC's ability to plan for and accommodate connections for these generation projects.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

At this time, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan ("IRRP"), has been completed for the FFPC service territory. FFPC indicates that it has experienced, and expects to continue to experience in the near future, reductions in demand and in the volume of electricity delivered through its single supply point due to distributed generation, conservation and demand management, and the state of the local economy. Although FFPC has not identified any renewable generation enabling capital expansion expenditures, FFPC has planned renewable generation enabling expenditures all of which are to improve its Fort Frances MTS in order to modernize the station, and align its functionality with the government's smart grid development policy. As well, options for expansions are provided in its Plan, should a large scale generator want to connect to either its distribution system or transformer station. FFPC has indicated that its fully owned and operated transformer station Fort Frances MTS, is still robust and capable of offering full redundancy in the case where one of its two power transformers must be taken out of service.

The current situation in Northwestern Ontario where FFPC is situated, is that the there is very limited remaining transmission capacity to accommodate additional renewable energy generation at this time. Although there is a plan to expand the East-West Tie Line transmission link to the Northwest, providing the potential opportunity to accommodate new renewable energy generation in the region, the project is not anticipated to be in-service until 2017/2018. FFPC's Plan to modify its station protection and controls over a seven year period to provide additional distribution capacity, is consistent with the schedule of potential transmission improvements in the region.

Page 29 of their Plan describes FFPC's high level of coordination with other LDCs and entities in the Northwest. The OPA has also worked closely with FFPC to share system and station capacity information. Although a Regional Plan is not currently being developed as mentioned above, the OPA will continue to work closely with FFPC to determine how additional renewable energy generation facilities can be accommodated within FFPC's service territory as they become known.

The OPA appreciates the opportunity to comment on the information provided as part of the Fort Frances Power Corporation Distribution System Plan.

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Appendix 2: HONI Planning Status Letter

Hydro One Network Inc.
483 Bay Street
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www.HydroOne.com

Tel: (416) 345-5420
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ajay.garg@HydroOne.com

October 11, 2013

Mr. Joerg Ruppenstein
President & CEO
Fort Frances Power Corp.
P.O. Box 38
320 Portage Avenue
Fort Frances, Ontario, P9A 3P9

Dear Mr. Ruppenstein**:**

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) belongs to the Northwest Region, which is in Group 1. A map showing details with respect to the 21 Regions/Groups and list of LDCs in each Region is attached in Appendix A and B respectively.

As you may be aware, the Ontario Power Authority (OPA) has been conducting resource and transmission planning in the Northwest region in the past few years. They have identified need for transmission system reinforcements in the region such as the expansion of the East-West Tie and reinforcement of the transmission system north of Dryden. They have also identified options for augmenting the resources in the region following the closure of the coal-fired generating plants in the Northwest.

The report of the OEB's Planning Process Working Group has noted "that not all regions of Ontario are the same and that the Regional Planning processes will need to be flexible to accommodate those differences." The Northwest Region was identified to be "different from the other regions due to, among other reasons, the uncertainties related to changing resources and industrial loads, which may require consideration of a broader range of scenarios, expanded list of participants and means of grouping studies". At this time, Hydro One is in an early stage of discussions with the OPA with regard to the process to follow in carrying regional planning in the Northwest taking into account the OEB endorsed regional planning process, the changes in the Codes and licenses, the unique nature of the Northwest Region and the planning work that has already begun and in progress by the OPA in the region. We will endeavor to keep you informed and seek your input on this matter in the near future.

In the meantime, this letter is to confirm that the formal regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the Northwest Region affecting the Fort Frances Power Corp. I am expecting that the regional planning for the Northwest Region will be initiated in the 1st quarter of 2014. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

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The new planning process provides flexibility, during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One looks forward to working with Fort Frances Power Corp. in executing the new regional planning process.

If you have any further questions, please feel free to contact me.

Sincerely,

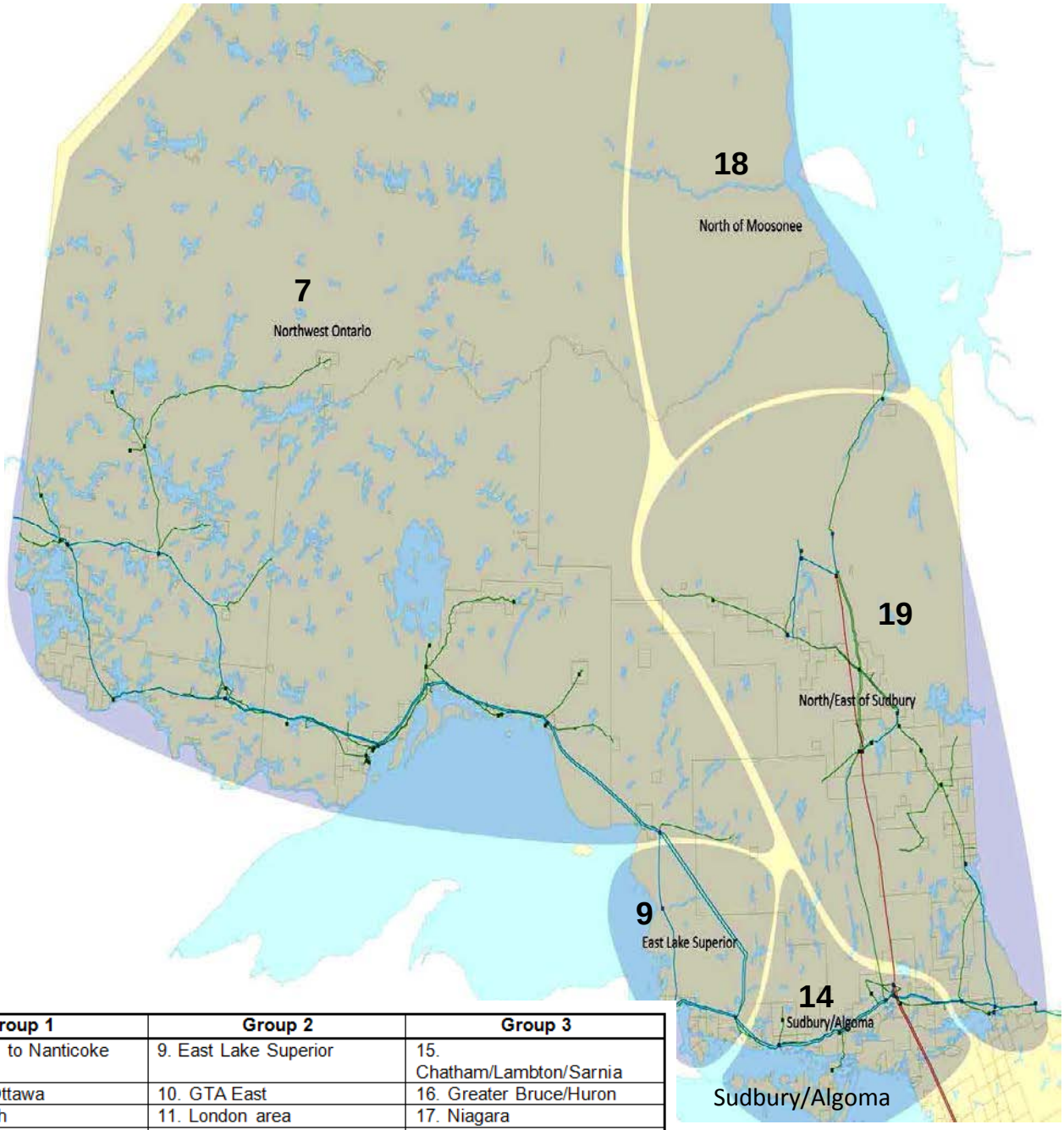


Ajay Garg, |Manager - Regional Planning and Transmission Load Connections|
Hydro One Networks Inc.

Cc:
Brad Colden, Manager – Customer Business Relations
Bob Chow, Director – Transmission Integration, OPA

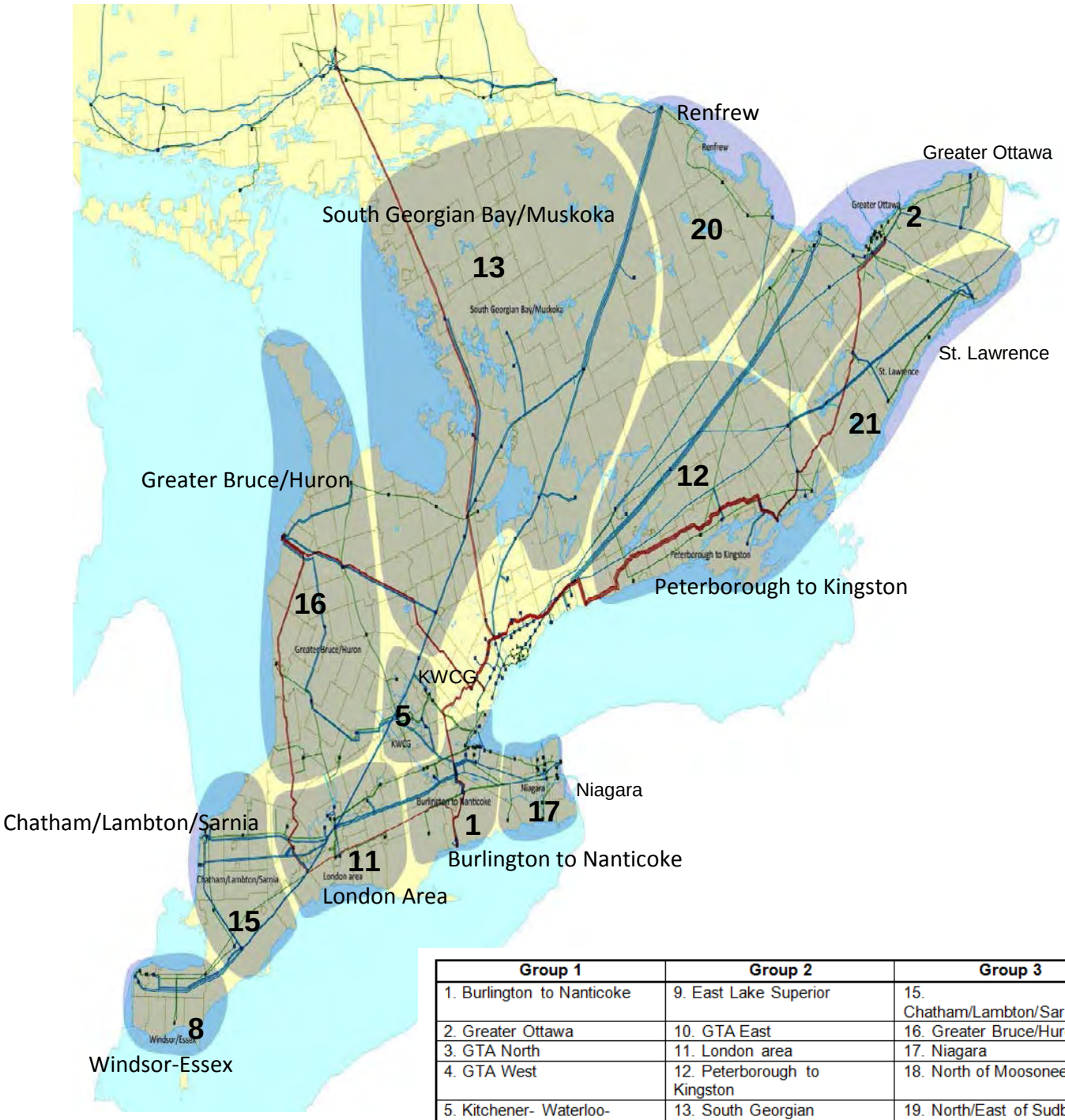
Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



Group 1	Group 2	Group 3
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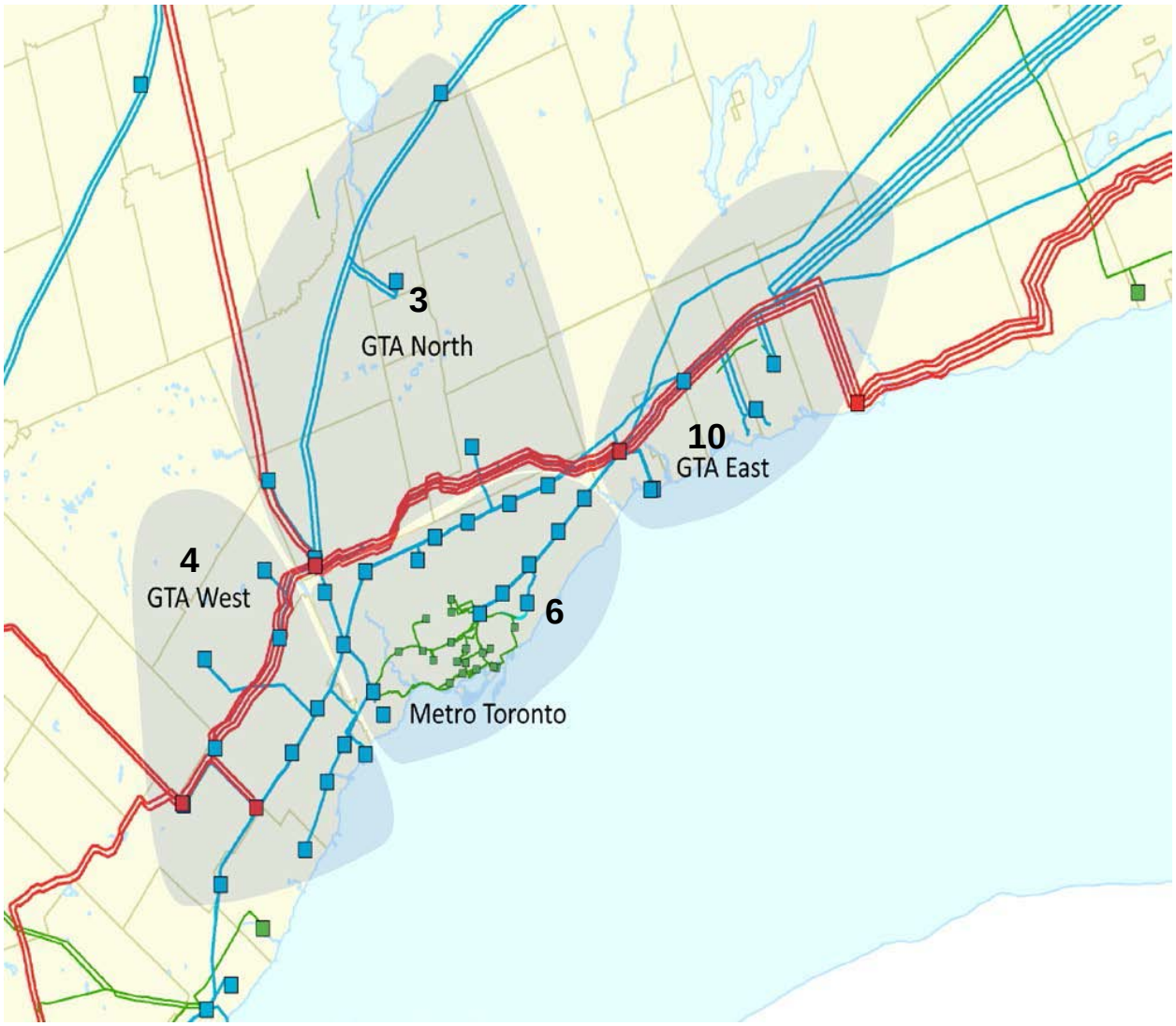
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
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5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines lnc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc*. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. *Changes to the May 17, 2013 OEB Planning Process Working Group Report.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Appendix 3: FFPC 2013 Customer Satisfaction Survey

Fort Frances Power Corporation

2013 Customer Satisfaction Survey

Filed with FFPC's 2014 Cost of Service Rate Application

Case Number EB-2013-0130

Submitted December 20, 2013

Management Response

Approach:

In July of 2013, FFPC conducted a customer satisfaction survey. All customers were given the opportunity to comment on FFPC's performance, to voice concerns and to indicate customer preferences with respect to present and future service offerings. FFPC was pleased with the results of the survey that was based on 345 out of a total possible 3733 responses. Customers were limited to one survey per customer. FFPC essentially heard from 9.2% of its entire customer base, enabling a high degree of confidence from a statistical view perspective.

Overall Customer Satisfaction:

Customers are overall very satisfied with the services provided by FFPC as indicated by the average score of 9.0 out of 10, where 10 is extremely satisfied. It is worth noting that only one customer response, out of 345 received, indicated a degree of dissatisfaction.

Reliability of Electricity Supplied:

Customers are overall very satisfied with the reliability of electricity supplied as indicated by an average score of 9.5 out of 10, where 10 is extremely satisfied. Management recommends continuing with its current practices towards maintaining electrical distribution system reliability.

Conservation Program Offerings:

Customers are moderately satisfied with the portfolio of conservation programs that are being offered, as indicated by an average score of 7.8 out of 10, where 10 is extremely satisfied. Conservation program offerings appear to be an opportunity for improvement. Management recommends that the feasibility of pursuing the expansion of CDM program offerings to target "Northern Needs" be investigated. Northern residents have a large potential for CDM program offering that address heat load requirements, their heating demand is considerably higher due to extremely cold winters and moderate summers. Northern consumers consume significantly more energy with respect to heating demand, as opposed to cooling requirements.

Communicating Planned Outages:

Customers are overall satisfied with how FFPC communicates planned outages as indicated by an average score of 8.8 out of 10, where 10 is extremely satisfied. Management recommends continuing with its current practice of announcing planned outages.

Satisfaction with Unplanned Outages:

Overall customers are very satisfied with how FFPC responds to power outages overall, with the amount of time taken to restore power and with FFPC's ability to respond to questions as indicated by average scores of 9.3, 9.1 and 8.0 respectively, where 10 is extremely satisfied. Customers are moderately satisfied with FFPC's communication of when power will be restored and with FFPC's communication of why an outage occurred, as indicated by average scores of 7.7 and 7.6 respectively, where 10 is extremely satisfied. Management recommends that although customers are moderately to very satisfied, an opportunity exists to improve customer communication.

Customer Experience with Power Outages:

The average FFPC customer reported outage length was 25 minutes (0.42 Hours). This statistic indicates exceptional performance when comparing the results to other publication such as the 2010 Pollara Report, which indicates an average outage length of 167.4 Minutes (2.79 Hours) reported by Ontarians. Management recommends that FFPC maintain its current practices towards electrical distribution system reliability.

Customer Perception of Causes of Power Outages:

FFPC finds that its customers are very aware as to the causes of power outages. More than half of the respondents indicated known causes of outages. Customers identified the following causes of outages: Storms or Adverse Weather, Planned Maintenance Work, Lightning, Equipment Failure, Animal Contact and Other (mostly car accidents). A cause to note is "Animal Contact". As a point of interest, around 2005 the number one cause of FFPC's outages was "Squirrel Contacts". FFPC has since implemented an animal contact guarding system on its transformers that has significantly reduced the number of related outages.

Impact of Outages to Customers:

Overall FFPC customers reported that in their experience power outages have had minimal impact on them. Only 1.2 % of respondents reported major concerns or inconveniences. The most common major concern was that sump pumps stopped working which could result in basement flooding, in the event that power outages coincide with heavy rain falls. It is worth noting that 42.6% of respondent indicated "None or No Impact". Most common Minimum Impact responses dealt with having to reset clocks or not being able watch TV. Most common Moderate concerns were related to not being able to cook meals, as well as not being able to open garage doors.

Customer Expectations - Unplanned Outages:

FFPC's customers reported expecting on average 2.9 power outages in a typical year, and to be without power for a total of 4.4 hours per year. Management notes that these customer expectations have been used to establish FFPC's customer driven reliability targets. In other words, FFPC is committed to achieving electrical distribution system reliability performance levels that meet or exceed customer expectations of experiencing fewer than 2.9 outages per year lasting no longer than 4.4 hours in total.

Customer Needs - Electric Vehicles:

FFPC's customers reported a relatively low desire of purchasing electric vehicles within the next five years. Only 2% of respondents indicated that they plan on purchasing an electric vehicle within the next five years. Fort Frances currently offers electric vehicle owners one formal fuelling station. Given the low level of interest in electric vehicles, FFPC does not plan to undertake related activities or expenditures during the period 2014 to 2018.

Customer Needs - Renewable Generation:

FFPC's customers reported a relatively low desire of installing small scale generation in their home within the next five years. Overall 3.8% of respondents indicated that they plan to install small scale generation in their home within the next five years. If 3.8% of customers were to install a medium sized microFIT installation of 5 kW each, FFPC would be connecting approximately 710 kW of generation capacity over the 2014 to 2018 planning period. This is approximately twice as much as the actual uptake that FFPC has experienced to date. FFPC management recommends proceeding with its planned Renewable Enabling Improvements at its transformer station, to alleviate current connection constraints, which are expected to be encountered in the near future. Management also recommends maintaining its current level of service offerings with respect to renewable generation over the next five years. For details regarding FFPC's ability to accommodate renewable generation please refer to Section 5.4.3 of FFPC's 2014 to 2018 DS Plan.

Customer Needs - Energy Storage Systems:

FFPC's customers report a relatively low desire of installing energy storage systems in their home within the next five years. Overall 2.9% of respondents indicated that they are planning to install an energy storage system in their home over the next five years. FFPC management does not foresee any major change in its business needs in order to be able to accommodate a low level of energy storage systems. Management recommends evaluating the technical requirements of accommodating energy storage systems, as to date FFPC does not have any practical experience with these systems.

Customer Needs - New Service Offerings:

FFPC asked its consumers whether or not they felt that several new service offerings are expenses that would be of value to their needs. FFPC was somewhat surprised with the results which state that:

1 - 56.2% of customers felt that accessing their consumption data and billing information through the internet is an expense that would not be of value to their needs. This compares to 34.5% of customers that felt the expense would be of value to their needs. The low level of support can be explained by the fact that a significant portion of FFPC's customer base is elderly, many whom do not know how to operate computers or many modern day electronics. FFPC acknowledges that the objective of enabling consumer access to consumption data in an electronic format is a regularity objective under the Renewed Regulatory Framework for Electricity and as such FFPC will proceed with its implementation.

2 - 56.2% of customers felt that the ability for FFPC to contact customers automatically, either by telephone or email, to alert them of events such as power outages is an expense that would be of value to their needs. This compares to 34.2% of customers who felt that the expense would not be of value to their needs.

3 - 46.1% of customers felt that offering a choice of receiving a paper bill or an electronic bill is an expense that would be of value to their needs. This compares to 45.2% of customers who felt that the expense would not be of value to their needs. FFPC management acknowledges that a large portion of FFPC's customer base is elderly, many of which do not know how to operate computers or modern day electronics. As such, FFPC will proceed with implementing electronic billing as an option, as well as continue to offer paper bills to accommodate customer needs.

4 - 50.7% felt that transitioning the billing process such that customers are billed on their true calendar month consumption would benefit them. This compares to 30.4% of customer who felt that this transition would not be of benefit to them.

Based on these results FFPC will implement the following new service offerings as part of its 2014 to 2018 five-year plan.

1 - Mass customer contact system (outage notification etc).
2 - Transition to true calendar monthly billing
3 - Offering Electronic Billing
4 - Online access to consumption and billing data.
5 - Maintain distribution system reliability and performance by replacing end of life assets, in accordance to FFPC's asset management and capital planning processes

Customer Identified Energy or Electricity Related Issues:

FFPC's customers are in tune with the electrical distribution sector and with current industry issues. The top three energy or electricity-related issues facing them and the community were identified to be:

1 - Cost of Electricity
2 - Losing the 1905 Historic Power Agreement
3 - LDC Amalgamations

FFPC Management is committed to minimizing consumer costs by exercising wise spending, as well as it is committed to up-keeping the 1905 Historic Power Agreement on behalf of its customers and community, for whom we exist. FFPC is also committed to operating as a viable and cost effective distributor.

Customer Suggestions for Improvements:

FFPC is very proud with the results of the question "Are there any specific things that FFPC could improve on to serve you better. 48.1% of all responses indicated "None" and 31.9% indicated "Don't Know". Of the relatively small proportion of suggested improvements representing a total of 13.6% of respondents, the most popular improvement suggestions were: 6.4% - Rate Reductions, 3.8% Access to Billing Data, 2.3% - transitioning to true calendar month billing, 2.0% Announcing Outages and 2.0% - Educating Consumers.

FFPC Management notes that it will be addressing many of the areas of improvement in the near future as per the following:

% Responses	Improvement	FFPC Course of Action
6.4%	Rate Reduction	Wise Spending through improved asset management and planning practices
3.8%	Access To Billing Data	FFPC will be implementing customer access to billing data
2.3%	Transition to Monthly Billing	FFPC will be transitioning to true calendar monthly billing
2.0%	Announcing Outages	FFPC will be investing in a mass customer contact technology
2.0%	Educating Consumers	FFPC will conduct consumer education campaigns
0.9%	Expand Business Scope	FFPC will evaluate the feasibility of this
0.9%	Length of Power Outages	FFPC is committed to minimizing power outages
0.6%	Other	N/A
0.3%	Arrears Payment Options	FFPC is committed to continually improving its customer care
0.3%	Budget Billing	FFPC is committed to continually improving its customer care
0.3%	Customer Care	FFPC is committed to continually improving its customer care
0.3%	Upgrade Infrastructure	FFPC is committed to up keeping its infrastructure

Consumer Education - Customer Topics of Interest:

FFPC is committed to improving its communication with customers, and a good illustration of this is FFPC's commitment to customer education campaigns. As per customer feedback FFPC will be launching consumer education campaigns beginning in 2014 that focus on consumer preference in the order of:

% Responses	Most Popular Topics of Interest
14.7%	Conservation
13.2%	Renewable Generation
12.7%	Smart Meters
11.1%	Smart Grid
9.8%	Understanding You Bill
8.7%	Demand Management
0.3%	Time-of-Use Rates
0.5%	Other

FFPC will be educating its customers utilizing Town Hall Meetings, trade shows and standard advertising outlets such as newspapers and bill inserts. FFPC is also planning on adding a new position of "Technical Customer Service Representative" to its organization. The position will primarily be responsible for engaging customers and to deliver customer preference related projects and services.

General Comments Received:

FFPC is also very proud of the general comments received. Almost half of customers who completed the survey provided general comments. Of the comments received, 71% were compliments towards FFPC such as:

> "Thank you for providing low cost electricity."
>
> "FFPC has always been very helpful at answering any questions in the past that I have had. They (the employees) have and do a great job. FFPC is an asset to this community."
>
> "I have lived at the same address for almost 51 years, and I cannot remember one negative problem with FFPC."
>
> "I think you are providing a quality, affordable product and service."

Summary:

FFPC is very pleased with the customer feedback received. FFPC will integrate the results obtained in this survey into its current and future planning activities, such as the Distribution System Plan. FFPC is committed to ensuring that its service offerings and priorities are aligned with the needs and priorities of its customers.

FFPC 2013 Customer Survey Score Card

		Scoring Legend			FFPC Score		
		Scoring Range From 1 to 10					
		Not At All Satisfied	Neither Satisfied or Dissatisfied	Extremely Satisfied	Average	Median	Mode
1	Overall, how satisfied are you with the services provided by the Fort Frances Power Corporation (FFPC)?	1	5	10	9.0	10.0	10.0
2	How satisfied are you with the reliability of the electricity supplied to you overall?	1	5	10	9.5	10.0	10.0
3	How satisfied are you with the portfolio of conservation programs that are currently offered to you?	1	5	10	7.8	10.0	10.0
4	How satisfied are you with how FFPC communicates planned outages to you?	1	5	10	8.8	10.0	10.0
5	Now thinking specifically about unplanned outages, how satisfied are you with FFPC:						
	a. Responding to power outages, overall?	1	5	10	9.3	10.0	10.0
	b. Amount of time taken to restore power?	1	5	10	9.1	10.0	10.0
	c. Ability to respond to questions?	1	5	10	8.0	10.0	10.0
	d. Communication when power will be restored?	1	5	10	7.7	9.5	10.0
	e. Communication why an outage occurred?	1	5	10	7.6	10.0	10.0

			FFPC Score		
6	Thinking of recent power outages that you have experienced:	Answer in Minutes	Average Minutes	Median Minutes	Mode Minutes
	a. On average, for how many minutes do power outages last?	X Minutes	25.0	15.0	30.0

b. To the best of your knowledge what caused these outages?

Perceived Cause of Recent Outages	
49.3%	% Don't Know
22.3%	% Storms / Adverse Weather
9.7%	% Planned Maintenance Work
6.8%	% Lightning
	% Equipment
4.7%	Failure
3.7%	% Animal Contact
3.4%	% Other
100.0%	Total

c. What impact, if any, did these power outages have on you or your family?

Most Common Answers:
Minimal: Reset Clocks, No TV
Moderate - Not Able to Cook, Garage Door Would not open
Major - Fear of sump pump not working

Impact of recent outages	
22.3%	% Don't Know
42.6%	% None
27.8%	% Minimal Inconvenience
6.1%	% Moderate Inconvenience
1.2%	% Major Inconvenience
100.0%	Total

		Scoring Legend		FFPC Score		
		Scoring Range from 1 to 10				
7	Thinking again about your experience with power outages, how concerned were you about the following:	Not At All Concerned	Extremely Concerned	Average	Median	Mode
	a. How long food would last?	1	10	3.9	1.0	1.0
	b. The temperature of your home?	1	10	4.3	2.0	1.0
	c. Ability to attend events?	1	10	2.4	1.0	1.0
	d. Childrens' and family's safety?	1	10	3.9	1.0	1.0
	e. Security of your home?	1	10	3.3	1.0	1.0

		Scoring Legend	FFPC Score		
		Number of Instances	Average	Median	Mode
8	How many unplanned power outages do you expect to happen at your home in a typical year?	X Unplanned Outages	2.9	2.0	2.0

		Scoring Legend	FFPC Score		
		Number of Hours	Average Hours	Median Hours	Mode Hours
9	How many hours in a year do you expect to be without electricity?	X Hours	4.4	3.0	1.0

		Scoring Legend	FFPC Score		
		Yes / No (or Don't Know)	% Yes	% No	% Don't Know
10	In the next five years, is your household planning to purchase an electric car?	Answer Yes or No	2.0%	84.3%	13.6%
11	In the next five years, is your household planning on installing a small scale renewable generation system (such as solar) for your home?	Answer Yes or No	3.8%	81.4%	14.8%
12	In the next five years, is your household planning on installing an energy storage system	Answer Yes or No	2.9%	82.9%	14.2%

13	FFPC is currently evaluating a solution that will allow our customers to access their electricity consumption data and billing information through the internet. Is this an expense that would be of value to your needs?	Answer Yes or No	34.5%	56.2%	9.3%
14	FFPC is evaluating investing in a technology that will give us the ability to contact you automatically by telephone or email, to alert you of important events such as power outages. Is this an expense that would be of value to your needs?	Answer Yes or No	56.2%	34.2%	9.6%
15	FFPC is evaluating offering customers a choice of receiving a paper bill or an electronic bill via email or through web access. Is this an expense that would be of value to your needs?	Answer Yes or No	46.1%	45.2%	8.7%
16	FFPC is evaluating changing its billing process such that customers will be billed on their true monthly consumption (from the first day of the month to the last day of the month). Would this transition be of benefit to you?	Answer Yes or No	50.7%	30.4%	18.8%

17 What would you say is the most important energy or electricity-related issue facing the community of Fort Frances today?

Most Important Issues Identified by Customers

34.8%	*% Don't Know*
32.2%	% Cost of Electricity
10.1%	% Losing Historic Power Agreement
	% LDC
8.2%	Amalgamation
2.9%	% Conservation
2.9%	% Other
2.7%	% Reliability
2.4%	% Renewable Generation
	% Time-of-Use
2.4%	Rates
1.3%	% Upgrading Infrastructure
100.0%	Total

18	Are there any specific things that FFPC could improve on to serve you better?	**Most Common Suggestions For Improvements**	
		31.9%	*% Don't Know*
		48.1%	% None
		6.4%	% Rate Reduction
		3.8%	% Access To Billing Data
		2.3%	% Transition to Monthly Billing
		2.0%	% Announcing Outages
		2.0%	% Educating Consumers
		0.9%	% Expand Business Scope
		0.9%	% Length of Power Outages
		0.6%	% Other
		0.3%	% Arrears Payment Options
		0.3%	% Budget Billing
		0.3%	% Customer Care
		0.3%	% Upgrade Infrastructure
		100.0%	Total
19	FFPC is looking to launch several consumer education campaigns, are there any specific topics that you would like to know more about such as Conservation, Demand Management, Smart Grid, Renewable Generation, Smart Meter, Understanding Your bill etc?	**Most Requested Topics for Consumer Education**	
		28.9%	% None
		14.7%	% Conservation
		13.2%	% Renewable Generation
		12.7%	% Smart Meters
		11.1%	% Smart Grid
		9.8%	% Understanding Your Bill
		8.7%	% Demand Management
		0.5%	% Other
		0.3%	% TOU Rates
		100.0%	Total
20	We would appreciate any general comments:	**Most Common Comments Received**	

General Comment	
1.7%	% General Comment (Not FFPC Specific)
0.9%	% Comment - Access billing data / online Billing
2.6%	
Complaints	
0.3%	% Complaint - Survey is money not well spent
0.3%	% Complaint - Deposit policy
1.4%	% Complaint - Time-of-Use Rates
0.6%	% Complaint - When will DRC be paid off?
2.6%	
Compliments to FFPC	
0.9%	% Compliment - Appreciated survey
0.3%	% Compliment - Billing Information
34.5%	% Compliment - Good Job, Great Utility, etc.
35.7%	
Voicing Concerns	
0.3%	% Concern - Availability of Future Supply
1.2%	% Concern - Elderly having to use computers
1.2%	% Concern - LDC Amalgamating
0.9%	% Concern - Losing Historic Power Agreement
3.5%	
No Response Provided	
51.6%	% None
51.6%	
Customer Requests	
0.3%	% Request - Keep rates low
0.3%	% Request - Offer more CDM incentives

0.3%	% Request - Reduce delivery charge
1.4%	% Request for information
2.3%	

Customer Suggestions For Improvements

0.3%	% Suggested Improvement - Customer Relations
0.3%	% Suggested Improvement - Length of Outages
0.3%	% Suggested Improvement - Survey Access
0.3%	% Suggested Improvement - Survey Format
0.6%	% Suggested Improvement - Move to true monthly billing
1.7%	

100.0%	Total

Appendix 4: Maintenance Inspection Program

FFPC

FORT FRANCES POWER CORPORATION

Maintenance Inspection Program

In Accordance to the Requirements of:

Ontario Regulation 22/04 Sections 4 & 5

"Safety Standards / When Safety Standards Met"

And

Ontario Energy Board

Electrical Distribution System Code Appendix C

"Minimum Inspection Requirements"

Rev. 3, November 2012

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Foreword:

In response to the 2007 ESA Regulation 22/04 Compliance Audit, the Fort Frances Power Corporation has taken initiative to develop a formal policy and protocol to govern the maintenance and inspection of overhead, underground and transformer station facilities.

Purpose:

The intent of this document is to establish the processes and guidelines to meet the requirements of Ontario Regulation 22/04 Section 4, "Safety Standards" and section 5, "When Safety Standards met" and of the Ontario Energy Board's Distribution System Code Appendix C, "Minimum Inspection Requirements". In addition, this document describes the formal process and protocol that governs the maintenance for overhead, underground and transformer station maintenance.

Process Summary:

The Fort Frances Power Corporation performs routine inspections on all of its overhead, underground and transformer station facilities, to ensure that deficiencies are identified and corrected on a timely basis, to minimize the probability of exposure to electrical hazards. The inspection system is broken into three components; inspection of overhead systems, inspection of underground systems and inspection of transformer station. All three components are subjected to "Tier 1" inspections that are performed at least quarterly for overhead and underground distribution plant and monthly on transformer station plant. Tier 1 line patrol inspections utilize generic inspection forms that do not reference FFPC's itemized assets that are now available through FFPC's GIS system.

Over the last several years FFPC has implemented "Tier 2" Inspections that are inspections performed at the major distribution asset level. FFPC has itemized its major overhead and underground distributions assets and developed asset specific inspection logs. FFPC will perform asset specific "Tier 2" at a minimum inspection interval of three years. The three year inspection cycle is in accordance with the "Minimum Inspection Requirements" a set out in the Ontario Energy Board's Distribution System Code (DSC) Appendix C.

Section 1: Overhead Distribution System

Regulation 22/04 Requirements and FFPC Policy:

All overhead distribution lines, including secondary distribution lines, shall meet the following safety standards:

1. Operating electrical equipment shall be maintained in proper operating condition.

2. Adequate space shall be provided around electrical equipment for proper operation and maintenance.
3. Energized conductors and live parts shall be barriered such that vegetation, equipment or unauthorized persons do not come in contact with them or draw arcs under reasonably foreseeable circumstances.
4. Metal parts of the installation that are not intended to be energized and that are accessible to unauthorized persons shall be effectively grounded.
5. Structures supporting energized conductors and live parts shall have sufficient strength to withstand the loads imposed on the structure by electrical equipment and weather loadings. O. Reg. 22/04, s. 4 (4).

Overhead Inspection Process:

Inspection of the overhead distribution system is performed at a minimum quarterly basis utilizing FFPC's "Tier 1" inspection forms. The following list of observations / tests is performed to assess components to either be Acceptable or Not Acceptable. Not acceptable items are documented and tracked on a maintenance summary backlog and are repaired as soon as practically possible depending on the urgency of the deficiency. Refer to Appendix B for a copy of the Tier 1 Overhead Distribution System Inspection Form

Tier 1 Inspections - Patrol Inspections:

Transformers:

- Tank Corrosion/Rust, Paint Condition
- Tank Leaking Oil
- Exterior Damage
- Contamination/Discolouration of Bushings
- Flashed or Cracked Insulators
- Loose Cable Connections
- Accessibility Compromised

Switches & Protective Devices:

- Bent, Broken Bushings & Cutouts
- Damaged Lightning Arrestors
- Ground Wires on Arrestors Unattached
- Damaged Instrument Transformers

Conductors & Cables:

- Low Conductor Clearance
- Broken or Frayed Conductor Strands
- Exposed Broken Ground Conductor
- Excessive or Inadequate Conductor Sag
- Bared Insulation on Secondary Conductor

Poles & Supports:

- Leaning, Cracked or Broken Poles
- Excessive Surface Wear or Scaling
- Indications of Burning
- Woodpecker or Insect Damage
- Bird Nests on Poles
- Loose or Broken Cross Arms
- Loose or Broken Brackets
- Loose or Unattached Guy Wires or Stubs
- Guy Strain Insulators Pulled Apart or Broken
- Guy Guards Out of Position or Missing
- Guy Anchors Exposed
- Grading Changes or Washouts

Pole Hardware & Attachments:

- Loose or Missing Hardware
- Insulators Unattached From Brackets
- Conductor Unattached From Insulators
- Riser Pole Hardware Damage
- Dip Pole Hardware Damage
- Insulators Flashed Over or Contaminated
- Tie Wires Unravelled
- Ground Wire Broken or Removed
- Ground Wire Guards Broken or Removed
- Missing Switch, Riser or Dip Pole ID Tag

Other Equipment Installations:

- Telecommunications Attachments
- Cable TV Attachments
- Hydro One Attachments
- Accessibility Compromised

Vegetation & Right of Way:

- Leaning or Broken "Danger" Trees
- Trees, Vines or Brush Growth Interference

Tier 2 Inspections - Detailed Asset Inspections:

FFPC has invested significant resources towards the development of a Geographic Information (GIS) system. The GIS system contains a detailed listing of FFPC's major overhead and underground distribution system components including poles, transformers, primary conductor runs and conductor sizes. FFPC is currently

creating “itemized” inspection logs at the component level (ie. for overhead plant listing every pole) that are intended to be completed at a minimum three year interval. FFPC refers to these inspections as “Tier 2” Inspections and sample inspection forms are located in Appendix F.

Tier 2 Overhead Plant Inspections:

Perform inspection of all poles and associated pole hardware rating each inspection category "S-Satisfactory" or "U-Unsatisfactory." Not Applicable categories may be left blank of denoted "N/A'. Examples of deficiencies include:

Inspection Categories:

Pole Hammer Test

- Structural integrity of pole tested via hammer test

Pole Condition Assessment

- Leaning, Cracked or Broken Poles
- Excessive Surface Wear or Scaling
- Indications of Burning
- Woodpecker or Insect Damage
- Bird Nests on Poles

Anchors & Guying

- Loose or Unattached Guy Wires or Stubs
- Guy Strain Insulators Pulled Apart or Broken
- Guy Guards Out of Position or Missing
- Guy Anchors Exposed
- Grading Changes or Washouts

Primary / Secondary Conductor

- Low Conductor Clearance
- Broken or Frayed Conductor Strands
- Exposed Broken Ground Conductor
- Excessive or Inadequate Conductor Sag
- Bared Insulation on Secondary Conductor
- Conductor Unattached From Insulators
- Tie Wires Unravelled
- Ground Wire Broken or Removed
- Ground Wire Guards Broken or Removed

Pole-Top Assembly

- Bent, Broken Bushings & Cutouts
- Damaged Lightning Arrestors
- Ground Wires on Arrestors Unattached
- Damaged Instrument Transformers
- Loose or Broken Cross Arms
- Loose or Broken Brackets
- Loose or Missing Hardware

Insulators Unattached From Brackets

- Riser Pole Hardware Damage
- Dip Pole Hardware Damage
- Missing Switch, Riser or Dip Pole ID Tag
- Insulators Flashed Over or Contaminated

Transformers

- Tank Corrosion/Rust, Paint Condition
- Tank Leaking Oil
- Exterior Damage
- Contamination/Discolouration of Bushings
- Flashed or Cracked Insulators
- Loose Cable Connections
- Accessibility Compromised

Third Party Attachments

- Telecommunications Attachments
- Cable TV Attachments
- Hydro One Attachments
- Accessibility Compromised

Vegetation

- Leaning or Broken "Danger" Trees
- Trees, Vines or Brush Growth Interference

Deficiency Criticality Rating:

Upon the discovery of a deficiency, the deficiency will be prioritized as per the following (note that priority 1 - Immediate Attention deficiencies are acted upon immediately and do not require the issuance of a Work Oder).

1. Immediate Attention - Hazardous condition exists that requires immediate attention
2. Immediate Analysis - Requires immediate analysis to determine severity of condition
3. Priority Schedule - Requires prompt planned attention but no immediate hazard exists
4. Regularly Schedule - Requires planned attention but no immediate hazard exists
5. Regular Inspection Cycle - Potential deficiency exists, to be re-evaluated during next regular inspection cycle

Completion of Inspection Phase

Once all assets have been inspected according to the asset listing, the inspectors involved in performing the inspection signoff on the inspection process so that formal processing of deficiencies can begin.

Processing of Deficiencies

Upon completion of the inspection cycle, a review of findings is conducted and deficiencies are processed for appropriate corrective actions such as being to a maintenance work order or to future capital plans.

Review of Status of Deficiencies

A periodic review of identified deficiencies is conducted to ensure that all identified deficiencies are processed.

Section 2: Underground Distribution System

Regulation 22/04 Requirements and FFPC Policy:

All underground distribution lines, including secondary distribution lines, shall meet the following safety standards:

1. Operating electrical equipment shall be maintained in proper operating condition.
2. Adequate space shall be provided around electrical equipment for proper operation and maintenance.
3. Energized conductors and live parts shall be barriered such that equipment or unauthorized persons do not come into contact with them or draw arcs under reasonably foreseeable circumstances.
4. Metal parts of the installation that are not intended to be energized and that are accessible to unauthorized persons shall be effectively grounded.
5. Parts of the distribution system in proximity to the inside walls of a swimming pool shall be installed in such a way as to minimize the possibility of voltage gradients in the swimming pool.
6. Parts of a distribution system in proximity to propane tanks and natural gas pipelines shall be installed in such a way as to minimize the possibility of explosions under normal circumstances and operating conditions. O. Reg. 22/04, s. 4 (5).

Underground Inspection Process:

Inspection of the underground distribution system is performed at a minimum quarterly basis utilizing FFPC's "Tier 1" inspection forms. The following list of observations / tests is performed to assess components to either be Acceptable or Not Acceptable. Not acceptable items are documented and tracked on a maintenance summary backlog and are repaired as soon as practically possible depending on the urgency of the deficiency. Refer to Appendix B for a copy of the Tier 1 Underground Distribution System Inspection Form.

Tier 1 Inspections - Patrol Inspections:

Pad-mount Transformers & Enclosures

- Corrosion/Rust, Paint Condition
- Leaking Oil

- Lid or Cabinet Damage
- Missing Bolts
- Security Lock Damage
- Grade Changes
- Access Changes

Switching & Protective Devices:

- Structural Condition of Enclosure
- Security Condition of Enclosure
- Missing Switch ID Tag

Conductors & Cables:

- Exposed Cables
- Grade Changes Bringing Cable to Surface

Tier 2 Inspections - Detailed Asset Inspections:

FFPC has invested significant resources towards the development of a Geographic Information (GIS) system. The GIS system contains a detailed listing of FFPC's major overhead and underground distribution system components including poles, transformers and conductor sizes. FFPC is currently creating "itemized" inspection logs at the component level (a listing of all pad mounted transformers to perform enclosure integrity inspections) that are intended to be completed at a minimum three year interval. For a sample itemized underground inspection sheet, refer to Appendix G.

Tier 2 Overhead Plant Inspections:

Perform inspection of all pad-mounted transformer and associated equipment, rating each inspection category "S-Satisfactory" or "U-Unsatisfactory." Not Applicable categories may be left blank of denoted "N/A'. Examples of deficiencies include:

Inspection Categories:

Lock Integrity

- Security Lock Damaged / Not Operational

Enclosure/Exterior Inspection

- Corrosion/Rust, Paint Condition
- Lid or Cabinet Damage
- Doors do not open
- Missing Bolts
- Exposed Cables
- Nomenclature / Danger Signage

Internal Visual Inspection

- Leaking Oil
- Animal Intrusion
- Cable Damage / Degradation
- Connector Damage / Degradation
- Cracked Bushing

General / Other Observations

- Grade Concerns / Tilting
- Accessibility / Obstructions / Plant Interference
- Grade Changes Bringing Cable to Surface
- Bollards
- Concrete Pad

Snow Poles

FFPC also uses the inspection log to track the annual installation and removal of snow poles. FFPC installs snow poles on all pad-mounted transformers that are in proximity to vehicular traffic such that transformer enclosures can be easily identified in deep snow.

Assessing Criticality of Deficiency:

Upon the discovery of a deficiency, the deficiency will be prioritized as per the following (note that priority 1 - "Immediate Attention" deficiencies are acted upon immediately and do not require the issuance of a Work Oder).

1. Immediate Attention - Hazardous condition exists that requires immediate attention
2. Immediate Analysis - Requires immediate analysis to determine severity of condition
3. Priority Schedule - Requires prompt planned attention but no immediate hazard exists
4. Regularly Schedule - Requires planned attention but no immediate hazard exists
5. Regular Inspection Cycle - Potential deficiency exists, to be re-evaluated during next regular inspection cycle

Processing of Deficiencies

Upon completion of the inspection cycle, a review of findings is conducted and deficiencies are processed for appropriate corrective actions such as being assigned to a maintenance work order or to future capital plans.

Review of Status of Deficiencies

A periodic review of identified deficiencies is conducted to ensure that all identified deficiencies are processed.

Section 3: Transformer Station

Regulation 22/04 Requirements and FFPC Policy:

Transformer stations shall meet the following safety standards:

1. Operating electrical equipment shall be maintained in proper operating condition.
2. Adequate space shall be provided around electrical equipment for proper operation and maintenance.
3. Metal parts of the installation that are not intended to be energized and that are accessible to unauthorized persons shall be effectively grounded.
4. Energized conductors and live parts shall be barriered such that equipment or unauthorized persons do not contact them or draw arcs under reasonably foreseeable circumstances.
5. Structures supporting energized conductors and live parts shall have sufficient strength to withstand the loads imposed on the structure by equipment and weather loadings. O. Reg. 22/04, s. 4 (6).

Transformer Station Inspection Process:

Inspection of the transformer station is performed on a monthly basis, as well as on an annual basis with the annual inspection having different inspection criteria. The following list of observations / tests are performed to assess components to either be Acceptable or Not Acceptable. Not acceptable items are documented and tracked on a maintenance summary backlog and are repaired as soon as practically possible depending on the urgency of the deficiency.

Outside Yard:

- Condition of Driveway & Surrounding Yard
- Condition of Station Fence & Gates
- Condition of Signage
- Condition of Security Locks
- Grading Changes or Washouts Along Fence
- Operation of Yard Lights
- Condition of Yard Housekeeping
- Vegetation Growth Inside Fence Area

Exterior of Buildings:

- Condition of Exterior Walls & Roofs
- Condition of Exterior Doors & Security Locks
- Operation of Exterior Lights

Tower Structure:

- Leaning, Cracked or Bent Components
- Loose Bolts or Fasteners

- Exterior Corrosion/Rust
- Exterior Damage
- Condition of Insulators
- Condition of Energizing Blades

Transformers:

- Leaking Oil
- Paint Condition
- Exterior Corrosion/Rust
- Exterior Damage
- Operation of Fans
- Condition of Bushings & Arrestors
- Condition of Tap Changer Cabinet
- Operation of Tap Changer
- Operation of Tap Changer Heater
- Oil Samples Taken & Sent for Analysis

Oil Filled Circuit Breakers:

- Operation of Heaters
- Oil Samples Taken & Sent for Analysis

Transformer DC Battery Bank:

- Leaking Fluid
- Condition of Jumpers & Plates
- Condition of Cabinet
- Test Individual Battery Cell Voltages (Quarterly)
- Operation of Charger
- Calibrate Float
- Equalize Voltage
- Charge Batteries
- End-of-Life Battery Test (5years)

Relays:

- Status of Reclosures & Flags
- Operation of Relays (Breakers in Test Mode)
- Test & Re-Calibrate (3 years)

Interior of Buildings:

- Condition of Walls, Floors & Ceilings
- Operation of Lights
- Operation of DC Lights
- Operation of Heating & HVAC System
- Operation of Station Telephone
- Condition of Eyewash Station

- Condition of First Aid Kit
- Condition of Housekeeping

Switchgear:

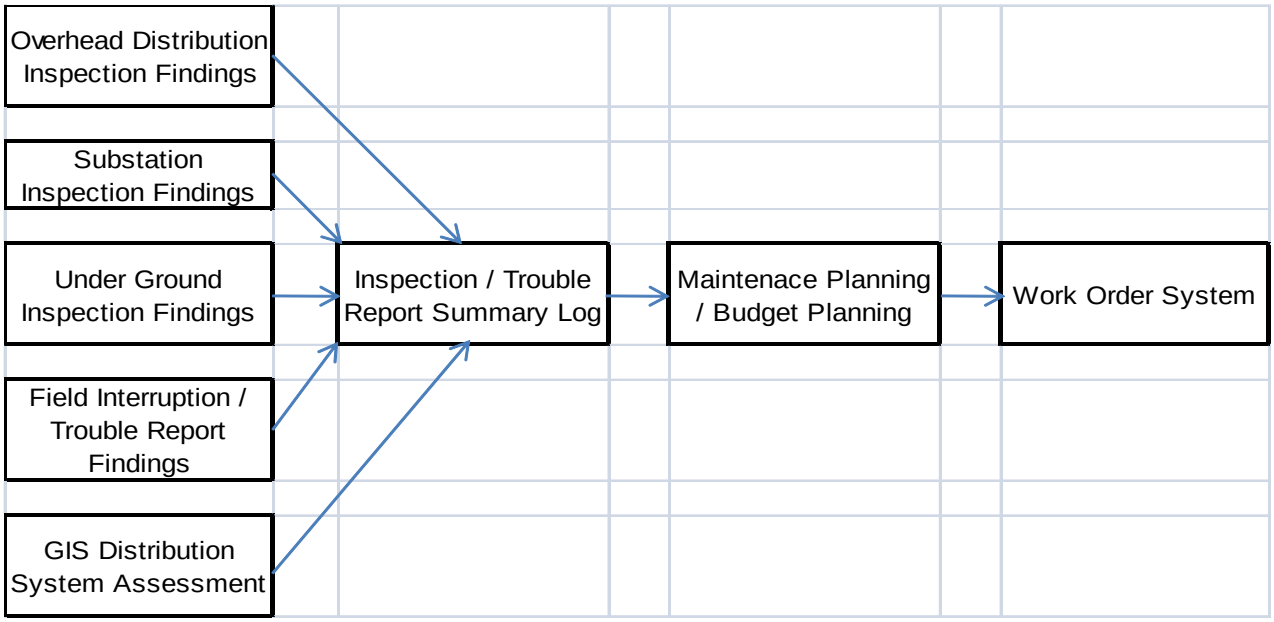
- Condition of Station Arrestors (Back Cabinet)
- Operation of Breakers (2 years)
- Cleaning of Breakers (2 years)

Third Party Inspection and Maintenance of FFPC Substation:

FFPC has retained third party services to provide annual condition testing and inspections of key substation components and to perform any necessary major repairs. All major station components are condition tested on a three year cycle. Inspections are performed on all high/medium voltage circuit breakers, station transformers (including on-load tap changers and lightning arresters), DC power systems, and all station protective relaying. In addition, oil testing and condition analysis is performed on station transformers and high voltage oil filled circuit breakers annually.

Maintenance Planning Process:

The Fort Frances Power Corporation aims to perform maintenance on its plant in a proactive manner, utilizing the inspection process as well as information gathered from Trouble, Outage Reports and its GIS system to develop maintenance action items. All "Not Acceptable" maintenance items, as well as Outage Causes, are tracked on a maintenance log to ensure that all items are repaired in a timely manner as well as assisting in future maintenance planning to improve the system performance, reliability and safety. An item will remain on the maintenance log until the item is marked as complete and no further action is required. The document / information flow is as follows.


Overhead Distribution Inspection Findings
Substation Inspection Findings
Under Ground Inspection Findings
Field Interruption / Trouble Report Findings
GIS Distribution System Assessment
Inspection / Trouble Report Summary Log
Maintenace Planning / Budget Planning
Work Order System

Appendix A:

Regulation 22/04 Definitions as per Technical Guidelines

Definitions

1.3.1 "ancillary equipment" means electrical installations (not located in buildings, or rooms in buildings, used as offices, washrooms, cafeterias, warehouses, garages, machine shops and recreational facilities) that are operating at 750 Volts or below to support but are not a direct part of a *distribution system* such as sump pumps, SCADA equipment, strip heating, etc.;

1.3.2 "approved equipment" means equipment that meet rule 2-024 of the Electrical Safety Code or that has been purchased, tested and inspected in accordance with industry standards, or equipment specification, or *Good Utility Practice* and procedures of the distributor and an assurance of safety of the equipment equivalent
to rule 2-024 of the Electrical Safety Code is provided; 1.3.3 "Authority" means the Electrical Safety Authority;

1.3.4 "authorized person" means a *competent person* authorized by a distributor to have access to areas containing, or structures supporting, energized apparatus or conductors. O. Reg.22/04;

1.3.5 "barriered" means separated by clearances, burial, separations, spacings, insulation, fences, railings, enclosures, structures and other physical barriers, signage, markers or any combination of the above (Reg.22/04);

1.3.6 "Certificate" means a certificate issued by a *professional engineer*, ESA or a *qualified person* identified in the distributor's construction verification program, that the construction meets the safety standards set out in Section 4 of the Regulation;

1.3.7 "certificate of approval" means the certificate issued by a professional engineer or ESA confirming that a plan or Standard Design meets the safety standards set out in section 4 of the Regulation and provided to the distributor;

1.3.8 "certification organization" means an organization accredited by the Standards Council of Canada;

1.3.9 "Certified Test Report" means a report that contains sufficient information to allow the distributor's competent person to approve the electrical equipment. The report shall provide sufficient information to ensure the equipment meets or exceeds the applicable industry standard or distributor developed equipment specification. A Certified Test Report must be signed by a P.Eng or an Engineer where the licensure's obligation to public safety of the home jurisdiction are substantially equivalent to those required by Ontario.

1.3.10 "competent person" means a person who,

(a) is qualified because of knowledge, training and experience,
(i) to perform specific work, or
(ii) to organize work and its performance,

(b) has knowledge of any potential or actual danger to health or safety in the workplace in relation to the work, and

(c) Is familiar with section 113 of the Act and the regulations made under it, and with the *Occupational Health and Safety Act* and the regulations made under that Act, that apply to the work. O. Reg.22/04;

1.3.11 “construction verification” means the inspection, approval and documentation of any new construction or repairs to *distribution systems* including replacements of part or portion of a distribution system, *like-for-like replacements,* and *legacy construction* replacement with respect to the safety standards set out in Section 4 of the Regulation;

1.3.12 “contractor” means any person who performs work on electrical equipment or an electrical installation. O. Reg.22/04;

1.3.13 “disconnecting means” means a device, group of devices or other means whereby the conductors of a circuit can be disconnected from their source of supply. O. Reg.22/04;

1.3.14 “distribution line” or “line” means an electricity distribution line, transformers, plant or equipment used for conveying electricity at voltages of 50,000 volts or less (Reg.22/04);

1.3.15 “distribution station” means an enclosed assemblage of equipment, including but not limited to switches, circuit breakers, buses and transformers, through which electrical energy is passed for the purpose of transforming one primary voltage to another primary voltage. O. Reg.22/04;

1.3.16 “distribution system” means a system for distributing electricity, and includes any structures equipment or other things used by a *distributor* for that purpose;

1.3.17 “distributor” means a person who owns or operates a *distribution system* in the service territory defined in the electricity distribution license issued by the Ontario Energy Board (OEB);

1.3.18 “effectively grounded” means permanently connected to earth through a ground connection of sufficiently low impedance and having sufficient current-carrying capacity to prevent the building up of voltages that may result in undue hazard to persons. O. Reg.22/04;

1.3.19 "electrical installation" means the installation, repair, replacement, alteration or extension of any wiring or electrical equipment that forms part of a distribution system (Reg.22/04); 1.3.20 “ESC” means the Electrical Safety Code referred to in Ontario Regulation 164/99;

1.3.21 "equipment" or “electrical equipment” means any apparatus, device or material used for the distribution of electricity, including materials that are non-electric in origin *(refer to the Regulation for the complete definition of “electrical equipment”*(Reg.22/04);

1.3.22 “field evaluation agency” means an organization accredited by the Standards Council of Canada and recognized by the Electrical Safety Authority (ESA) as being qualified to carry out a safety evaluation of electrical equipment that is limited in scope to essential safety considerations;

1.3.23 “Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be

acceptable practices, methods, or acts generally accepted in North America (DSC);

1.3.24 "hazard" means a potential for injury to a person or property;

1.3.25 "legacy construction" means existing construction built in accordance with *Good Utility Practice*, that does not meet current Standard Designs;

1.3.26 "like-for-like replacement" means the replacement of one piece of electrical equipment (one assembly) under all conditions, or a part or portion of a line under emergency conditions, on an existing distribution system that maintains as a minimum the characteristics and functionalities of the original installation;

1.3.27 "line upgrade" means the replacement or significant improvement of an existing *distribution line*;

1.3.28 "live" means electrically connected to a source of voltage difference or electrically charged so as to have a voltage different from that of the earth O. Reg.22/04;

1.3.29 "no undue hazard" for the purpose of approving equipment for use in the distribution system where indicated in this Guideline means that:

- energized parts of the equipment are insulated or *barriered*,
- the equipment has sufficient mechanical strength to withstand the loads imposed on it by the intended application in the distribution system,
- the equipment has grounding provision so that it can be *effectively grounded* where required,
- the equipment design and construction has no unprotected sharp edges, or dangerous moving parts,
- the equipment electrical characteristics and protection minimize the possibility of excessive temperature, fire or explosion under expected operation conditions;

1.3.30 "no undue hazard" for the purpose of *construction verification* of an *electrical installation* where indicated in this Guideline means that:

- metal parts that are not intended to be energized and that are accessible to unauthorized persons are adequately grounded,
- *live* parts are adequately insulated or *barriered*,
- the installation meets the minimum CSA clearances from buildings, signs and ground or barriers are installed to protect,
- the structure has adequate strength where adequate means in accordance with *Good Utility Practice*;

1.3.31 "ownership demarcation point" means the point,

(a) at which the distributor's ownership of a distribution system, including connection assets, ends at the customer, and

(b) that is not located beyond,

i. the first set of terminals located on or in any building,or

ii. an electrical room or *vault* in a building where the electrical room or *vault* is of tamperproof construction, bears a sign to indicate that it is an electrical room or *vault* and is accessible only to *authorized persons* (Reg.22/04);

1.3.32 “plan” means the drawings and instructions that are prepared for the construction of new or modified *distribution system* that have been reviewed and approved by a *professional engineer* or ESA;

1.3.33 “primary distribution line” means a distribution line conveying electricity at more than 750 volts but not more than 50,000 volts phase to phase; O. Reg.22/04

1.3.34 “professional engineer” means a person who holds a license or temporary license under the Professional Engineers Act (Reg. 22/04);

1.3.35 “putting a system into use” means making an *electrical installation* forming part of the electrical *distribution system* available for service;

1.3.36 “qualified person” means a person identified in a *construction verification* program developed by the distributor and approved by ESA for the purpose of inspection and approval of construction;

1.3.37 “record of inspection” means a record prepared by a *professional engineer*, ESA, or a *qualified person* identified in the distributor’s *construction verification* program, detailing the inspection of a constructed or repaired portion of an electrical distribution system with respect to the safety standards set out in section 4 of the Regulation;

1.3.38 “Regulation” means the Ontario Regulation 22/04 – Electrical Distribution Safety;

1.3.39 “safety standards” means the safety standards set out in section 4 of the Regulation;

1.3.40 “secondary distribution line” means an electricity distribution line conveying electricity at 750 volts or less phase to phase. O. Reg.22/04;

1.3.41 “Standard Designs” means the standards such as standard design drawings, standard design specifications, technical specifications, and construction standards that have been reviewed and approved by a *professional engineer* or ESA for use by a *distributor* and that the *distributor* uses on an ongoing basis for the construction, operation, and maintenance of its distribution system;

1.3.42 “Utility Advisory Council (UAC)” means an advisory body formed to provide advice to ESA specific to the Electrical Distribution Safety Regulation governing the distribution of electricity in Ontario;

1.3.43 “vault” means an isolated enclosure, either above or below ground, with fire-resistant walls, ceilings and floors in which transformers and other *electrical equipment* are housed. O. Reg. 22/04, s. 1.

1.3.44 “work instruction” means the assembly of *Standard Designs* into drawings and instructions prepared by a *competent person* in accordance with the distributor’s job planning process used for the installation of new or modified *electrical equipment* that forms part of a *distribution system*.

Appendix B:

Tier 1 Overhead / Underground Distribution System Inspection Form

Fort Frances Power Corporation - Distribution System Field Inspections

Month:

	Acceptable	Problem / Condition Description	Location / Work Order	Date Corrected
A. Overhead System				
1) Transformers:				
Tank Corrosion/Rust, Paint Condition				
Tank Leaking Oil				
Exterior Damage				
Contamination/Discolouration of Bushings				
Flashed or Cracked Insulators				
Loose Cable Connections				
Accessibility Compromised				
2) Switching & Protective Devices:				
Bent, Broken Bushings & Cutouts				
Damaged Lightning Arrestors				
Ground Wires on Arrestors Unattached				
Damaged Instrument Transformers				
3) Conductors & Cables:				
Low Conductor Clearance				
Broken or Frayed Conductor Strands				
Exposed Broken Ground Conductor				
Excessive or Inadequate Conductor Sag				
Bared Insulation on Secondary Conductor				

	Acceptable	Problem / Condition Description	Location / Work Order	Date Corrected
4) Poles & Supports:				
Leaning, Cracked or Broken Poles				
Excessive Surface Wear or Scaling				
Indications of Burning				
Woodpecker or Insect Damage				
Bird Nests on Poles				
Loose or Broken Cross Arms				
Loose or Broken Brackets				
Loose or Unattached Guy Wires or Stubs				
Guy Strain Insulators Pulled Apart or Broken				
Guy Guards Out of Position or Missing				
Guy Anchors Exposed				
Grading Changes or Washouts				
5) Pole Hardware & Attachments:				
Loose or Missing Hardware				
Insulators Unattached From Brackets				
Conductor Unattached From Insulators				
Riser Pole Hardware Damage				
Dip Pole Hardware Damage				
Insulators Flashed Over or Contaminated				
Tie Wires Unraveled				

Ground Wire Broken or Removed				
Ground Wire Guards Broken or Removed				
Missing Switch, Riser or Dip Pole ID Tag				

	Acceptable	Problem / Condition Description	Location / Work Order	Date Corrected
6) Other Equipment Installations:				
Telecommunications Attachments				
Cable TV Attachements				
Hydro One Attachements				
Accessibility Compromised				
7) Vegetation & Right-of-Way:				
Leaning or Broken "Danger" Trees				
Trees, Vines or Brush Growth Interference				
8) General				
Sufficient Space Observed				
Energized Conductors Adequately Barriered				
Grounding is Effective				

B. Underground System

1) Padmount Transformers & Enclosures:

Corrosion/Rust, Paint Condition				
Leaking Oil				
Lid or Cabinet Damage				
Missing Bolts				

Security Lock Damage				
Grade Changes				
Access Changes				

2) Switching & Protective Devices:

Structural Condition of Enclosure				
Security Condition of Enclosure				
Missing Switch ID Tag				

3) Conductors & Cables:

Exposed Cables				
Grade Changes Bringing Cable to Surface				

4) General

Sufficient Space Observed				
Energized Conductors Adequately Barriered				
Grounding is Effective				

NOTES:

Inspected by **Name:** _____

Position/Title: _____

Signature: _____

Appendix C:

Transformer Station Monthly Inspection For

Fort Frances Power Corporation - Substation Monthly Maintenance Inspections For The Month:

	Acceptable	Problem / Condition Description / Work Order	Date Corrected
1) Outside Yard:			
Condition of Driveway & Surrounding Yard			
Condition of Station Fence & Gates			
Condition of Signage			
Condition of Security Locks			
Grading Changes or Washouts Along Fence			
Operation of Yard Lights			
Condition of Yard Housekeeping			
Vegetation Growth Inside Fence Area			
2) Buildings - Exterior:			
Condition of Exterior Walls & Roofs			
Condition of Exterior Doors & Security Locks			
Operation of Exterior Lights			
3) Tower Structure:			
Leaning, Cracked or Bent Components			
Loose Bolts or Fasteners			
Exterior Corrosion/Rust			
Exterior Damage			

	Acceptable	Problem / Condition Description / Work Order	Date Corrected
4) T1 - Transformer:			
Leaking Oil			
Paint Condition			
Exterior Corrosion/Rust			
Exterior Damage			
5) T2 - Transformer:			
Leaking Oil			
Paint Condition			
Exterior Corrosion/Rust			
Exterior Damage			
6) T1 - Transformer DC Battery Bank:			
Leaking Fluid			
Condition of Jumpers & Plates			
Condition of Cabinet			
Test Individual Battery Cell Voltages			
7) T2 - Transformer DC Battery Bank:			
Leaking Fluid			
Condition of Jumpers & Plates			
Condition of Cabinet			
Test Individual Battery Cell Voltages			
8) Relays:			
Status of Reclosures & Flags			

	Acceptable	Problem / Condition Description / Work Order	Date Corrected
9) Buildings - Interior:			
Condition of Walls, Floors & Ceilings			
Operation of Lights			
Operation of DC Lights			
Operation of Heating & HVAC System			
Operation of Station Telephone			
Condition of Eyewash Station			
Condition of First Aid Kit			
Condition of Housekeeping			
10) General			
Sufficient Space Observed			
Energized Conductors Adequately Barriered			
Grounding is Effective			

NOTES:

Inspection Date:

Inspected by: **Name**

Position/Title

Signature

Appendix D:

Transformer Station Annual Inspection Form

Fort Frances Power Corporation - Substation Annual Maintenance Inspections
Year -

	Inspection Date	Acceptable	Problem / Condition Description / Work Order	Date Corrected
1) Tower Structure:				
Condition of Insulators				
Condition of Energizing Blades				
2) T1 - Transformer:				
Operation of Fans				
Condition of Bushings & Arrestors				
Condition of Tap Changer Cabinet				
Operation of Tap Changer				
Operation of Tap Changer Heater				
Oil Samples Taken & Sent for Analysis				
3) T2 - Transformer:				
Operation of Fans				
Condition of Bushings & Arrestors				
Condition of Tap Changer Cabinet				
Operation of Tap Changer				
Operation of Tap Changer Heater				
Oil Samples Taken & Sent for Analysis				
4) OCB's - Oil Circuit Breakers:				

Operation of Heaters				
Oil Samples Taken & Sent for Analysis				

5) Relays:

Operation of Relays (Breakers in Test Mode)				
Test & Re-Calibrate (3 years)				

	Inspection Date	**Acceptable**	**Problem / Condition Description / Work Order**	**Date Corrected**

6) T1 - Transformer DC Battery Bank:

Operation of Charger				
Calibrate Float				
Equalize Voltage				
Charge Batteries				
End-of-Life Battery Test (5years)				

7) T2 - Transformer DC Battery Bank:

Operation of Charger				
Calibrate Float				
Equalize Voltage				
Charge Batteries				
End-of-Life Battery Test (5years)				

8) Switch Gear:

Condition of Station Arrestors (Back Cabinet)				
Operation of Breakers (2 years)				
Cleaning of Breakers (2 years)				

Notes: _____

_____

_____

_____

_____

Inspected by **Name:** _____ **Position/Title:** _____.

Signature: _____

Appendix E:

Trouble Report / Field Interruption Form

Trouble Report

Date: Time Reported am/pm Regular Hours ☐ Call-Out Hours ☐

Time Dispatched _____am/pm Time Completed_____am/pm

Customer Name: _____.

Customer Address: _____.

Customer Phone No _____,

No Power ☐ Part Power ☐ Other ☐ Description :

.

Reported Details:

Feeder Reference #_____Switch Reference #_____.

Primary Fault ☐ Location of Fault:

Cause of Problem:

Description of Work Performed:

Vehicle Accident Information: ESA Reportable Yes ☐ No ☐

Police Incident No.: _____ Copy of Incident Report Attached Yes ☐ No ☐

Police Officer's Name: _____Badge # _____.

STATUS OF WORK: ☐ Work Completed ☐ Temporary Repairs Made

☐ Site Left In Safe Condition

_____ _____ _____

Name of Person Completing Report **Signature** **Date**

CERTIFICATE:
☐ No Undue Hazards Exist
☐ Approved Material Used
☐ Work in Accordance with Standard Designs
☐ Work Not in Accordance, Forward to General Superintendent
☐ **Is not in Accordance with Standard Designs**
☐ **Does not meet the safety standards**

_____ _____ _____

Name of Qualified Person **Signature** **Date**

Field Interruption Report

Date _____ Time Call Rec'd _____ ☐ Direct ☐ Answering Service

Name _____ Location _____

INTERRUPTION
Date: _____ Time: _____
# of Customers: _____ Duration (min): _____

RESTORATION
Date: _____ Time: _____
☐ Auto Reclosure Customer Min. _____

FAILURE DATA **Select One:** ☐ Overhead ☐ Underground
Feeder Affected By Outage: _____

Select one of the following Voltage Levels

☐ 120/240 V ☐ 120/208 V ☐ 347/600 V ☐ 600 V
☐ 4.16/2.4 kV ☐ 8.32/4.8 kV ☐ 13.8/8 kV ☐ 27.6/16 kV

Interrupting Device Designation: _____
☐ Breaker ☐ Fuse ☐ Recloser ☐ Switch
☐ Other: _____

Restored By
☐ Repair ☐ Replacement ☐ Load Transfer
☐ Sectionalizing ☐ Reclosing Device ☐ Other _____

Cause (Choose One)
☐ Human Element ☐ Lightning ☐ Loss Of Supply
☐ Scheduled Outage ☐ Tree Contact ☐ Unknown/Other ☐ Customer Request
☐ Adverse Environment ☐ Adverse Weather ☐ Defective Equipment ☐ Foreign Interference

(select one sub-category below) (select one sub-category below) (select one sub-category below) (select one sub-category below)

☐ Salt Spray	☐ Rain	☐ Arrester Failure	☐ Birds
☐ Industrial Contamination	☐ Freezing Rain	☐ Broken Insulator	☐ Animals
☐ Humidity	☐ Snow	☐ Cable Failure (insultn)	☐ Vehicles
☐ Corrosion	☐ High Winds	☐ Cable Fail. (mech. dam)	☐ Dig-Ins
☐ Vibration	☐ Extreme Temperatures	☐ Drop Leads	☐ Vandalism
☐ Fire	☐ Freezing Fog	☐ Elbow Failure	☐ Sabotage
☐ Flood	☐ Frost	☐ Loose Connection	☐ Other
☐ Other	☐ Other	☐ Termination Failure	
		☐ Splice Failure	
		☐ Switch Failure	
		☐ Transformer Failure	
		☐ Other/Unknown	

Comments _____

☐ Work Completed ☐ See Attached Sheet _____ prepared by

Appendix F:

Tier 2 Overhead Plant Detailed Asset Inspection Form (Sample)

FFPC Pole Number / Location	Pole Hammer Test	Pole Condition Assessment	Anchors & Guying	Pole-Top Assembly	Primary Conductor	Secondary Conductor	Transformer Setting	Vegetation	Third Party Attachments	Comments / Reason for Deficiency	Deficiency Criticality Rating
	S / U	S / U	S / U	S / U	S / U	S / U	S / U	S / U	S / U		
EXAMPLE	U	U	S	S	S	S	S	S	S	Extensive Damage - Woodpecker Holes	2
AP0001											
AP0002											
AP0003											
AP0004											
AP0005											
AP0006											
AP0007											
AP0008											
AP0009											
AP0010											
AP0011											
AP0012											
AP0013											
AP0016											

Appendix G:

Tier 2 Underground Plant Detailed Asset Inspection Form (Sample)

Tx Name	Lock Integrity	Enclosure/ Exterior Inspection	Internal Visual Inspection	General / Other Observations	Snow Pole Mounted / Removed	Explanation For U (Unsatisfactory) Rating	Deficiency Criticality Rating
	S / U	S / U	S / U	S / U	M / R		
Sample	U	S	S	S	X	Lock Failed	1
AT135	-	-	-	-	-	-	-
AT101	-	-	-	-	-	-	-
AT104	-	-	-	-	-	-	-
AT105	-	-	-	-	-	-	-
AT106	-	-	-	-	-	-	-
AT107	-	-	-	-	-	-	-
AT109	-	-	-	-	-	-	-
AT11	-	-	-	-	-	-	-
AT110	-	-	-	-	-	-	-
AT114	-	-	-	-	-	-	-
AT115	-	-	-	-	-	-	-
AT116	-	-	-	-	-	-	-
AT12	-	-	-	-	-	-	-
AT120	-	-	-	-	-	-	-
AT121	-	-	-	-	-	-	-
AT128	-	-	-	-	-	-	-

Appendix 5: FFPC June 24, 2013 Submission re Defining and Measuring Performance of Electricity Distributors (EB-2010-0379)

June 24, 2013

FFPC
FORT FRANCES POWER CORPORATION

Kristin Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 26th Floor
Toronto, Ontario M4P 1E4

Re. Consultation Report and Stakeholder Consultation Meetings in May Defining and Measuring Performance of Electricity Distributors (EB-2010-0379)

Please accept this correspondence as the formal comments of Fort Frances Power Corporation ("FFPC") on the issues addressed in the report prepared by Board Staff's expert consultant ("PEG") entitled, "Empirical Work in Support of Incentive Rate Setting in Ontario" (the "PEG Report").

Throughout the PEG Report, PEG underscores the importance of ensuring "apples to apples" benchmarking across distributors (see, for example, pages 37-38 of the PEG Report). For the purpose of benchmarking, PEG has grouped FFPC along with 17 other distributors which PEG has identified as having small output, small area, and below average customer growth (Peer Group E, Table 23 of the PEG Report).

FFPC is concerned that, given the unique circumstances of FFPC described in this letter, it might not be possible to make such an "apples to apples" comparison of FFPC to other distributors. FFPC has a unique feature which inflates its legal and administrative expenses relative to other distributors. In particular, FFPC is the custodian of a 1905 Agreement which greatly benefits residents of the Town of Fort Frances. To maintain that benefit, FFPC is required to incur significant legal and administrative expenses on an ongoing basis. FFPC is concerned that, by ignoring this unique circumstance applicable to FFPC, FFPC might appear to be less efficient than others in its peer group when the costs are entirely unrelated to efficiency, and are in fact prudently and effectively incurred to the benefit of customers.

As the Board is aware, the residents of the Town of Fort Frances are beneficiaries of a 1905 Agreement entered into between the Town and the local pulp and paper mill. The 1905 Agreement obligates the mill owner, or more precisely today, the owner of the generation assets on the Rainy River (today, H2O Power LP ("H2O")), to provide to the Town of Fort Frances, in perpetuity, 4,000 horsepower (2.984 Megawatts) at $14 per horsepower per annum (0.21416 cents per kilowatt hour) "for municipal purposes and for public utilities" [*Fort Frances v Boise Cascade Canada Ltd*., [1983] 1 SCR 171 at 184].

The 1905 Agreement is filed as a physical bilateral contract with the IESO and represents a financial obligation of H2O. Essentially, for 2.984 Megawatts, which represents approximately 25% of the power purchases of FFPC, H2O pays to the IESO the additional costs of power above 0.21416 cents per kilowatt hour, and the IESO credits FFPC for that amount. FFPC in turn credits its customers who, in effect, pay a blended commodity rate reflecting the benefit of the 1905 Agreement. The amount of the benefit currently exceeds $2.2 million annually.

Costs associated with maintaining the benefits of the 1905 Agreement are not insignificant. The accounting and billing for the benefits of the 1905 Agreement is labour-intensive. Further, given the value of the 1905 Agreement to the residents of the Town of Fort Frances, and the corresponding cost to the owner of the generation assets on the Rainy River, the 1905 Agreement is under constant attack from the

owner of the generation assets. Finally, the existence of the 1905 Agreement and the manner in which it reduces the price for power paid by the residents of the Town of Fort Frances relative to other ratepayers in the Province often requires that FFPC be given unique and specific treatment by government policy, regulation and legislation so as to preserve its benefits.

The specific cost elements associated with maintaining and enforcing the 1905 Agreement are best dealt with in FFPC's cost of service rebasing application. For present purposes, FFPC will explain the nature of the costs it incurs with respect to the following categories:

1. Ensuring regulatory and policy changes do not negate the benefit of the 1905 Agreement;

2. Enforcing the 1905 Agreement as against the various owners, from time to time, of the generation assets tied to the 1905 Agreement; and

3. Working with the IESO and the owner of the generation assets and internally to ensure that residents obtain a blended rate which reflects the financial benefit of the 1905 Agreement to which they are entitled.

Costs Related to Preserving the 1905 Agreement in the Face of Regulatory and Policy Changes

At pages 49-50 of the PEG Report, PEG makes an apt comment about costs related to regulatory changes and the difficulty of capturing company-specific cost pressures, as follows:

> A surprising finding of our cost model was the coefficient on the trend variable. This coefficient was estimated to be 0.014%. This implies that, even when input prices, outputs, and other business condition variables remain unchanged, costs for the Ontario electricity distribution industry still increased by an average of 1.4% per annum between 2002 and 2011. This is counter to the usual finding in cost research, where the coefficient on the trend variable is negative. One factor that could be contributing to these upward cost pressures is government policy implemented over the sample period. Another possibility is that there are cost pressures for a sizeable portion of the industry due to company-specific factors, rather than industry-wide policies, but it is difficult to capture these company-specific cost pressures in measurable business condition variables.

No doubt all distributors incur significant costs associated with regulation and changing government policy. However, in the experience of FFPC, it is forced to incur costs for proceedings and negotiations solely related to the 1905 Agreement, which other distributors do not. In the words of the PEG Report, FFPC appears to have a company-specific cost burden to maintain the 1905 Agreement.

In order to appreciate the time and expense that is required to support the 1905 Agreement, we can consider a few of the major regulatory changes that have required extensive work by FFPC:

- In 1999, Fort Frances Public Utilities Commission was required to apply for and obtain an Order of the Board exempting it and FFPC from Section 2.2.2 of the *Standard Supply Service Code*. If FFPC had not obtained this exemption, FFPC would have been required to meet all of its power needs through the IMO (as it then was) at market rates. By incurring the legal expenses to secure the exemption, FFPC retained the ability to obtain 25% of its power purchases at the low rate 0.21416 cents per kilowatt hour and pass on that benefit to its customers, allowing them to retain the lowest electricity rates in the Province.

- In 2002, Bill 210 required distributors to charge their standard supply customers at a fixed commodity rate of 4.3 cents per kilowatt hour. Regulation 339/02 filed under Bill 210 specifically exempted FFPC from this requirement so as to permit FFPC to continue to offer its customers the lower, blended rate consisting of power purchased from the IMO at 4.3 cents and power acquired from the owner of the generation assets on the Rainy River at 0.21416 cents. However, further regulations filed on Christmas Eve of that year, and in particular the revocation of Ontario Regulation 342/02, required all LDCs to pay the spot market price. As the Regulations stood at that time, FFPC was obliged to purchase power at spot prices and was not entitled to settlement payments under Ontario Regulation 435/02 (as were other LDCs) on an apparent theory that the 1905 Agreement would provide a blended commodity rate to the Town residents not to exceed 4.3 cents per kilowatt hour. This policy was objectionable to FFPC for two reasons. First, the residents of the Town had been paying *less* than 4.3 cents per kilowatt hour for power, and therefore a policy implemented to reduce the cost of power to Ontario consumers would increase the cost of power to Town residents. Second, the policy opened up the 1905 Agreement to the risk of challenge by the owner of the generating assets. In 1983 the Supreme Court of Canada [*Fort Frances v Boise Cascade Canada Ltd*., [1983] 1 SCR 171] had confirmed that the perpetual right to call for the delivery of power at the low rate of 0.21416 cents is "for municipal purposes and public utilities" and that the Town cannot call for power "for commercial purposes". Any diversion of the benefits of the 1905 Agreement from municipal purposes to the Province might have opened the Agreement to challenge, which no doubt the owner of the generation assets on the Rainy River would seize upon. Negotiations with the Province, including face-to-face meetings between FFPC counsel and then Minister of Energy John Baird and his staff were required to get the proper legislative exemptions in place to preserve the benefits of the 1905 Agreement.

- In 2004, Ontario Regulation 429/04 was enacted under section 25.33 of the *Electricity Act, 1998* (the "Global Adjustment Regulation"). FFPC worked with the Ministry to ensure that the Global Adjustments Regulation, and subsequent amendments to it, would be consistent with the 1905 Agreement and the Supreme Court of Canada decision. However, accounting for the Global Adjustment vis-à-vis customers eligible for the credit under the 1905 Agreement was complex, and true-ups with the IESO resulted in the inadvertent return of the benefit of the global adjustment cost savings on 2.984 Megawatts to the IESO. FFPC had to undertake extensive discussions with the IESO, OEB, OEFC and OPA regarding implementing accounting changes in order to reverse the error and once again ensure that the residents of the Town received all the benefit to which they are entitled under the 1905 Agreement.

Attacks on the 1905 Agreement by various owners of the generation assets on the Rainy River

It is not surprising that the owner of the generation assets, which now incurs a cost in the neighbourhood of $2.2 million annually under the 1905 Agreement, would attempt to attack it on every occasion. The most notorious attack was the legal attack by Boise Cascade which resulted in the Supreme Court of Canada decision confirming the perpetual right. There have been other attacks, while less public, which have required time and effort on behalf of FFPC management and the advice of counsel. Threats to negate the 1905 Agreement have taken various forms, including threats to shut down the generation assets on the Rainy River. FFPC management must be vigilant and incur prudent legal expenses in such battles.

Administration related to the 1905 Agreement

Administration of the 1905 Agreement is time-consuming. Approximately 30% of the work load of Lori Cain, Financial and Regulatory Officer at FFPC, is devoted to the day-to-day administration of the Agreement. This does *not* include extraordinary efforts on Lori's part which result from OEB and Ministry of Finance audits because of the Agreement. For example, the Ontario Energy Board requested audits of FFPC's Group 1 and Group 2 RSVA accounts, which alone consumed 9 months of Lori's time. Recently, the Ministry of Finance requested an HST audit. These audits were the result of FFPCs unique accounting requirements which make FFPC appear anomalous when compared to other LDCs. In

addition, approximately another 0.2 Full Time Equivalent is devoted by general administration towards the day-to-day administration of the Agreement. A conservative estimate is that 0.5 FTEs are required to manage the $2.2 million dollars annually across FFPC's customer base of approximately 3800 customers.

The day-to-day tasks involved with the administration of the Agreement include the following:

- **Agreement value determination**. Data must be extracted from the IESO's daily settlement statement to distinguish between Agreement and non-Agreement related charges. A monthly invoice must be prepared for H2O to receive recovery of Agreement-related charges from H2O. Further, all of the data must be compiled and incorporated into monthly and annual financial statements for FFPC's Board of Directors and auditors.

- **Review of regulations**. FFPC must constantly scan issues for applicability or conflict with the Agreement, including IESO charges, regulatory methodology and reporting, financial budgeting and reporting, customer billing, benefits, such as the Ontario Clean Energy Benefit, and taxation issues.

- **Adjustments to conform to regulatory reporting formats.** In order for FFPC to conform to regulatory reporting formats, FFPC must adjust all integrated regulatory and financial data by extraction of balances related to the Agreement.

- **Calculation and implementation of credits and rebates**. FFPC must calculate and provide the benefits of the Agreement to its customers in the form of monthly credits and annual rebates, including the issuance of rebate cheques which must be mailed to former FFPC customers.

- **Billing and customer communications**. FFPC must integrate the special accounting for the 1905 Agreement into its billing process and calculation algorithms. It must also process customer inquiries regarding the Agreement, as well as draft and publish periodic announcements related solely to the administration of the Agreement.

Conclusion

FFPC cannot speak to any company-specific cost pressures borne by other distributors. However, FFPC asks the Board to consider that, because of the unusual legal and administrative costs related to the 1905 Agreement, which to date have resulted in tremendous benefit to Fort Frances consumers, it might not be possible to compare "apples to apples" when considering the efficiency of FFPC.

Yours truly,

FORT FRANCES POWER CORPORATION

Per: *Original Signed By*

Joerg Ruppenstein, President and CEO

Davis: 14193141.1

FFPC
FORT FRANCES POWER CORPORATION

Filing Number: EB-2013-0130
Filed: December 20, 2013

EXHIBIT THREE

OPERATING REVENUE

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1			**Overview**
		1		Overview of Operating Revenue
	2			**Throughput Revenue**
		1		Weather Normalized Load and Customer/ Connection Forecast
			A	Monthly Data Used for Regression Analysis
	3			**Operating Revenue Variance Analysis**
		1		Variance Analysis on Throughput Revenue
		2		Variance Analysis on Other Operating Revenue

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of FFPC's operating revenue for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, the 2013 Bridge Year and the 2014 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

FFPC's 2014 forecasted revenues recovered through its currently approved distribution rates will be $1,427,725 (exclusive of all rate riders). This amount is determined by applying the currently approved distribution rates to the forecasted consumption and customer counts. FFPC's projected customer, volumes and revenues calculated at current rates are presented below.

Table 3.1.1: 2014 Projected Service Revenue Requirement at Existing Rates

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	37,751,518		39,480		475,734	332,213	807,947		807,947	56.59%
GS < 50 kW	13,617,679		4,860		141,086	89,877	230,962		230,962	16.18%
GS >50 to 4999 kW	26,376,324	67,294	564		136,522	241,875	378,397	9,335	369,062	25.85%
Street Lighting	366,947	1,055		12,072	14,124	3,219	17,343		17,343	1.21%
Unmetered and Scattered	48,552		72		2,090	320	2,411		2,411	0.17%
	78,161,020	**68,349**	**44,976**	**12,072**	**769,556**	**667,504**	**1,437,060**	**9,335**	**1,427,725**	**100%**

Under CGAAP FFPC is proposing a total Service Revenue Requirement of $1,965,387 for the 2014 Test Year. This amount includes a Base Revenue Requirement of $1,862,354 plus revenue offsets of $103,033 to be recovered through Other Distribution Revenue, as shown in Table 3.1.2 below.

(Note: Model produced Total Revenue of $1,842,415, difference of $61 due to rounding.)

Table 3.1.2: 2014 Proposed Service Revenue Requirement at Proposed Rates

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Proposed Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue
Residential	1,243,335	66.76%	18.54	$0.0135	$ 732,098	$ 511,237		1,243,335
GS < 50 kW	342,024	18.36%	42.99	$0.0098	$ 208,929	$ 133,095		342,024
GS >50 to 4999 kW	250,896	13.47%	164.56	$2.4879	$ 92,810	$ 158,086	$ 9,335	260,231
Street Lighting	23,017	1.24%	1.55	$4.0490	$ 18,745	$ 4,272		23,017
Unmetered and Scattered	3,143	0.17%	37.85	$0.0086	$ 2,726	$ 418		3,143
TOTAL	**1,862,415**	**100.00%**			**$ 1,055,308**	**$ 807,107**	**$ 9,335**	**$ 1,871,749**
					Total Revenue	**1,862,415**		

Throughput Revenue:

Information related to FFPC's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on this historical throughput revenue is also provided in this exhibit.

Overall load reductions from 2010 to the 2014 forecast amounts can be attributed to three major factors - seasonal weather conditions, economic downturn in the Town of Fort Frances and the success of conservation initiatives. As illustrated in Table 3.2.1 Summary of Forecast of this exhibit, average consumption per customer has declined in each rate class.

Information related to FFPC's throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year and CDM adjustments and known economic conditions.

A detailed variance analysis on the throughput revenue is set out in Exhibit 3, Tab 3 Schedule 1.

Other Revenue:

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues and Rental Revenues.

A detailed variance analysis on other revenue is set out in Exhibit 3, Tab 3, and Schedule 2.

1 Table 3.1.3- Other Operating Revenue

Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
						2013	2013	2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4235	Specific Service Charges	$ 29,751	$ 8,953	$ 9,003	$ 9,003	$ 9,000	$ 9,000	$ 9,849
4225	Late Payment Charges	$ 24,747	$ 23,669	$ 27,178	$ 27,178	$ 24,000	$ 24,000	$ 25,000
4082	Retail Services Revenues	$ 1,553	$ 540	$ 3	$ 3			
4084	Service Transactions Req	$ 1,475	$ 1,130	$ 583	$ 583			
4086	SSS Admin Revenue			$ 10,906	$ 10,906	$ 11,332	$ 11,332	$ 11,184
4210	Electric Property-Rent	$ 47,328	$ 46,784	$ 47,162	$ 47,162	$ 48,000	$ 48,000	$ 48,000
4230	Sales of Water & Power			$ 12,419	$ 12,419	$ 5,000	$ 5,000	
4245	Govern Assist Direct Income		$ 1,120	$ 1,120	$ 1,120			
4324	Special Purpose Recovery	$ 18,810	-$ 1,068					
4325	Rev from Merchandise	$ 73,454	$ 54,814	$ 37,235	$ 37,235	$ 45,000	$ 45,000	$ 25,000
4330	Exp from Merchandise	-$ 45,116	-$ 51,346	-$ 33,835	-$ 33,835	-$ 41,500	-$ 41,500	-$ 21,000
4355	Gain on Disposition		$ 5,127			$ 15,000	$ 13,500	
4360	Loss on Disposition	-$ 1,220						
4375	Rev from Non-Utility	$ 134,362	$ 38,484	$ 36,971	$ 36,971	$ 65,000	$ 65,000	$ 65,000
4380	Exp from Non-Utility	-$ 116,887	-$ 36,059	-$ 36,522	-$ 36,522	-$ 60,000	-$ 60,000	-$ 60,000
4385	Non-Utility Rental	$ 27,328	$ 22,949	$ 1,673	$ 1,673			
4390	Misc Non Operating Income		$ 28,397					
Specific Service Charges		$ 29,751	$ 8,953	$ 9,003	$ 9,003	$ 9,000	$ 9,000	$ 9,849
Late Payment Charges		$ 24,747	$ 23,669	$ 27,178	$ 27,178	$ 24,000	$ 24,000	$ 25,000
Other Operating Revenues		$ 50,355	$ 49,574	$ 72,192	$ 72,192	$ 64,332	$ 64,332	$ 59,184
Other Income or Deductions		$ 90,731	$ 61,297	$ 5,523	$ 5,523	$ 23,500	$ 22,000	$ 9,000
Total		$ 195,584	$ 143,494	$ 113,896	$ 113,896	$ 120,832	$ 119,332	$ 103,033

2

THROUGHPUT REVENUE

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by FFPC to prepare the weather normalized load and customer/connection forecast used to design the proposed 2014 electricity distribution rates.

In summary, FFPC has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, FFPC submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. FFPC has the data for the amount of electricity (in kWh) purchased from the IESO for use by FFPC's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to bill kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During the review process of previous cost of service applications, Intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly kWh by rate class. FFPC reviewed the data required to conduct the regression analysis on an individual rate class basis and does not have a method to properly determine monthly consumed values by rate class.

In addition, Board staff and Intervenors expressed concern that the regression analysis assigned coefficients to some variables that were counter intuitive. For example, the customer variable

would have a negative coefficient assigned to it which meant as the number of customers increased as the energy forecast decreased. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. FFPC has attempted to address these concerns in the load forecast used in this Application. As a result, variables such as Unemployment and Employment data in the Northwestern Region, FFPC CDM Activity and Number of Peak Hours were tested but not used since they had counter intuitive coefficients and/or they were not statistically significant.

Based on the OEB's approval of this methodology in a number of previous cost of service applications and based on the discussion that follows, FFPC submits that its load forecasting methodology is reasonable for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by FFPC in this Application.

The information in the table below provides weather actual data from 2003 to 2012, while 2013 and 2014 are weather normalized. FFPC does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and streetlight and unmetered loads are measured as connections.

Table 3.2.1 – Fort Frances Weather Normal Load Forecast

Fort Frances Weather Normal Load Forecast for 2014 Rate Application												
	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	2014 Weather Normal
By Class												
Residential												
Customers	3,390	3,385	3,412	3,380	3,332	3,305	3,309	3,307	3,308	3,308	**3,299**	**3,290**
kWh	38,329,311	38,423,702	39,001,595	38,674,263	40,986,845	40,872,765	40,921,847	38,642,702	38,681,251	37,169,840	**37,551,665**	**37,751,518**
General Service≤ 50 kW												
Customers	474	485	445	437	438	426	418	419	421	417	**411**	**405**
kWh	23,250,299	21,496,720	16,510,730	15,350,875	15,178,972	15,341,926	15,681,898	15,009,183	15,033,140	14,736,725	**14,200,992**	**13,617,679**
General Service≥ 50 kW												
Customers	40	43	47	47	47	49	47	51	46	46	**47**	**47**
kWh	16,680,161	20,470,323	26,878,664	27,269,745	26,441,963	25,476,812	24,920,577	25,386,687	24,978,251	23,898,102	**25,160,587**	**26,376,324**
kW	54,293	59,088	63,396	58,180	63,900	61,980	61,771	65,577	63,157	58,302	**64,192**	**67,294**
Streetlights												
Connections	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	**1,006**	**1,006**
kWh	1,092,500	1,329,072	1,211,465	1,061,383	1,270,115	1,179,263	1,014,240	1,158,527	1,162,298	1,108,600	**765,211**	**366,947**
kW	3,310	3,310	3,310	3,310	3,310	3,310	3,310	3,310	3,310	3,310	**2,199**	**1,055**
Unmetered Loads												
Connections	8	8	8	8	7	6	6	6	6	6	**6**	**6**
kWh	192,228	192,228	192,228	192,228	175,428	75,264	70,728	64,814	62,628	62,628	**55,151**	**48,552**
Total of Above												
Customer/Connections	**4,918**	**4,927**	**4,918**	**4,878**	**4,830**	**4,792**	**4,786**	**4,789**	**4,787**	**4,783**	**4,769**	**4,754**
kWh	**79,544,499**	**81,912,045**	**83,794,682**	**82,548,494**	**84,053,323**	**82,946,030**	**82,609,290**	**80,261,913**	**79,917,568**	**76,975,895**	**77,733,606**	**78,161,019**
kW applicable classes	**57,603**	**62,398**	**66,706**	**61,490**	**67,210**	**65,290**	**65,081**	**68,887**	**66,467**	**61,612**	**66,391**	**68,348**
Total from Model												
Customer/Connections	**4,918**	**4,927**	**4,918**	**4,878**	**4,830**	**4,792**	**4,786**	**4,789**	**4,787**	**4,783**	**4,769**	**4,754**
kWh	**79,544,499**	**81,912,045**	**83,794,682**	**82,548,494**	**84,053,323**	**82,946,030**	**82,609,290**	**80,261,913**	**79,917,568**	**76,975,895**	**77,733,606**	**78,161,019**
kW from applicable classes	**57,603**	**62,398**	**66,706**	**61,490**	**67,210**	**65,290**	**65,081**	**68,887**	**66,467**	**61,612**	**66,391**	**68,348**

FFPC's Annual Energy Usage per Customer/Connection for 2003-2012 and the forecasted 2013 bridge and 2014 Test year are shown above in Table 3.2.2, on a rate class basis.

Table 3.2.2 FFPC Annual Energy Usage per Customer/Connection (kWh per Customer/Connection)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 Weather Normal	2014 Weather Normal
Residential												
Customers	3,390	3,385	3,412	3,380	3,332	3,305	3,309	3,307	3,308	3,308	**3,299**	**3,290**
kWh/Customer	**11,307**	**11,351**	**11,431**	**11,442**	**12,301**	**12,367**	**12,367**	**11,685**	**11,693**	**11,236**	**11,383**	**11,474**
General Service< 50 kW												
Customers	474	485	445	437	438	426	418	419	421	417	**411**	**405**
kWh/Customer	**49,051**	**44,323**	**37,103**	**35,128**	**34,655**	**36,014**	**37,517**	**35,821**	**35,708**	**35,340**	**34,543**	**33,599**
General Service> 50 kW												
Customers	40	43	47	47	47	49	47	51	46	46	**47**	**47**
kWh/Customer	**417,004**	**476,054**	**571,886**	**580,207**	**562,595**	**519,935**	**530,225**	**497,778**	**543,005**	**519,524**	**538,541**	**555,863**
Streetlights												
Connections	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	**1,006**	**1,006**
kWh/Connection	**1,086**	**1,321**	**1,204**	**1,055**	**1,263**	**1,172**	**1,008**	**1,152**	**1,155**	**1,102**	**761**	**365**
Unmetered Loads												
Connections	8	8	8	8	7	6	6	6	6	6	**6**	**6**
kWh/Connection	**24,029**	**24,029**	**24,029**	**24,029**	**25,061**	**12,544**	**11,788**	**10,802**	**10,438**	**10,438**	**9,490**	**8,626**

FFPC's distribution area is held within the municipal boundaries of the Town of Fort Frances. The town's main employer, Resolute Forest Products, has reduced its operations, which may reduce further or cease operations in the future.

FFPC's customer count and consumption and demand predictions represent the economic regression of our rate base.

LOAD FORECAST AND METHODOLOGY

FFPC's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates independent variables that impact the monthly historical load pattern for FFPC. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased Kilowatt Hour Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); number of days in month, spring fall flag, number of customers, Ontario real GDP and a 2012 flag. The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2012 to determine a prediction formula with coefficients for each independent variable. This provides 120 monthly data points which represent a reasonable data set for use in a regression analysis. Consistent with the approach used by many other distributors in their cost of service applications, FFPC submits that it is appropriate to review the impact of weather over the period January 2003 to December 2012 and then determine the average weather conditions over this period which would be applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, FFPC has also provided a sensitivity analysis showing the impact on the 2014

forecast of purchases assuming weather normal conditions are based on a 20-year trend of weather data.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by FFPC to predict weather normal purchases for 2013 and 2014:

FFPC's Monthly Predicted kWh Purchases

+ Heating Degree Days * 4,223
+ Cooling Degree Days * 15,610
+ Number of Days in the Month * 217,336
+ Spring Fall Flag * (418,031)
+ Number of Customers * 3571
+ Ontario Real GCP Monthly % * 50,374
+ 2012 Flag * (517,554)
+ Intercept of (211,811,635)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from the Fort Frances Weather Station 'A' up to 2007 and the Fort Frances Weather Station RCS from 2008 onward.

b) The calendar provided information related to number of days in the month and the spring fall flag.

c) The billing system provided historical monthly number of customers and the forecasted number of customer was based on the customer forecast discussed below.

d) For 2003 to 2006 the source of data for the Ontario Real GDP information was the 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance. For 2007 and 2008, the source was the 2010 Ontario Economic Outlook and Fiscal Review – 2010 Fall Update. For 2009, the 2012 Ontario Economic Outlook and Fiscal Review - 2012 Fall Update provided the Ontario Real GDP. For 2010 to 2014, the Ontario Real GDP was sourced from the 2013 Ontario Budget.

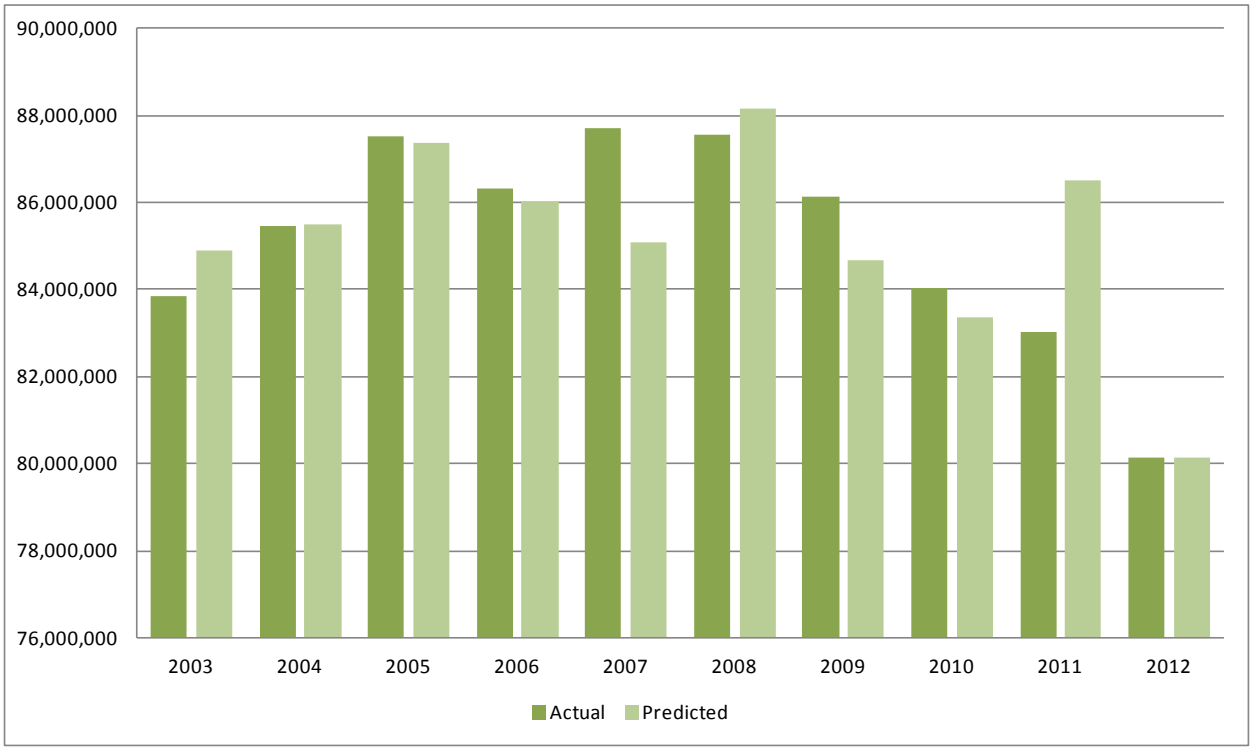
e) The 2012 flag was set to one for all months in 2012 and has assumed to continue into the forecast years of 2013 and 2014. FFPC attempted to address the economic downturn that occurred in 2012 resulting mainly from the reduction in operations of Resolute Forest Products by testing an unemployment variable but the variable was not supportable as being statistically sound. The 2012 flag variable was tested and proved to be statistically significant with an intuitive coefficient. In FFPC view, this variable addresses the economic downturn that occurred in 2012. Since the economic conditions of 2012 are expected to continue in 2013 and 2014, and most likely worsen, FFPC has assumed the 2012 flag is set to one for all months in 2013 and 2014.

The prediction formula has the following statistical results:

Table 3.2.3 : Statistical Results	
Statistic	Value
R Square	97%
Adjusted R Square	97%
F Test	479.61
T-stats by Variable	
Intercept	4.85
Heating Degree Days	44.63
Cooling Degree Days	9.66
Number of Days in a Month	7.26
Spring Fall Flag	(7.22)
Number of Customers	4.33
Ontario Real GDP Monthly %	4.88
2012 Flag	(5.89)
Mean Average % Error	2.70%

The annual results of the above prediction formula compared to the actual annual purchases from 2003 to 2012 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.

Chart 3.2.4: Actual vs. Predicted (kWh)



The following table outlines the data that supports the above chart. In addition, the predicted total system purchases for FFPC are provided for 2013 and 2014. For 2013 and 2014 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2014 are provided with a 20 year trend assumption for weather normalization.

Table 3.2.5 Total System Purchases

Year	Actual	Predicted	% Difference
Purchased Energy (kWh)			
2003	83,865,020	84,886,866	1.2%
2004	85,465,666	85,501,944	0.0%
2005	87,506,711	87,374,194	-0.2%
2006	86,305,341	86,028,269	-0.3%
2007	87,693,969	85,086,375	-3.0%
2008	87,543,088	88,159,245	0.7%
2009	86,145,680	84,678,078	-1.7%
2010	84,047,771	83,357,807	-0.8%
2011	83,026,301	86,526,770	4.2%
2012	80,138,104	80,138,104	0.0%
2013 Weather Normal		81,839,918	
2014 Weather Normal		82,927,700	
2014 Weather Normal - 20 Year Trend		82,401,534	

The weather normalized amount for 2014 is determined by using 2014 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2003 to December 2012 (i.e. ten years). The 2014 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1993 to December 2012

The weather normal ten year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The ten year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by FFPC using the average loss factor from 2003 to 2012 of 1.0456. With this average loss factor the total weather normalized billed energy will be 78,269,258 kWh for 2013 (i.e. 81,839,918/1.0456) and 79,309,581 kWh for 2014 (i.e. 82,927,700/1.0456) before adjustments for 2013 and 2014 CDM programs.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 3.2.6 Historical Customer/Connection Data

	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads	Total
2003	3,390	474	40	1,006	8	4,918
2004	3,385	485	43	1,006	8	4,927
2005	3,412	445	47	1,006	8	4,918
2006	3,380	437	47	1,006	8	4,878
2007	3,332	438	47	1,006	7	4,830
2008	3,305	426	49	1,006	6	4,792
2009	3,309	418	47	1,006	6	4,786
2010	3,307	419	51	1,006	6	4,789
2011	3,308	421	46	1,006	6	4,787
2012	3,308	417	46	1,006	6	4,783

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding reduction rate from 2003 to 2012.

Table 3.2.7 Historical Customer/Connection Data	Residential	General Service	General Service	Street Lighting	Unmetered
2003					
2004	99.9%	102.3%	107.5%	100.0%	100.0%
2005	100.8%	91.8%	109.3%	100.0%	100.0%
2006	99.1%	98.2%	100.0%	100.0%	100.0%
2007	98.6%	100.2%	100.0%	100.0%	87.5%
2008	99.2%	97.3%	104.3%	100.0%	85.7%
2009	100.1%	98.1%	95.9%	100.0%	100.0%
2010	99.9%	100.2%	108.5%	100.0%	100.0%
2011	100.0%	100.5%	90.2%	100.0%	100.0%
2012	100.0%	99.0%	100.0%	100.0%	100.0%
Geometric Mean	**99.7%**	**98.6%**	**101.6%**	**100.0%**	**96.9%**
Growth Rate	**-0.3%**	**-1.4%**	**1.6%**	**0.0%**	**-3.1%**

The resulting geometric mean was first applied to the 2012 customer/connection numbers to determine the forecast of customer/connections in 2013. Then, the geometric mean was applied again to the 2013 value to determine the 2014 customer/connection forecast. The following table outlines the forecast of customers and connections by rate class.

Table 3.2.8 Customer/Connection Forecast Year	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads	Total
Forecast Number of Customers/Connections						
2013	3,299	411	47	1,006	6	4,769
2014	3,290	405	47	1,006	6	4,754

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2003 to 2012.

Table 3.2.9 Historical Annual kWh Usage per Customer/Connection Data

	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads
2003	11,307	49,051	417,004	1,086	24,029
2004	11,351	44,323	476,054	1,321	24,029
2005	11,431	37,103	571,886	1,204	24,029
2006	11,442	35,128	580,207	1,055	24,029
2007	12,301	34,655	562,595	1,263	25,061
2008	12,367	36,014	519,935	1,172	12,544
2009	12,367	37,517	530,225	1,008	11,788
2010	11,685	35,821	497,778	1,152	10,802
2011	11,693	35,708	543,005	1,155	10,438
2012	11,236	35,340	519,524	1,102	10,438

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table 3.2.10 Growth Rate in kWh Usage per Customer/Connection					
	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads
2003					
2004	0.39%	-9.64%	14.16%	21.65%	0.00%
2005	0.70%	-16.29%	20.13%	-8.85%	0.00%
2006	0.10%	-5.32%	1.45%	-12.39%	0.00%
2007	7.51%	-1.35%	-3.04%	19.67%	4.30%
2008	0.54%	3.92%	-7.58%	-7.15%	-49.95%
2009	0.00%	4.17%	1.98%	-13.99%	-6.03%
2010	-5.51%	-4.52%	-6.12%	14.23%	-8.36%
2011	0.07%	-0.32%	9.09%	0.33%	-3.37%
2012	-3.91%	-1.03%	-4.32%	-4.62%	0.00%
Growth Rate	-0.27%	-1.41%	1.57%	0.00%	-3.15%

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2012 value to determine the 2013 forecast. The geometric mean is applied again to the 2013 value to determine the 2014 forecast and the resulting usage forecast is as follows:

Table 3.2.11 Forecast Annual kWh Usage per Customer/Connection					
Year	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads
Forecast Annual kWh Usager per Customers/Connections					
2013	11,229	34,076	532,369	1,102	9,514
2014	11,221	32,857	545,532	1,102	8,673

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3.2.8 by the forecast of annual

usage per customer/connection from Table 3.2.11. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 3.2.12: Non-Normalized Weather Billed Energy Forecast

Year	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads	Total
Non-normalized Weather Billed Energy Forecast (kWh)						
2013	37,551,665	14,200,992	25,160,587	765,211	55,151	77,733,606
2014	37,751,518	13,617,679	26,376,324	366,947	48,552	78,161,019

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 78,269,258 kWh for 2013 and 79,309,581 kWh for 2014 before adjustments for 2013 and 2014 CDM programs.

The difference between the non-normalized and normalized forecast adjustments is 536 MWh in 2013 (i.e. 78,269 – 77,733) and 1,148 MWh in 2014 (i.e. 79,309 – 78,161). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for FFPC for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3.2.13 Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads
Weather Sensitivity				
88.40%	88.40%	76.80%	0%	0%

For the GS > 50 kW class the weather sensitivity amount of 76.8% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. FFPC agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, FFPC has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 76%, or 88%.

The difference between the non-normalized and normalized forecast of 536 MWh in 2013 and 1,148 MWh in 2014 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

CDM ADJUSTMENT

In addition a manual adjustment has been made to reflect the impact of 2013 and 2014 CDM programs on the load forecast. FFPC has made this adjustment to reflect the "net" impact of 2013 and 2014 CDM programs on the load forecast.

The 2011 and 2012 savings from 2011 and 2012 CDM programs are known. The results of the 2011 and 2012 programs determines the savings that will be needed from 2013 to 2014 programs in order to achieve the licensed 4 year CDM target. Based on the following table, the 2011 programs will contribute 11.7% to the four year target and the 2012 programs will contribute 37.9% to the four year target. The following table indicates that assuming persistence, 2013 to 2014 programs will need to achieve 16.8% of the four year target each year in order to achieve the four year target.

Table 3.2.14: 4 Year (2011-2014) kWh Target:					
3,640,000					
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	2.94%	2.94%	2.94%	2.92%	11.75%
2012 CDM Programs		12.57%	12.57%	12.53%	37.67%
2013 CDM Programs			16.86%	16.86%	33.72%
2014 CDM Programs				16.86%	16.86%
Total in Year	**2.9%**	**15.5%**	**32.4%**	**49.2%**	**100.0%**
kWh					
2011 CDM Programs	107,133	107,133	107,133	106,295	427,694
2012 CDM Programs		457,592	457,592	455,986	1,371,170
2013 CDM Programs			613,712	613,712	1,227,424
2014 CDM Programs				613,712	613,712
Total in Year	**107,133**	**564,725**	**1,178,437**	**1,789,705**	**3,640,000**

Based on the approved method used in the 2013 cost of service applications, the above table suggests that in 2013, the savings will be one half of 2012 programs plus one half of 2013 programs for a total of 535,652 kWh on a net basis. In FFPC's view, the 2013 load forecast should be adjusted by 535,652 kWh to reflect CDM savings.

Also based on the approved method used in the 2013 cost of service applications, the above table also suggests that in 2014, the savings will be one half of 2012 programs plus a full year of 2013 programs plus one half of 2014 programs for a total of 1,148,561 kWh on a net basis. In FFPC's view, the 2014 load forecast should be adjusted by 1,149,561 kWh to reflect CDM savings.

However, in 2013 of the 535,653 kWh in net savings 343,389 kWh will be assigned to the Street Light class and in 2014, 741,653 kWh of the total 1,146,283 kWh CDM savings will be assigned to the Street Light class. This reflects the impact of savings in street light load of 67% to account for a LED conversion program as part of the Town of Fort Frances's Sustainability Initiatives. By the end of 2013, this conversion will replace all existing fixtures with new energy efficient LED fixtures that are expected to

use only 33% of the original wattage. FFPC, in a proactive measure, has installed a smart meter on an isolated street light circuit to record, for comparison purposes, the consumed wattage and dusk to dawn lighting hours with the new fixtures. This usage data will also be used to bill the Town of Fort Frances in more accurate manner.

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management [EB-2012-0003], issued April 26, 2012, it is FFPC's understanding that as part of this application expected CDM savings in 2014 from 2011, 2012, 2013 and 2014 programs will need to be established for LRAM variance accounts purposes. It is FFPC's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is FFPC's view the units used for the 2014 LRAM variance account should also be on a net basis. Based on the net information in Table 3.2.15, FFPC expects to achieve 1,227,424 net kWh savings in 2014 from 2011 to 2014 CDM programs. For LRAM variance account purposes, the following table outlines how this expected savings has been allocated to rate class using the 2014 information from Table 3.2.14. The expected kW saving has also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from Table 3.2.21.

Table 3.2.15: Expected Saving for LRAM Variance Account

	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads	Total
kWh	507,965	183,232	356,183	741,653	672	1,789,706
kW where applicable			909	2,131		3,040

**Streetlight reduction due to LED Retrofit and GS>50kW calculated on prorata reduction.*

The following table outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3.2.16: Alignment of Non-Normal to Weather Normal Forecast

Year	Residential	General Service < 50 kW	General Service > 50 kW	Street Lighting	Unmetered Loads	Total
Non-Normalized Weather Billed Energy Forecast (kWh)						
2013 Non-Normalized Bridge	37,043,195	14,008,703	24,872,239	1,108,600	55,291	77,088,027
2014 Non-Normalized Test	36,916,981	13,316,646	25,886,083	1,108,600	48,813	77,277,123
Weather Adjustment (kWh)						
2013	602,207	227,738	351,287	0	0	1,181,232
2014	1,031,755	372,173	628,530	0	0	2,032,458
CDM Adjustment (kWh)						
2013	-93,737	-35,449	-62,938	-343,389	-140	-535,652
2014	-197,218	-71,140	-138,289	-741,653	-261	-1,148,562
Weather Corrected Forecast (kWh)						
2013	**37,551,665**	**14,200,992**	**25,160,587**	**765,211**	**55,151**	**77,733,606**
2014	**37,751,518**	**13,617,679**	**26,376,324**	**366,947**	**48,552**	**78,161,019**

Billed KW Load Forecast

There are two rate classes that charge volumetric distribution on per kW basis. These include GS > 50 kW and Street Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 3.2.17 Historical Annual kW per Applicable Rate Class			
Year	GS>50 kW	Street Lighting	Total
Billed Annual kW			
2003	54,293	3,310	57,603
2004	59,088	3,310	62,398
2005	63,396	3,310	66,706
2006	58,180	3,310	61,490
2007	63,900	3,310	67,210
2008	61,980	3,310	65,290
2009	61,771	3,310	65,081
2010	65,577	3,310	68,887
2011	63,157	3,310	66,467
2012	58,302	3,310	61,612
Bridge 2013	64,192	2,199	66,391
Test 2014	67,294	1,055	68,348

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2003 to 2012.

Table 3.2.18 Historical kW/kWh Ratio per Applicable Rate Class		
Year	GS>50 kW	Street Lighting
Ratio of kW to kWh		
2003	0.3255%	0.3030%
2004	0.2887%	0.2490%
2005	0.2359%	0.2732%
2006	0.2133%	0.3119%
2007	0.2417%	0.2606%
2008	0.2433%	0.2807%
2009	0.2479%	0.3264%
2010	0.2583%	0.2857%
2011	0.2528%	0.2848%
2012	0.2440%	0.2986%
Average 2003-2012	**0.2551%**	**0.2874%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3.2.16 to provide the forecast of kW by rate class as shown in Table 3.2.17.

Table 3.2.2, shown at the beginning of this schedule provides a summary of the billing determinants by rate class that will be used to develop the proposed rates.

Appendix A

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	Number of Customers	Ontario Real GDP Monthly %	2012 Flag	Predicted Purchases
Jan-03	9,456,060	1041	0	31	0	3,901	125.66	0	9,584,470
Feb-03	8,440,797	953	0	28	0	3,902	125.81	0	8,570,026
Mar-03	7,925,709	759	0	31	1	3,902	125.95	0	7,994,971
Apr-03	6,163,100	418	0	30	1	3,903	126.10	0	6,344,591
May-03	5,395,677	193	0	31	1	3,904	126.24	0	5,625,559
Jun-03	5,521,290	71	27	30	0	3,904	126.39	0	5,744,944
Jul-03	6,158,388	22	45	31	0	3,905	126.54	0	6,033,625
Aug-03	6,433,503	19	90	31	0	3,906	126.68	0	6,732,030
Sep-03	5,709,375	171	17	30	1	3,906	126.83	0	5,610,868
Oct-03	6,330,051	364	3	31	1	3,907	126.98	0	6,438,701
Nov-03	7,651,101	680	0	30	1	3,908	127.12	0	7,523,603
Dec-03	8,679,969	802	0	31	0	3,909	127.27	0	8,683,479
Jan-04	10,134,225	1165	0	31	0	3,909	127.53	0	10,230,336
Feb-04	8,199,042	799	0	29	0	3,910	127.80	0	8,267,511
Mar-04	7,729,098	665	0	31	1	3,911	128.06	0	7,732,469
Apr-04	6,406,005	425	0	30	1	3,912	128.32	0	6,517,913
May-04	6,009,855	299	0	31	1	3,912	128.59	0	6,221,631
Jun-04	5,540,424	113	6	30	0	3,913	128.85	0	5,739,370
Jul-04	6,251,832	44	44	31	0	3,912	129.12	0	6,264,639
Aug-04	5,832,882	118	5	31	0	3,912	129.38	0	5,987,040
Sep-04	5,909,820	95	24	30	1	3,911	129.65	0	5,571,362
Oct-04	6,554,565	341	0	31	1	3,910	129.92	0	6,455,431
Nov-04	7,264,359	539	0	30	1	3,909	130.19	0	7,084,703
Dec-04	9,633,559	941	0	31	0	3,909	130.45	0	9,429,539
Jan-05	10,197,009	1086	0	31	0	3,908	130.74	0	10,054,278
Feb-05	7,931,365	779	0	28	0	3,907	131.03	0	8,115,966
Mar-05	8,064,613	759	0	31	1	3,906	131.33	0	8,278,312
Apr-05	6,304,988	330	1	30	1	3,906	131.62	0	6,271,091
May-05	6,189,587	234	0	31	1	3,905	131.91	0	6,083,857
Jun-05	6,219,927	41	41	30	0	3,904	132.20	0	6,120,100
Jul-05	6,876,788	26	90	31	0	3,901	132.50	0	7,036,334
Aug-05	6,418,010	61	39	31	0	3,897	132.79	0	6,396,089
Sep-05	5,916,795	135	20	30	1	3,894	133.09	0	5,782,035
Oct-05	6,571,998	354	2	31	1	3,891	133.38	0	6,648,293
Nov-05	7,667,940	604	0	30	1	3,887	133.68	0	7,459,032
Dec-05	9,147,691	848	0	31	0	3,884	133.98	0	9,128,808
Jan-06	8,645,184	774	0	31	0	3,881	134.25	0	8,816,587
Feb-06	8,433,483	928	0	28	0	3,877	134.53	0	8,816,160
Mar-06	7,908,257	648	0	31	1	3,874	134.81	0	7,871,758
Apr-06	6,151,308	293	0	30	1	3,871	135.08	0	6,154,252
May-06	6,218,083	179	21	31	1	3,867	135.36	0	6,225,697
Jun-06	6,146,444	55	19	30	0	3,864	135.64	0	5,862,266
Jul-06	7,123,470	7	88	31	0	3,860	135.92	0	6,952,773
Aug-06	6,443,073	32	23	31	0	3,856	136.20	0	6,053,920
Sep-06	5,861,771	180	9	30	1	3,852	136.48	0	5,827,920
Oct-06	6,849,480	458	0	31	1	3,848	136.76	0	7,075,751
Nov-06	7,647,750	600	0	30	1	3,844	137.04	0	7,457,915
Dec-06	8,877,038	794	0	31	0	3,841	137.33	0	8,913,270
Jan-07	9,432,908	905	0	31	0	3,837	137.55	0	9,380,346
Feb-07	9,228,910	814	0	28	0	3,833	137.78	0	8,338,089
Mar-07	8,025,208	515	0	31	1	3,829	138.01	0	7,307,175
Apr-07	6,654,507	359	0	30	1	3,825	138.23	0	6,430,599
May-07	5,912,182	158	9	31	1	3,821	138.46	0	5,936,487
Jun-07	6,071,468	43	50	30	0	3,817	138.69	0	6,289,743
Jul-07	6,811,577	29	69	31	0	3,814	138.92	0	6,735,405
Aug-07	6,209,810	47	26	31	0	3,811	139.15	0	6,141,468
Sep-07	5,771,471	163	14	30	1	3,808	139.38	0	5,815,210
Oct-07	6,424,810	320	0	31	1	3,805	139.61	0	6,480,913
Nov-07	7,619,728	569	0	30	1	3,802	139.84	0	7,314,955
Dec-07	9,531,390	798	0	31	0	3,799	140.07	0	8,915,985

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	Number of Customers	Ontario Real GDP Monthly %	2012 Flag	Predicted Purchases
Jan-08	9,728,566	1025	0	31	0	3,795	139.97	0	9,860,477
Feb-08	9,025,530	982	0	29	0	3,792	139.86	0	9,225,767
Mar-08	8,220,022	759	0	31	1	3,789	139.76	0	8,287,234
Apr-08	6,595,251	473	0	30	1	3,786	139.65	0	6,845,279
May-08	5,974,447	322	0	31	1	3,783	139.55	0	6,405,619
Jun-08	5,625,602	103	8	30	0	3,780	139.44	0	5,793,935
Jul-08	6,179,271	43	19	31	0	3,780	139.34	0	5,921,784
Aug-08	6,267,360	50	26	31	0	3,779	139.23	0	6,057,805
Sep-08	5,631,253	178	8	30	1	3,779	139.13	0	5,665,915
Oct-08	6,344,212	369	0	31	1	3,778	139.02	0	6,560,378
Nov-08	7,643,732	613	0	30	1	3,778	138.92	0	7,367,753
Dec-08	10,307,842	1127	0	31	0	3,777	138.81	0	10,167,299
Jan-09	10,493,890	1164	0	31	0	3,777	138.44	0	10,300,741
Feb-09	8,314,570	882	0	28	0	3,776	138.06	0	8,438,772
Mar-09	8,181,014	745	0	31	1	3,776	137.69	0	8,071,848
Apr-09	6,496,237	437	0	30	1	3,775	137.31	0	6,533,155
May-09	5,925,166	287	0	31	1	3,775	136.94	0	6,098,590
Jun-09	5,762,012	119	20	30	0	3,774	136.57	0	5,877,402
Jul-09	5,684,267	81	1	31	0	3,774	136.20	0	5,619,643
Aug-09	5,876,387	81	25	31	0	3,775	135.83	0	5,971,495
Sep-09	6,025,850	76	14	30	1	3,775	135.47	0	5,125,677
Oct-09	6,652,375	448	0	31	1	3,775	135.10	0	6,686,643
Nov-09	7,017,451	495	0	30	1	3,775	134.73	0	6,651,124
Dec-09	9,716,461	977	0	31	0	3,776	134.37	0	9,302,989
Jan-10	9,777,652	1001	0	31	0	3,776	134.72	0	9,425,145
Feb-10	8,208,207	868	0	28	0	3,776	135.08	0	8,228,470
Mar-10	7,186,143	507	0	31	1	3,776	135.43	0	6,957,008
Apr-10	5,751,946	300	0	30	1	3,777	135.79	0	5,885,103
May-10	5,955,445	191	11	31	1	3,777	136.14	0	5,828,409
Jun-10	5,593,546	85	8	30	0	3,777	136.50	0	5,547,860
Jul-10	6,583,421	5	63	31	0	3,777	136.86	0	6,307,013
Aug-10	6,579,397	41	79	31	0	3,777	137.22	0	6,725,491
Sep-10	5,631,042	239	0	30	1	3,777	137.58	0	5,715,308
Oct-10	6,099,363	313	0	31	1	3,776	137.94	0	6,265,327
Nov-10	7,293,701	525	0	30	1	3,776	138.31	0	6,961,015
Dec-10	9,387,908	974	0	31	0	3,776	138.67	0	9,511,659
Jan-11	9,814,872	1132	0	31	0	3,776	138.88	0	10,188,326
Feb-11	8,264,268	872	0	28	0	3,776	139.08	0	8,445,099
Mar-11	7,972,095	750	0	31	1	3,776	139.29	0	8,176,186
Apr-11	6,350,764	413	0	30	1	3,775	139.50	0	6,542,883
May-11	5,642,159	208	0	31	1	3,775	139.70	0	5,910,365
Jun-11	5,352,529	93	15	30	0	3,775	139.91	0	5,866,272
Jul-11	6,471,635	13	84	31	0	3,775	140.12	0	6,832,824
Aug-11	6,284,765	25	37	31	0	3,774	140.33	0	6,161,855
Sep-11	5,538,247	182	9	30	1	3,774	140.54	0	5,758,395
Oct-11	5,976,736	306	6	31	1	3,774	140.75	0	6,465,229
Nov-11	6,943,826	585	0	30	1	3,773	140.96	0	7,338,203
Dec-11	8,414,405	788	0	31	0	3,773	141.17	0	8,841,132

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	Number of Customers	Ontario Real GDP Monthly %	2012 Flag	Predicted Purchases
Jan-12	8,727,109	876	0	31	0	3,773	141.35	1	8,699,666
Feb-12	7,633,417	744	0	29	0	3,772	141.54	1	7,716,167
Mar-12	6,730,943	445	3	31	1	3,772	141.73	1	6,521,385
Apr-12	5,894,180	396	0	30	1	3,772	141.91	1	6,064,779
May-12	5,346,984	187	5	31	1	3,771	142.10	1	5,477,817
Jun-12	5,626,698	45	29	30	0	3,771	142.29	1	5,470,784
Jul-12	6,620,914	1	96	31	0	3,770	142.48	1	6,542,364
Aug-12	5,921,709	57	26	31	0	3,769	142.67	1	5,699,407
Sep-12	5,253,287	218	4	30	1	3,767	142.86	1	5,407,319
Oct-12	6,277,895	428	0	31	1	3,766	143.04	1	6,453,718
Nov-12	7,277,979	624	0	30	1	3,765	143.23	1	7,068,219
Dec-12	8,826,989	933	0	31	0	3,764	143.42	1	9,016,477
Jan-13		1017	0	31	0	3,763	143.60	1	9,374,686
Feb-13		862	0	28	0	3,762	143.78	1	8,072,611
Mar-13		655	0	31	1	3,760	143.96	1	7,442,747
Apr-13		384	0	30	1	3,759	144.14	1	6,082,810
May-13		226	5	31	1	3,758	144.32	1	5,706,169
Jun-13		77	22	30	0	3,757	144.50	1	5,557,297
Jul-13		27	60	31	0	3,756	144.67	1	6,152,376
Aug-13		53	37	31	0	3,754	144.85	1	5,922,089
Sep-13		164	12	30	1	3,753	145.03	1	5,359,109
Oct-13		370	1	31	1	3,752	145.21	1	6,285,813
Nov-13		583	0	30	1	3,751	145.39	1	6,957,080
Dec-13		898	0	31	0	3,750	145.58	1	8,927,131
Jan-14		1017	0	31	0	3,749	145.85	1	9,437,668
Feb-14		862	0	28	0	3,747	146.13	1	8,140,583
Mar-14		655	0	31	1	3,746	146.41	1	7,515,725
Apr-14		384	0	30	1	3,745	146.68	1	6,160,809
May-14		226	5	31	1	3,744	146.96	1	5,789,204
Jun-14		77	22	30	0	3,743	147.24	1	5,645,383
Jul-14		27	60	31	0	3,742	147.52	1	6,245,494
Aug-14		53	37	31	0	3,740	147.80	1	6,020,255
Sep-14		164	12	30	1	3,739	148.08	1	5,462,338
Oct-14		370	1	31	1	3,738	148.36	1	6,394,120
Nov-14		583	0	30	1	3,737	148.64	1	7,070,480
Dec-14		898	0	31	0	3,736	148.92	1	9,045,641

OPERATING REVENUE VARIANCE ANALYSIS

THROUGHPUT REVENUE and OTHER OPERATING REVENUE

VARIANCE ANALYSIS ON THROUGHPUT REVENUE:

A summary of historical and forecast operating revenues is presented in Exhibit 3, Tab 1. FFPC's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2012-0083 Decision and Order dated April 4, 2013 for 2013 information. Throughput revenue does not include commodity-related revenue.

A variance analysis for all factors, consumption, customer count and the resulting net operating revenue will be provided in the tables below:

Table 3.3.1: **Variance Analysis of Historic, Actual and Bridge and Test Year Consumption:**

Variance Analysis of Consumption in kWh	2006 Board Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Residential	38,358,635	38,674,263	40,986,845	40,872,765	40,921,847	38,642,702	38,681,251	37,169,840	37,551,665	37,751,518
General Service 50 kW	21,884,534	15,350,875	15,178,972	15,341,926	15,681,898	15,009,183	15,033,140	14,736,725	14,200,992	13,617,679
General Service 50 kW	20,657,710	27,269,745	26,441,963	25,476,812	24,920,577	25,386,687	24,978,251	23,898,102	25,160,587	26,376,324
Street Lighting	1,191,139	1,061,383	1,270,115	1,179,263	1,014,240	1,158,527	1,162,298	1,108,600	765,211	366,947
Unmetered Loads		192,228	175,428	75,264	70,728	64,814	62,628	62,628	55,151	48,552
Total	**82,092,018**	**82,548,494**	**84,053,323**	**82,946,030**	**82,609,290**	**80,261,913**	**79,917,568**	**76,975,895**	**77,733,606**	**78,161,019**
% Change (year over year)		**0.56%**	**1.82%**	**-1.32%**	**-0.41%**	**-2.84%**	**-0.43%**	**-3.68%**	**0.98%**	**0.55%**
% Change (Test Year vs Last Rebasing-Actual)										**-4.79%**

FFPC's consumption levels are gradually declining due to CDM results and a reduction in the population in the Town of Fort Frances. The Street Light LED retrofit notably reduced consumption to one-third of the original consumption. An unseasonably warm winter in 2012 reduced consumption when compared to 2011. A reallocation of General Service >50kW customers to the proper General Service >50kW rate class shifted the 2006 Board Approved consumption between the two rate classes.

Table 3.3.2: Variance Analysis of Historic, Actual and Bridge and Test Year Customer Numbers:

Variance Analysis of Customer Numbers	2006 Board Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Residential	3,383	3,380	3,332	3,305	3,309	3,307	3,308	3,308	3,299	3,290
General Service< 50 kW	485	437	438	426	418	419	421	417	411	405
General Service> 50 kW	43	47	47	49	47	51	46	46	47	47
Street Lighting	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006
Unmetered Loads		8	7	6	6	6	6	6	6	6
Total	**4,917**	**4,878**	**4,830**	**4,792**	**4,786**	**4,789**	**4,787**	**4,783**	**4,769**	**4,754**
% Change (year over year)		**-0.79%**	**-0.98%**	**-0.79%**	**-0.13%**	**0.06%**	**-0.04%**	**-0.08%**	**-0.30%**	**-0.30%**
% Change (Test Year vs Last Rebasing-Actual)										**-3.31%**

An overestimation of the General Service <50 kW in the Board Approved 2006 EDR rates is the notable variance in this review. A gradual decline in customer numbers of approximately 2% over an eight year period is due to the declining employment opportunities with the Town of Fort Frances.

Table 3.3.3: Variance Analysis of Historic, Actual & Bridge and Test Year Customer Operating Revenue

Variance Analysis of Operating Revenue	2006 Board Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Residential	$ 781,395	$ 730,372	$ 755,388	$ 800,223	$ 817,131	$ 814,357	$ 826,372	$ 798,002	$ 825,328	$ 807,947
General Service< 50 kW	$ 292,673	$ 207,434	$ 233,102	$ 237,718	$ 183,735	$ 231,057	$ 246,489	$ 243,272	$ 246,882	$ 230,282
General Service> 50 kW	$ 289,365	$ 301,831	$ 332,615	$ 327,048	$ 352,042	$ 371,847	$ 352,093	$ 345,959	$ 338,352	$ 369,062
Streetlights	$ 21,534	$ 21,754	$ 28,705	$ 16,049	$ 22,951	$ 23,229	$ 23,838	$ 23,984	$ 24,106	$ 17,343
Unmetered Loads		$ 3,235	$ 2,918	$ 2,171	$ 2,406	$ 2,320	$ 2,498	$ 2,510	$ 2,527	$ 2,411
Total	**$1,384,967**	**$ 1,264,626**	**$ 1,352,728**	**$1,383,209**	**$1,378,265**	**$1,442,810**	**$ 1,451,290**	**$ 1,413,727**	**$ 1,437,195**	**$ 1,427,045**
% Change (year over year)		**-8.69%**	**6.97%**	**2.25%**	**-0.36%**	**4.68%**	**0.59%**	**-2.59%**	**1.66%**	**-0.71%**
% Change (Test Year vs Last Rebasing-Actual)										**3.04%**

The 2006 Board Approved Revenue Requirement from Distribution Rates of $1,384,965 was not reached until the 2008 rate year. The difference between the Board Approved 2006 and the 2006 Actual totaled a reduction of $120,341, or -8.69%. The variance between Board Approved and 2014 Test Year revenue is an increase of 3.04%.

2006 Board Approved vs 2006 Actual:

FFPC is a winter peaking LDC and the winter of 2006 was warmer and the first quarter LDC consumption was 24,986,924 kWhs, versus 26,128,00 kWHs first quarter usage in 2004 and 2005. This created a drop in heating load and Residential and General Service <50 kW rate class revenue.

2006 Actual vs. 2007 Actual:

Revenues increased in 2007 as the consumption increased from 86,305,341 kWh to 87,693,969 kWh, an increase of 1.6 %. FFPC's February 2007 consumption increased to 9,228,910 kWh from 8,433,483 kWh in February 2006; an increase of almost 800,000 kWh. Billing adjustments for Street Lighting increase revenue in 2007 and creates a drop in 2008.

2007 Actual vs. 2008 Actual:

Consumption in 2007 and 2008 remained constant and customer rate increases in both fixed and variable distribution rates increased revenue despite declining customer numbers.

2008 Actual vs. 2009 Actual:

Consumption, customer numbers and revenues are unchanging from prior year.

2009 Actual vs. 2010 Actual:

Although consumption decreased overall in 2010, the months of July and August increased consumption and demand due to air conditioning load.

2010 Actual vs. 2011 Actual:

Consumption, demand and revenues are almost identical to 2010.

2011 Actual vs. 2012 Actual:

Decreased consumption has reduced revenues and Residential consumption has declined by 1.5 MWh due to conservation efforts, rental vacancies and an aging demographic.

2012 Actual vs. 2013 Bridge:

FFPC expects to reach projected consumption and revenue levels. Year to date (October) consumption is 2.6% greater than 2012 year to date, resulting in a slight increase in revenue.

2013 Bridge vs. 2014 Test

The load forecast projected increase in consumption and the proposed rate charges will result in a 28.14% increase in revenue versus prior year. FFPC's proposed rates are necessary to maintain current customer service levels, attract and hire additional staff to adjust to industry demands and workloads. FFPC, as a not for profit LDC, has deferred prior rate increases and the average increase over the rate period since the 2006 EDR is 3.63% annual increase.

TRANSFORMER ALLOWANCE

FFPC currently provides a Transformer Ownership Allowance Credit of $0.60 per kW of demand per month for all customers who own their own transformer facilities.

FFPC is proposing to maintain the rate of $0.60 per kW of demand per month for the 2014 Test Year for eligible customers.

SPECIFIC SERVICE CHARGES

FFPC last COS Application was 2006 EDR EB-2005-0366 and FFPC's Specific Service Charges have been unchanged since de-regulation. FFPC is proposing a review to properly adjust the current charges to reflect current business practices and to recover current costs.

Below in Table 3.3.12 are the current and proposed Specific Services Charges effective April 30, 2014.

SPECIFIC SERVICE CHARGES - Effective May 1, 2013	May 1, 2013 Existing		**May 1, 2014 Proposed**		
Customer Administration	Metric	Current	**Metric**	**Current**	
Arrears certificate	$	15.00	$	15.00	
Statement of account	$	15.00	$	15.00	
Pulling post dated cheques	$	15.00	Remove-unused		
Duplicate invoices for previous billing	$	15.00	$	15.00	
Request for other billing information	$	15.00	$	15.00	
Easement letter	$	15.00	$	15.00	
Income tax letter	$	15.00	$	15.00	
Notification charge	$	15.00	Remove-unused		
Account history	$	15.00	$	15.00	
Credit reference/credit check (plus credit agency costs)	$	15.00	$	25.00	Revised
Returned cheque charge (plus bank charges)	$	15.00	$	25.00	Revised
Charge to certify cheque	$	15.00	Remove-unused		
Legal letter charge	$	15.00	$	15.00	
Account set up charge/change of occupancy charge (plus credit agency costs if appl	$	15.00	$	30.00	Revised
Special meter reads	$	30.00	$	30.00	
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	$	30.00	
	$				
Non-Payment of Account	Metric	Current	Metric	Current	
Late Payment - per month	%	1.5	%	1.5	
Late Payment - per annum	%	19.56	%	19.56	
Collection of account charge - no disconnection	$	30.00	Remove-unused		
Collection of account charge - no disconnection - after regular hours	$	165.00	Remove-unused		
Disconnect/Reconnect at meter - during regular hours	$	20.00	$	65.00	Revised
Disconnect/Reconnect at meter - after regular hours	$	185.00	$	185.00	
Disconnect/Reconnect at pole - during regular hours	$	45.00	$	185.00	Revised
Disconnect/Reconnect at pole - after regular hours	$	415.00	$	415.00	
	$				
Other	Metric	Current	Metric	Current	
Install/Remove load control device - during regular hours	$	65.00	$	65.00	
Install/Remove load control device - after regular hours	$	185.00	$	185.00	
Service call - customer-owned equipment	$	30.00	$	65.00	Revised
Service call - after regular hours	$	165.00	$	165.00	
Temporary service install & remove - overhead - no transformer	$	500.00	Remove-unused		
Temporary service install & remove - underground - no transformer	$	300.00	Remove-unused		
Temporary service install & remove - overhead - with transformer	$	1,000.00	Remove-unused		
Specific Charge for Access to the Power Poles $/pole/year	$	22.35	$	22.35	

FFPC would like to remove the following specific charges not used within the last ten years:

FFPC requests the removal of all 'Temporary service install & remove-..,' charges. These charges were seldom used and not specific enough to recover costs from various types of temporary service installation. FFPC has recovered these costs in the past through the recoverable work charges (4325) and to directly bill for labour and truck hours and overheads, as each installation site is cost specific.

SPECIFIC SERVICE CHARGES - Removal Requested	May 1, 2013		May 1, 2014
	Metric	Current	Proposed Action
Pulling post dated cheques	$	15.00	Remove-unused
Notification charge	$	15.00	Remove-unused
Charge to certify cheque	$	15.00	Remove-unused
Collection of account charge - no disconnection	$	30.00	Remove-unused
Collection of account charge - no disconnection - after regular hours	$	165.00	Remove-unused
Temporary service install & remove - overhead - no transformer	$	500.00	Remove-unused
Temporary service install & remove - underground - no transformer	$	300.00	Remove-unused
Temporary service install & remove - overhead - with transformer	$	1,000.00	Remove-unused

FFPC finds it necessary to increase the following specific charges:

SPECIFIC SERVICE CHARGES - Proposal	May 1, 2013		May 1, 2014		
	Existing		Proposed		
Credit reference/credit check (plus credit agency costs)	$	15.00	$	25.00	Revised
Returned cheque charge (plus bank charges)	$	15.00	$	25.00	Revised
Account set up charge/change of occupancy charge (plus credit agency costs if appl	$	15.00	$	30.00	Revised
Disconnect/Reconnect at meter - during regular hours	$	20.00	$	65.00	Revised
Disconnect/Reconnect at pole - during regular hours	$	45.00	$	185.00	Revised
Service call - customer-owned equipment	$	30.00	$	65.00	Revised

FFPC proposes the increases to 'Credit reference/credit check', 'Returned cheque charge' and 'Account set up charge' to adjust these charges to true cost of providing service. FFPC's contracted labour rate has an end cost (labour plus benefits) of $35/hour. The time required to perform the service for:

- Credit Reference/credit check: 40-45 minutes x $35/per hour = $23.33-$26.25 = ± $25.00
- Returned cheque charge: 40-45 minutes x $35/per hour = $23.33-$26.25 = ± $25.00
- Account Set Up charge: 50-55 minutes x $35/per hour = $29.17-$32.08 = ± $30.00

The services above require ample time to respond to FFPC's customer focus requests and needs.

The 'Disconnect/Reconnect at meter' and 'Disconnect/Reconnect at pole' charges have been increased to reflect the true costs of performing this service, as described below:

- Disconnect/Reconnect at meter – during regular hours- $65.00
  The present lineman hourly cost in approximately $45 per hour and a basic vehicle cost is $20 per hour. Average time to complete work- 1 hour
- Disconnect/Reconnect at pole- during regular hours- Using the present linesman cost of $45 per hour and a bucket or service truck cost of $50 per hour. Average time to complete work – 1.3hrs - 2 lineman at $45 + truck at $50 = $130 per hour at 1.3 hrs = $182.00 ≤ **$185.00**

Table 3.3.12: Proposed Specific Service Charge Tariff

SPECIFIC SERVICE CHARGES - Effective May 1, 2013	May 1, 2014 Proposed	
Customer Administration	**Metric**	**Current**
Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	25.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if appl	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account	Metric	Current
Late Payment - per month	%	1.5
Late Payment - per annum	%	19.56
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Other	Metric	Current
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call - customer-owned equipment	$	65.00
Service call - after regular hours	$	165.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

OTHER OPERATING REVENUE/OTHER INCOME/DEDUCTIONS, INVESTMENT INCOME

USoA #	USoA Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Actual	Bridge Year 2013	Bridge Year 2013	Test Year 2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP	MIFRS	MIFRS
4235	Specific Service Charges	$ 8,411	$ 11,342	$ 20,662	$ 21,040	$ 29,751	$ 8,953	$ 9,003	$ 9,003	$ 9,000	$ 9,000	$ 9,849
4225	Late Payment Charges	$ 15,340	$ 20,067	$ 20,053	$ 21,922	$ 24,747	$ 23,669	$ 27,178	$ 27,178	$ 24,000	$ 24,000	$ 25,000
4082	Retail Services Revenues			$ 1,367	$ 1,623	$ 1,553	$ 540	$ 3	$ 3			
4084	Service Transactions Req				$ 1,475	$ 1,475	$ 1,130	$ 583	$ 583			
4086	SSS Admin Revenue							$ 10,906	$ 10,906	$ 11,332	$ 11,332	$ 11,184
4210	Electric Property-Rent	$ 37,831	$ 55,011	$ 42,936	$ 44,484	$ 47,328	$ 46,784	$ 47,162	$ 47,162	$ 48,000	$ 48,000	$ 48,000
4230	Sales of Water & Power							$ 12,419	$ 12,419	$ 5,000	$ 5,000	
4245	Govern Assist Direct Income						$ 1,120	$ 1,120	$ 1,120			
4324	Special Purpose Recovery					$ 18,810	-$ 1,068					
4325	Rev from Merchandise	$ 38,201	$ 38,349	$ 38,752	$ 57,462	$ 73,454	$ 54,814	$ 37,235	$ 37,235	$ 45,000	$ 45,000	$ 25,000
4330	Exp from Merchandise	-$ 37,684	-$ 38,259	-$ 37,782	-$ 47,333	-$ 45,116	-$ 51,346	-$ 33,835	-$ 33,835	-$ 41,500	-$ 41,500	-$ 21,000
4355	Gain on Disposition	$ 35,000	$ 2,390				$ 5,127			$ 15,000	$ 13,500	
4360	Loss on Disposition					-$ 1,220						
4375	Rev from Non-Utility	$ 7,431	$ 60,017	$ 60,017	$ 53,926	$ 134,362	$ 38,484	$ 36,971	$ 36,971	$ 45,000	$ 45,000	$ 45,000
4380	Exp from Non-Utility	-$ 7,204	-$ 59,517	-$ 59,517	-$ 43,635	-$ 116,887	-$ 36,059	-$ 36,522	-$ 36,522	-$ 40,000	-$ 40,000	-$ 40,000
4385	Non-Utility Rental					$ 27,328	$ 22,949	$ 1,673	$ 1,673			
4390	Misc Non Operating Income	$ 11,400	$ 20,815	$ 16,318	$ 22,495		$ 28,397					
Specific Service Charges		$ 8,411	$ 11,342	$ 20,662	$ 21,040	$ 29,751	$ 8,953	$ 9,003	$ 9,003	$ 9,000	$ 9,000	$ 9,849
Late Payment Charges		$ 15,340	$ 20,067	$ 20,053	$ 21,922	$ 24,747	$ 23,669	$ 27,178	$ 27,178	$ 24,000	$ 24,000	$ 25,000
Other Operating Revenues		$ 37,831	$ 55,011	$ 44,303	$ 47,582	$ 50,355	$ 49,574	$ 72,192	$ 72,192	$ 64,332	$ 64,332	$ 59,184
Other Income or Deductions		$ 47,144	$ 23,795	$ 17,788	$ 42,915	$ 90,731	$ 61,297	$ 5,523	$ 5,523	$ 23,500	$ 22,000	$ 9,000
Total		$ 108,726	$ 110,215	$ 102,806	$ 133,459	$ 195,584	$ 143,494	$ 113,896	$ 113,896	$ 120,832	$119,332	$ 103,033

OVERVIEW

FFPC's service revenue requirement for the purposes of this application is $1,965,3879 and the base revenue requirement is $1,862,354. The materiality threshold used to analyze Other Operating Revenue accounts in accordance with the Filing Requirements is $50,000 for distributors with a distribution revenue requirement less than or equal to $10 million.

FFPC will, however, describe variances that are below the materiality threshold in order to provide a meaningful analysis of the activity in the Other Operating Revenue accounts, as follows:

Miscellaneous Service Revenues

Miscellaneous Service Revenue has remained relatively constant from 2010 to forecast 2014. FFPC expects a slight decline in Late Payment Charges as continued efforts have be made to assist customers with proper arrears management.

Account 4375: Revenues from Non-Utility Operations
Account 4380: Expenses from Non-Utility Operations

Revenues and expenses from Non-Utility Operations increased in 2010 and 2011 due to the OPA Conservation Programs and the Community Initiatives Funding. FFPC is expected to complete its CDM targets in 2013 and reduced accounts levels for this reason.

Account 4080: Standard Supply Service Charge

The standard supply service charge has remained constant over the years 2010 to 2012. 2013 and 2014 will not see an increase due to the static customer numbers.

Account 4210: Rent from Electric Property

Rent from Electric Property has remained constant due to unchanged joint use pole counts.

Account 4225: Late Payment Charges

Late Payment Fees paid by customers on overdue accounts are expected to decrease slightly from 2012 levels due to enhanced collection efforts made by existing FFPC staff.

Account 4357: Gain on Retirement of Utility and Other Property

FFPC expects to realize a gain on the disposal a large trucks in 2013. No gains are expected to be recovered in 2014. An adjustment to the gain under MIFRS was to adjust for the cost of sale, etc.

Interest and Dividend Income

Account 4405 - Interest and Dividend Income

	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
					2013	2013	2014
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**CGAAP**	**MIFRS**	**MIFRS**
Short-term Investment Interest							
Bank Deposit Interest	$ 43,599	$ 60,746	$ 45,796	$ 38,933	$ 48,000	$ 48,000	$ 48,000
Miscellaneous Interest Revenue							
Regulatory Carrying Charges		$ 66,091		$ 6,863			
Total	$ 43,599	$ 126,837	$ 45,796	$ 45,796	$ 48,000	$ 48,000	$ 48,000

Interest income has increased in 2011 due to the increase in interest revenues as a result of regulatory asset balances.

FFPC
FORT FRANCES POWER CORPORATION

Filing Number: EB-2013-0130
Filed: December 20, 2013

EXHIBIT FOUR

OPERATING COSTS

Exhibit	Tab	Schedule	Appendix	Contents
4 – Operating Costs				
	1			**Overview**
		1		Manager's Summary of Operating Costs
	2			**OM&A Costs**
		1		Departmental and Corporate OM&A Activities
		2		OM&A Detailed Costs Tables
		3		Variance Analysis on OM&A Costs
		4		Employee Compensation
		5		Charges to Affiliates for Services Provided
		6		Purchase of Products and Services from Non-Affiliates
	3			**Depreciation, Income Tax, Large Corporation Tax**
		1		Depreciation, Amortization and Depletion
		2		Tax Calculations
		3		Capital Cost Allowance (CCA)
	4			**MIFRS Conversion**
		1		MIFRS Future Impact on OM&A, Depreciation
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	5	1		**Integrity Check List**
				Appendices
			A	FFPC's Purchasing Policy
			B	2012 Federal & Ontario Tax Returns
			C	Asset Retirement Obligation Position Paper
			D	PILs Model- PDF Version

OVERVIEW:

MANAGER'S SUMMARY OF OPERATING COSTS

The operating costs presented in this Exhibit represent the annual expenditures required to sustain FFPC's distribution operations. FFPC follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. FFPC has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. FFPC has moved our capitalization policy to be consistent with CGAAP and has applied deprecation rates consistent with the Kinectric's study but adjusted, when necessary, to reflect FFPC's Asset Management Policy. Upon the advice of our auditors, BDO Canada LLP, FFPC will defer the transition to IFRS until the Accounting Standards Board (AcSB) has made a final decision on whether rate-regulated entities will actually be required to adopt, which currently has been deferred until January 1, 2015.

FFPC has included one-time costs associated with consulting and legal costs used to prepare this application. FFPC's audited financial statements for the years 2010, 2011 and 2012 included only minor charitable contributions.

FFPC's business environment has undergone significant change during the eight year period since the last Board Approved 2006 EDR rate application. During this period, FFPC continued a cost conservative 'wait and see' approach with regard to new staffing, operational and capital investments. Although FFPC adapted well to the demands of industry, regulatory and political stakeholders, FFPC realizes it is no longer financially viable under its current business model without the degradation of performance indicators and customer service.

Current management and non-union staff have assumed a higher level of 'jobs per person' instead of 'persons per job' work status and are at risk of health-related job stress, with extended overtime and restricted personal time off. Developmental and industry training conferences are neglected due to sustained, prohibitive work load. Work flow efficiencies are lost as key employees are forced to refocus on shifting work demands.

Currently the President, CEO is responsible for the following duties beyond the typical CEO management umbrella that include the:

- Direct supervision and execution of Customer billing, including billing schedules, collection of accounts and business processes of FFPC's contracted staff;
- All activities under the Green Energy Act, including the day-to-day interface with customers and contractors regarding OPA initiatives and settlement for these activities;
- Customer metering and Smart Meter ODS operations and system enhancements,
- All activities relating to 'customer engagement' including trade shows, job fairs, surveys;
- Creation and maintenance of FFPC's Asset Management Policy and Distribution System Plan. Both documents underpin the long range capitalization path of FFPC to ensure reliability, continued efficiencies and a renewed focus on customer driven initiatives. The upkeep of these working documents is currently undesignated:
- Most significantly, the executive management of the 1905 Historic Mill Agreement held between the Town of Fort Frances and the holder of the generation assets, currently H2O Power LP (H2O), total value estimated at $2.2 Million annually. This includes the safe guarding of this agreement by ensuring regulatory and policy changes do not negate the benefit of the 1905 Agreement and enforcing the 1905 Agreement as against the various owners, from time to time, of the generation assets tied to the 1905 Agreement, in conjunction with FFPC's Board of Directors and legal counsel.

The CEO has worked an estimated annual overtime of 200 hours per year each non-rebasing year and estimated 400 hours to complete the COS application. More importantly, the primary role of this position, which is the planning and management of FFPC, has been neglected in order to complete the additional duties detailed above.

The CEO has also been unable to fully utilize earned personal time off benefits and there is a potential for work related stress issues. The CEO does not have temporary relief for work related and/or personal time off. This situation increases the responsibility of this position in that time off directly impacts work performance as the temporary designation of duties is unavailable.

Currently the Finance and Regulatory Officer is responsible for the following duties outside of the typical regulatory job scope:

- Operation and maintenance of FFPC's customer billing rate tariff, including the oversight of customer billing accuracy, rate classifications and IT rate changes;
- Interaction with consultants and customers regarding new installations, energy saving initiatives and complex billing adjustments and reviews;
- Oversight of all Retailer activities within the LDC service territory;
- Most significantly, the financial operation and execution of the 1905 Historic Power Agreement, held between the Town of Fort Frances and the holder of the generation assets, currently H2O Power LP (H2O), total value estimated at $2.2 Million annually. These additional duties account for one-third of this position (650 hours annually). These duties include:
    - Daily extraction of IESO settlement data by which a Physical Bilateral Contract (PBC) is used to redirect financial charges to H2O from FFPC;
    - The compilation of financial data from all sources and the execution of regulatory and accounting policy changes that may alter the agreement;
    - The alteration of FFPC's regulatory accounting to reflect the agreement through the Cost of Power accounts, settlement with IESO and account mapping of charges;
    - The disbursement of customer benefits through monthly credits and annual rebates and the unique billing and bill print challenges that arise. The review of eligibility, execution and return of customer rebates due to changes in account, family and retailer status;
    - Responding to stakeholder review. FFPC has completed two extensive audit reviews by Board staff that focused on the scope and execution of the 1905 Mill Agreement within the current regulatory accounting and reporting environment.

The Finance and Regulatory works an average of 150 hours of overtime annually. No temporary relief is available for this position and this amplifies the workload and stress with this position. All current personal time-off is scheduled around all work demands without regard to personal commitments and needs. This overtime required to complete this COS application is estimated to be 400 hours.

This position is expected to become vacant within a four year period and, due to the complexity and uniqueness of the duties within, FFPC will incur a cost to provide extended training for this position.

FFPC will, further in this application, outline the steps necessary to maintain current customer service levels and capital structure.

Although the Town of Fort Frances is experiencing an economic recession due to the reduction in paper operations at Resolute Forest Products, the town's major employer, this current economic situation does not relieve FFPC of its obligation to provide excellent customer service and continued system reliability through dedicated capital planning and maintenance. This recessionary market has caused FFPC's customer numbers and consumption to decline but this has not reduced the overall costs of the LDC's operation.

A summary of FFPC's operating costs for 2006 Board Approved, 2007-2012 Actual, 2013 Bridge Year and the 2014 Test Year are reported in CGAAP. FFPC does not currently and has not in the past capitalized overheads.

Table 4.2.1 – Summary of OM&A Expenses:

	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
	Last Rebasing Year (2006 Board-Approved)	Last Rebasing Year (2006 Actuals)	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$ 142,165	$ 154,931	$ 167,586	$ 161,730	$ 194,356	$ 192,399	$ 195,697	$ 213,851	$ 209,500	$ 371,000
Maintenance	$ 106,651	$ 92,874	$ 113,833	$ 142,860	$ 130,396	$ 183,394	$ 169,076	$ 377,219	$ 213,000	$ 304,000
Billing and Collecting	$ 144,547	$ 237,343	$ 235,870	$ 254,460	$ 266,345	$ 265,204	$ 213,984	$ 255,946	$ 235,500	$ 268,000
Community Relations	$ 4,712	$ 62,599	$ 35,457	$ 21,187	$ 14,905	$ 8,805	$ 6,024	$ 5,978	$ 4,750	$ 37,150
Administrative and General	$ 603,271	$ 577,417	$ 612,906	$ 686,964	$ 710,557	$ 675,883	$ 717,211	$ 751,977	$ 763,500	$ 677,500
Total	**$ 1,001,346**	**$ 1,125,164**	**$ 1,165,652**	**$ 1,267,201**	**$ 1,316,559**	**$ 1,325,685**	**$ 1,301,992**	**$ 1,604,971**	**$ 1,426,250**	**$ 1,657,650**
%Change (year over year)			3.6%	8.7%	3.9%	0.7%	-1.8%	23.3%	-11.1%	16.2%

FFPC is proposing recovery of 2014 Test Year OM&A costs, excluding amortization, property taxes, PILs and Interest totaling $1,657,650.

A summary of the Recoverable OM&A variances as required by the Filing Requirements is provided in Tables 4.2.3 through 4.2.5. As noted above, no changes to the OM&A expenses are made on the transition from CGAAP to MCGAAP.

Table 4.2.3: Summary of Recoverable OM&A Expenses 2006 Board Approved to 2014

	Last Rebasing Year (2006 Board-Approved)	Last Rebasing Year (2006 Actuals)	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations	$ 142,165	$ 154,931	$ 167,586	$ 161,730	$ 194,356	$ 192,399	$ 195,697	$ 213,851	$ 209,500	$ 371,000
Maintenance	$ 106,651	$ 92,874	$ 113,833	$ 142,860	$ 130,396	$ 183,394	$ 169,076	$ 377,219	$ 213,000	$ 304,000
SubTotal	**$ 248,816**	**$ 247,805**	**$ 281,419**	**$ 304,590**	**$ 324,752**	**$ 375,793**	**$ 364,773**	**$ 591,070**	**$ 422,500**	**$ 675,000**
%Change (year over year)			13.6%	8.2%	6.6%	15.7%	-2.9%	62.0%	-28.5%	59.8%
%Change (Test Year vs Last Rebasing Year - Actual)										172.4%
Billing and Collecting	$ 144,547	$ 237,343	$ 235,870	$ 254,460	$ 266,345	$ 265,204	$ 213,984	$ 255,946	$ 235,500	$ 268,000
Community Relations	$ 4,712	$ 62,599	$ 35,457	$ 21,187	$ 14,905	$ 8,805	$ 6,024	$ 5,978	$ 4,750	$ 37,150
Administrative and General	$ 603,271	$ 577,417	$ 612,906	$ 686,964	$ 710,557	$ 675,883	$ 717,211	$ 751,977	$ 763,500	$ 677,500
SubTotal	**$ 752,530**	**$ 877,359**	**$ 884,233**	**$ 962,611**	**$ 991,807**	**$ 949,892**	**$ 937,219**	**$ 1,013,901**	**$ 1,003,750**	**$ 982,650**
%Change (year over year)			0.8%	8.9%	3.0%	-4.2%	-1.3%	8.2%	-1.0%	-2.1%
%Change (Test Year vs Last Rebasing Year - Actual)										12.0%
Total	**$ 1,001,346**	**$ 1,125,164**	**$ 1,165,652**	**$ 1,267,201**	**$ 1,316,559**	**$ 1,325,685**	**$ 1,301,992**	**$ 1,604,971**	**$ 1,426,250**	**$ 1,657,650**
%Change (year over year)			3.6%	8.7%	3.9%	0.7%	-1.8%	23.3%	-11.1%	16.2%

Table 4.2.4: Summary OM&A Expense Variances 2006 Board Approved to 2014 Test Year

FFPC completed the variance summary, modified by Board Staff, to include 2006-2014 years inclusive, with the variance of 2011 Actual vs. 2006 Actual, 2012 Actual vs. 2011 Actual, 2013 Bridge vs. 2012 Actual and 2014 Test vs. 2013 Bridge.

2006-2010:

	Last Rebasing Year (2006 Board-Approved)	Last Rebasing Year (2006 Actuals)	Variance 2006 BA – 2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals
Operations	$ 142,165	$ 154,931	-$ 12,766	$ 167,586	$ 161,730	$ 194,356	$ 192,399
Maintenance	$ 106,651	$ 92,874	$ 13,777	$ 113,833	$ 142,860	$ 130,396	$ 183,204
Billing and Collecting	$ 144,547	$ 237,343	-$ 92,796	$ 235,870	$ 254,460	$ 266,345	$ 265,204
Community Relations	$ 4,712	$ 62,599	-$ 57,887	$ 35,457	$ 21,187	$ 14,905	$ 8,805
Administrative and General	$ 603,271	$ 577,417	$ 25,854	$ 612,906	$ 686,964	$ 710,557	$ 675,883
Total OM&A Expenses	$ 1,001,346	$ 1,125,164	-$ 123,818	$ 1,165,652	$ 1,267,201	$ 1,316,559	$ 1,325,685
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)							
Total Recoverable OM&A Expenses	$ 1,001,346	$ 1,125,164	-$ 123,818	$ 1,165,652	$ 1,267,201	$ 1,316,559	$ 1,325,685
Variance from previous year							
Percent change (year over year)							
Percent Change: Test year vs. Most Current Actual							
Simple average of % variance for all years							
Compound Annual Growth Rate for all years							
Compound Growth Rate (2012 Actuals vs. 2006 Actuals)							

2011-2012 Actual, 2013 Bridge and 2014 Test

	2011 Actuals	Variance 2011 Actuals vs. 2006 Actuals	2012 Actual	Variance 2012 Actuals vs. 2011 Actuals	2013 Bridge Year	Variance 2013 Bridge vs. 2012 Actuals	2014 Test Year	Variance 2014 Test vs. 2013 Bridge
Operations	$ 195,697	$ 40,766	$ 213,851	$ 18,154	$ 209,500	-$ 4,351	$ 371,000	$ 161,500
Maintenance	$ 169,076	$ 76,202	$ 377,219	$ 208,143	$ 213,000	-$ 164,219	$ 304,000	$ 91,000
Billing and Collecting	$ 213,984	-$ 23,359	$ 255,946	$ 41,962	$ 235,500	-$ 20,446	$ 268,000	$ 32,500
Community Relations	$ 6,024	-$ 56,575	$ 5,978	-$ 46	$ 4,750	-$ 1,228	$ 37,150	$ 32,400
Administrative and General	$ 717,211	$ 139,794	$ 751,977	$ 34,766	$ 763,500	$ 11,523	$ 677,500	-$ 86,000
Total OM&A Expenses	$ 1,301,992	$ 176,828	$ 1,604,971	$ 302,979	$ 1,426,250	-$ 178,721	$ 1,657,650	$ 231,400
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)		$ -	$ 187,044	$ 187,044		-$ 187,044		$ -
Total Recoverable OM&A Expenses	$ 1,301,992	$ 176,828	$ 1,417,927	$ 115,935	$ 1,426,250	$ 8,323	$ 1,657,650	$ 231,400
Variance from previous year		$ 300,646		-$ 60,893		-$ 107,612		$ 223,077
Percent change (year over year)		27%		-4%		-8%		13%
Percent Change: Test year vs. Most Current Actual				99.59%				
Simple average of % variance for all years				-79.43%				7%
Compound Annual Growth Rate for all years								0.049626112
Compound Growth Rate (2012 Actuals vs. 2006 Actuals)				-31.53%				

The table below sets out the OM&A cost per customer and Full Time equivalent employees.

Table 4.2.5 – OM&A Per Customer and FTE

	Last Rebasing Year - 2006-Board Approved	Last Rebasing Year - 2006-Actual	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	3,981	3,981	3,864	4,001	3,768	3,777	3,775	3,780	3,769	3,749
Total Recoverable OM&A from Appendix 2-JB	$ 1,001,346	$ 1,125,164	$ 1,165,652	$ 1,267,201	$ 1,316,559	$ 1,325,685	$ 1,301,992	$ 1,604,971	$ 1,426,250	$ 1,657,650
OM&A cost per customer	$ 252	$ 283	$ 302	$ 317	$ 349	$ 351	$ 345	$ 425	$ 378	$ 442
Number of FTEs	8	8	8	9.3	9.7	9.3	9.3	9.3	9.3	10.1
Customers/FTEs	498	498	483	430	388	406	406	406	405	371
OM&A Cost per FTE	$ 125,168	$ 140,645	$ 145,706	$ 136,258	$ 135,728	$ 142,547	$ 139,999	$ 172,577	$ 153,360	$ 164,124

FFPC used the 'Total Customers' statistic from the OEB's annual Yearbook of Distributors for the years 2006-2012. The number of residential, GS<50 and GS>50 customers are adjusted to an estimated number of customers as at June 30th in each year to provide a mid-year value. The number of customers for the years 2013 and 2014 include the residential, GS<50 and GS>50 customers as found in FFPC's Load Forecast as set out in Exhibit 3.

The number of FTEEs includes both full time and part time employees. The part time employee calculation is based on the number of months worked during the year vs. the number of months a full time employee worked in each year.

<u>FFPC's Unique Situation and Impact on OM&A Costs</u>

FFPC's unique situation comes from the three main functional categories of operations provided for FFPC customers by the management of the:

- Local Distribution Company;

- Fort Frances Municipal Transformer Station (FFMTS);
- Historic Mill Agreement held between the owner of the generation assets and the Town of Fort Frances.

These three distinct functions provided by FFPC have considerable cost burdens in addition to normal costs borne by most LDCs. The two additional functions of operating FFMTS and, more significantly, the costs created by FFPC's stewardship of the 1905 Mill Agreement, is responsible for FFPC's higher OM&A costs, OM&A costs per customer, and higher FTE per customer ratios.

Detailed information with respect to OM&A costs, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 2. Detailed information with respect to OM&A variances, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 3.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements is $50,000 for a distributor with a distribution revenue requirement of less than or equal to $10 million. As FFPC's distribution revenue requirement is less than $10 million, details of variances over $50,000 will be provided. In addition, FFPC may provide other variance analysis on expenses less than $50,000 in order to be transparent in our analysis.

OM&A Costs:

OM&A costs in this Exhibit represent FFPC's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to

customers connected to FFPC's distribution system and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2014 Test Year are the result of a business planning and work prioritization process, based on FFPC's Asset Management Process (AMP) that ensures that the most appropriate, cost effective solutions are put in place.

OM&A Budgeting Process:

The operating budget is prepared annually by internal staff and management and is reviewed and approved by the Board of Directors. The budget is prepared in draft form prior to each fiscal year, and provides a plan against which actual results are evaluated. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget is approved by the Board of Directors.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Managerial staff provide input for the preparation of the annual budget. The following directives are reviewed during this process:

- All department budgets are built using previous year actual, current year forecast and current year budget as the base and incremental OM&A costs determined by FFPC's AMP are included in these projections;
- Significant variances in spending from prior years are reviewed and documented;
- Review staffing levels and succession planning or accuracy and outline any changes;
- Accounting staff prepares a total budget for the LDC using projected wage and benefit costs.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

FFPC is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Please refer to Exhibit 4, Tab 3, Schedule 1 and Appendix B for further tax calculations and a copy of the 2012 Federal tax return. FFPC has not paid tax since 2008 due to low accounting net income before taxes and apprenticeship tax credits.

FFPC has included one-time costs in the operating budget for legal and consulting costs related to regulatory matters.

Regulatory Costs:

Regulatory costs as indicated in the variance analysis are presented in Table 4.2.6(a). Regulatory costs for the 2014 rate application (estimated at $98,000) include FFPC's incremental staffing, consulting, and legal costs as well as anticipated Board and Intervenor expenses and are shown on Table 4.2.6(b). These costs have been spread over a five year period beginning with the 2014 OM&A budget (20% of actual 2014 expenses relating to the 2014 cost of service application are included in OM&A for 2014). The costs that have been included are indicated below:

Table 4.2.6(a) - Regulatory Costs

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2006 Board Approved)	Most Current Actuals Year 2012	2013 Bridge Year	Annual % Change	2014 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	H) = [(G)-(F)]/(F	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 4,380	$ 9,962	$ 10,000	0.38%	$ 10,000	0.00%
2	OEB Section 30 Costs (Applicant-originated)	5655				$ -				
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 326	$ 618	$ 1,000	61.81%	$ 1,000	0.00%
4	Expert Witness costs for regulatory matters	5655								
5	Legal costs for regulatory matters	5655								
6	Consultants' costs for regulatory matters	5630		On-Going		$ 3,295	$ 6,000	82.09%	$ 4,000	-33.33%
7	Operating expenses associated with staff resources allocated to regulatory matters	5610		On-Going	$ 4,877	$ 51,660	$ 70,560	36.59%	$ 36,120	-48.81%
8	Operating expenses associated with other resources allocated to regulatory matters [1] PILs Decision EB-2012-0083	5655		One-Time		$ 28,882		-100.00%		
9	Other regulatory agency fees or assessments	5655		On-Going	$ 800	$ 1,830	$ 2,000	9.29%	$ 3,000	50.00%
10	Any other costs for regulatory matters (please define)- Consultants for COS Application	5630-1255		One-Time			$ 30,000		$ 25,000	-16.67%
11	Intervenor costs	5655		One-Time		$ 2,334	$ 5,000	114.22%	$ 5,000	0.00%
12	Sub-total - Ongoing Costs [3]		$ -		$ 5,506	$ 18,039	$ 19,000	5.33%	$ 18,000	-5.26%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ 28,882	$ 105,560	265.49%	$ 66,120	-37.36%
14	Total		$ -		$ 5,506	$ 46,921	$ 124,560	165.47%	$ 84,120	-32.47%

Table 4.2.6(b) - Regulatory Costs – One-Time

		Historical Year(s)	2013 Bridge Year	2014 Test Year		
4	Expert Witness costs					
5	Legal costs					
6	Consultants' costs					
7	Incremental operating expenses associated with staff resources allocated to this application.		$ 18,000	$ 15,000		
8	Incremental operating expenses associated with other resources allocated to this application. Consultants[1]	$ -	$ 30,000	$ 25,000		
11	Intervenor costs		$ 5,000	$ 5,000	**Total Costs**	**Total/5 Years**
	Total		**$ 53,000**	**$ 45,000**	**$ 98,000**	**$ 19,600**

DONATIONS

Sub-account Low Income Assistance Program (LEAP)

FFPC has included $2,000 of expense for the Low Income Assistance Program (LEAP) under Collection Expenses (USoA #6205). This amount is based on 0.12% of the 2014 Test year Revenue Requirement, rounded. Based on a service revenue requirement of FFPC's LEAP commitment would remain at $2,000.

Charitable Contributions

FFPC has not included charitable donations or political contributions in addition to LEAP funding in OM&A expenses for 2014.

A history of FFPC's charitable donations is featured in the table below.

	Other Deductions	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
6205	Donations					$ 75	$ 2,034	$ 2,730	$ 2,000	$ 2,000

Green Energy Act

Exhibit 2 of this application provides FFPC's plan for capital spending under the Green Energy Act. FFPC has not included any operating expenses related to the Green Energy Act in this application. FFPC does intend to record any incremental operating expenses related to the Green Energy Act in the prescribed deferral account. BB: However, if such expenses do occur on a historical/actual basis FFPC may book these expenses to the prescribed deferral account and may seek recovery of these costs in a future application.

Inflation in 2013 Bridge and 2014 Test Year

The 2013 Bridge Year forecast is based on budgeted expenses for the year In the 2014 Test Year expenses have been budgeted based on estimated projected incomes and expenses.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5096) and maintenance (5105-5195) of FFPC's distribution system. This includes direct labour costs (labour, burden & benefits) and non-capital material spending to support both scheduled and reactive maintenance events. FFPC's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions. FFPC's emergency overtime hours are very low as a result of this strategy.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the distribution system. These activities include transformer oil analysis, planned visual inspections and pole testing. These evaluation results are all entered into FFPC's AMP records, where the attributes and conditions of all assets are assessed and a degradation score is used to predict 'end-of-life' dates. Any identified deficiencies found are prioritized and addressed within a suitable time frame. FFPC adheres to ESA Regulation 22/04 in regards to maintenance schedules and frequency of inspections.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of distribution components. This includes overhead and pad-mounted load break switch maintenance and cleaning/inspection of padmount vaults. Also included are regular inspection and repair of transformer station components and ancillary equipment. The work is performed using a combination of time and condition based methodologies. FFPC adheres to ESA Regulation 22/04 in regards to maintenance schedules and frequency of inspections.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. FFPC completes an annual tree trimming program to effectively eliminate emergency tree trimming. FFPC constantly evaluates its maintenance data to adjust predictive and preventative actions. An example is when, prior to 2009, FFPC realized that the majority of the emergency outage calls were the result of animal contact outages on primary lines. FFPC installed squirrel guards in 2009 and 2010 to greatly reduce this type of outage. The ultimate objective is to reduce all emergency maintenance. FFPC's "on call" lineperson carry a emergency dedicated cell phone and will notify supervisory staff of non-routine service problems outside of normal business hours.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (temporary disconnects for customer tree trimming, etc). This includes service disconnections and reconnections by FFPC line staff for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Network Control Operations:

FFPC does not own nor operate a Supervisory Control and Data Acquisition ("SCADA") system.

Metering:

Our line staff is responsible for the installation, testing, and commissioning of new and existing routine and complex metering installations. FFPC's line superintendent and CEO, an electrical engineer, assist with the planning of complex metering installations. FFPC replaced existing mechanical meters for all metered rate classes during the Smart Meter installation. Internal staff completed the more complex poly phase meter replacements to complete the transition. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by metering by proactively investigating any potential diversion and theft of power. An annual and spot-check reviews of all large general customers is completed by FFPC's Finance & Regulatory Officer to ensure accuracy and proper rate classification. FFPC is proposing, further in this exhibit, the hiring of additional technical staff to assume the care and control of FFPC's metering.

Transformer Station Services:

Transformer Station (TS) services activities address the maintenance of all equipment at FFPC's transformer station, "Fort Frances MTS" (Municipal Transformer Station), and is also known as 'FFMTS'. FFPC's distribution system does not utilize municipal distribution substations. The TS services include both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, transformer station maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of FFPC's planned maintenance program (including predictive and preventative actions) for its station.

Engineering Expenses

Existing FFPC staff complete design and drafting services for most capital projects and FFPC utilizes contracted services when needed. FFPC is seeking to improve the recording of its

distribution system asset information and is proposing additional staff funding to maintain our GIS system, AutoCAD, and system mapping.

Garage/Transportation Fleet

This category presently maintains and controls eight (8) fleet vehicles. Its objectives include keeping maintenance schedules to ensure vehicle reliability and safety and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and recoverable 'work for others' receivable accounts based on number of hours used. A standard "cost per hour" is set for all vehicles within the fleet determined by the vehicle's annual estimated operating cost per hour.

Labour Burden/Safety and Health

Safety and Health costs are collected within each department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. FFPC is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. FFPC's commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits, ensuring safe clothing and accessories; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. All FFPC staff members attend 'Forum North', an annual health and safety conference in Thunder Bay on a rotational basis.

CUSTOMER SERVICE

The contracted services from the Town of Fort Frances provide the majority of the customer care activities for the approximate 3,800 customers in Town of Fort Frances in FFPC's service area. These activities include special meter reading, billing, call centre, collections, and other back office functions.

FFPC aspires to achieve customer service excellence in all of its processes and customer programs. FFPC, in advance of this rate application, asked our customer base to complete a voluntary survey regarding the services provided by FFPC. The results indicate that of the 9.2% of FFPC's customer base that completed the survey, the average score for ranking the satisfaction level of FFPC's services was rated as a 9 out of a possible score of 10, or 'very satisfied'. The results of the survey and FFPC's response are explained in Exhibit 4, Tab 2, Schedule 6.

The costs associated with both contracted and internal customer service costs are reported in accounts 5305 to 5340.

FFPC contracts to the Town of Fort Frances the following services:

- Customer billing and collections;
- Accounting services
- Payroll services

The use of contracted services is both economical and efficient for FFPC. FFPC's business office is shared with Town of Fort Frances (TOFF) and is located on the lower level of the TOFF Civic Centre. These shared resources provide efficiencies for like services, such as IT support and phone systems, hydro and municipal service account management, payroll and accounting systems. The economies of scale within our community are fully utilized and TOFF staff resources provide a diverse support network for FFPC.

The contracted services provided by TOFF payroll staff collect the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments,

capital and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year based on the previous year's actual costs adjusted for known anomalies.

Meter Reading:

Prior to 2010, meter reading services were contracted out to the Town of Fort Frances under a service contract agreement. The transition to electronic meter reading was utilized for billing in 2010, in conjunction with TOU billing that commenced in January 2012. Meter reading services continue to be used for monthly billing of our GS>50 kW customers to reset demand readings.

Billing:

FFPC performs monthly billing and issues 46,000 electricity invoices annually to customers. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes (verification, estimation and edit); Electronic Billing Transactions (EBT) and retailer settlement functions for less than 80 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. FFPC offers customers a number of billing and payment options including walk-in counter service provided by our contract staff (Town of Fort Frances), an equal payment plan, a preauthorized payment plan and on-line credit card payments.

Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In an effort to minimize credit losses, FFPC enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. FFPC line staff use door tags to notify of pending non-payment disconnect. Final bill collections are turned over to a collection agency after collection methods are exhausted.

Community Relations:

FFPC is committed to providing consumer information and responses in a timely and proactive manner on electricity distribution and related issues. FFPC maintains a presence within the town, where staff are available to answer customer questions in a friendly environment. FFPC staff often field calls and inquiries from the neighbouring rural Hydro One customers that seek information regarding power interruptions, the connection of new services and generation programs available.

Since LDCs are the "face-to-the-customer" for the electricity industry, FFPC has an important role to play in educating the public about electricity safety and energy conservation. FFPC has participated actively in local trade shows, employment fairs and Christmas parades in prior years. However, FFPC has been unable to maintain a high level of participation in the last five years due to current staffing levels.

FFPC, in an effort to respond to the 'customer-centric approach' within our industry, strives to improve our participation in community events.

FFPC continues to participate with the OPA administered programs directed at Energy Conservation and is partnered with local contractors and the Town of Fort Frances's Sustainability Coordinator in achieving shared objectives. Currently these duties are completed by the President/CEO and FFPC is proposing a reassignment of these duties to a Technical Customer Service person.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within FFPC, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- Management Salaries and Expenses (5610)

Executive Salaries and Expenses: 5605

This account historically recorded the expenses for the remuneration and related expenses for FFPC's Board of Directors. In the 2013 Bridge year, these expenses were collected under the proper USoA account 5665. The expenses for the President and CEO are allocated to account 5605 in the 2014 Test year. There are no Board of Directors costs for affiliates included in the LDC costs.

Management Salaries and Expenses: 5610

Management Salaries and Expenses, 5610 collected the expenses of two employees; President and CEO and Line Superintendent. This legacy issue of reporting the Line Superintendent expenses under the Management umbrella has inflated FFPC's historic Management/Administration costs. These costs will be reallocated in the 2014 test year to the proper 5005 & 5105 accounts.

The President/CEO is responsible for the strategic planning, development, supervision, coordination, and leadership in the distribution of electrical services within the municipal boundaries of the Town of Fort Frances. In addition to those tasks, the CEO currently oversees FFPC's Customer Service activities, OPA customer generation and conservation programs. The reallocation of these duties is proposed further in this application.

Consistent with Section 6-4 of the 2006 EDR Handbook which states that… "In cases where there are three or fewer, full time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer FTEs." FFPC has the combined Management and Administrative Salaries, as both categories contain three or fewer FTEs.

General Administrative Salaries and Expenses: 5615

There are two FTE within this labour category. The Finance and Regulatory Officer performs all finance and revenue duties, including customer rate change/review, and customer classification. The regulatory duties performed are regulatory reporting and compliance with applicable codes and legislation governing FFPC, including development and preparation of rate filings, performance reporting, and compliance. The accounting, analysis and reporting of the Historic Mill Agreement is also a major responsibility within this position, and is unique and apart from all other rate-regulated activities.

An Administrative Assistant supports the CEO position and all other FFPC employees. This position is responsible for accounts payable, accounts receivable, customer payment plans, payroll preparation and office organization. The Administrative Assistant also administers customer disconnects, locates and work orders with Town of Fort Frances.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

Employee Post-Retirement Benefits: 5645

FFPC does not offer any post-retirement benefits to staff.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by

the OEB are included in this expenditure category. Further information regarding the projected costs of this application is addressed further in this exhibit.

FFPC regulatory costs to complete this Cost of Service application are estimated to be:

		Historical Year(s)	2013 Bridge Year	2014 Test Year		
4	Expert Witness costs					
5	Legal costs					
6	Consultants' costs					
7	Incremental operating expenses associated with staff resources allocated to this application.		$ 18,000	$ 15,000		
8	Incremental operating expenses associated with other resources allocated to this application. Consultants and Lawyers	$ -	$ 30,000	$ 25,000		
11	Intervenor costs		$ 5,000	$ 5,000	**Total Costs**	**Total/5 Years**
	Total		**$ 53,000**	**$ 45,000**	**$ 98,000**	**$ 19,600**

The main body of the COS application was completed by the Finance and Regulatory Officer, who is being compensated for incremental overtime work hours. Other incremental costs included in this application include consultant and legal fees and expenses, travel and meeting costs, intervenor costs and any cost required to complete the application. FFPC may seek additional legal counsel regarding the specific treatment of the Historic Mill agreement through this regulatory process.

Miscellaneous General Expense: 5665

Membership dues and other miscellaneous costs are included in this account. FFPC is a member of the Electricity Distributors Association and the Northwest Group. The Northwest Group has a membership of 5 LDCs. Within the Northwest group are Thunder Bay Hydro Electric Distribution, Kenora Hydro Electric Corporation Ltd., Sioux Lookout Hydro Inc., Atikokan Hydro Inc and FFPC, who have worked together on common issues which have been mutually beneficial to the members. These include shared metering and customer billing services (contracted from Thunder Bay Hydro), Smart Meter procurement, installation and security, CDM programs, joint training sessions and industry initiatives. As mentioned prior, the expenses for the Board of Directors fees and expenses are collected within this account , effective for the 2013 Bridge year.

Rent: 5670

Expenses under Rent include the costs of operating the Administrative office space that FFPC occupies on the lower level of the Town of Fort Frances Civic Centre. FFPC occupies the approximately one-half of the lower level of the Civic Centre, which house the office space for the President/CEO, Administrative Assistant and the Finance and Regulatory Officer. A conference room is the location for Board and training meetings. These shared costs are determined by a square foot percentage of occupied space divided into the total costs of operating the Civic Centre. These include items such as: building utility costs, maintenance & repairs to the office building, lawn care & snow removal. FFPC has an additional work centre located in the industrial park that provides a building for offices, inventory and line staff. Those costs are collected under account USoA 5085.

Electrical Safety Authority ("ESA"): 5680

Expenses under Electrical Safety Authority ("ESA") fees include all annual charges from the ESA as well as annual audit expenses.

OM&A DETAILED COSTS TABLES

Tables 4.2.7, 4.2.8, 4.2.9, 4.2.10 and 4.2.11 provide details of OM&A per USoA number for the years 2006 to 2012 Actual under CGAAP and forecasts for 2013 Bridge Year and 2014 Test Year under CGAAP.

Table 4.2.7: Detailed Account by Account Operation Expenses

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
	Distribution Expenses - Operation	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
5005	Operation Supervision and Engineering									$ 91,000
5010	Load Dispatching									
5012	Station Buildings and Fixtures Expense	$ 33,986	$ 34,349	$ 31,741	$ 46,329	$ 47,180	$ 45,775	$ 49,550	$ 50,000	$ 50,000
5014	Transformer Station Equipment - Operation Labour								$ 14,000	$ 14,000
5015	Transformer Station Equipment - Operation Supplies and	-							$ 10,000	$ 15,000
5016	Distribution Station Equipment - Operation Labour	$ 2,505	$ 2,807	$ 4,289	$ 6,387	$ 3,956	$ 6,020	$ 15,034		
5017	Distribution Station Equipment - Operation Supplies and	$ 8,622	$ 19,291	$ 9,298	$ 17,924	$ 6,068	$ 10,154	$ 11,651		
5020	Overhead Distribution Lines and Feeders - Operation Labo	$ 7,176	$ 12,539	$ 12,351	$ 14,783	$ 13,910	$ 9,764	$ 9,080	$ 13,000	$ 16,000
5025	Overhead Distribution Lines and Feeders - Operation Sup	$ 6,388	$ 6,710	$ 4,758	$ 1,086	$ 3,405	$ 73	$ 188		
5030	Overhead Subtransmission Feeders - Operation									
5035	Overhead Distribution Transformers - Operation	$ 5,674	$ 378		$ 47	$ 6,797	$ 1,309	$ 816	$ 1,000	$ 2,000
5040	Underground Distribution Lines and Feeders - Operation	$ 3,006	$ 2,440	$ 3,252	$ 12,118	$ 9,905	$ 9,472	$ 13,547	$ 10,000	$ 15,000
5045	Underground Distribution Lines and Feeders - Operation	$ 740	$ 1,234	$ 822	$ 3,807	$ 2,574	$ 2,251	$ 2,724		
5050	Underground Subtransmission Feeders - Operation						$ 81			
5055	Underground Distribution Transformers - Operation	$ 319				$ 797				
5060	Street Lighting and Signal System Expense									
5065	Meter Expense	$ 46,115	$ 38,251	$ 27,412	$ 18,932	$ 22,688	$ 36,325	$ 28,697	$ 28,000	$ 35,000
5070	Customer Premises - Operation Labour									$ 5,000
5075	Customer Premises - Materials and Expenses				$ 122			$ 595		
5085	Miscellaneous Distribution Expense-Includes GIS.	$ 40,400	$ 49,587	$ 67,808	$ 72,821	$ 75,119	$ 74,474	$ 81,970	$ 83,500	$ 128,000
	TOTAL	**$ 154,931**	**$ 167,586**	**$ 161,730**	**$ 194,356**	**$ 192,399**	**$ 195,697**	**$ 213,851**	**$ 209,500**	**$ 371,000**

Table 4.2.8: Detailed Account by Account Maintenance Expenses

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
	Distribution Expenses - Maintenance	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
5105	Maintenance Supervision and Engineering	$ 461	$ 104							$ 35,000
5110	Maintenance of Structures									
5112	Maintenance of Transformer Station Equipment								$ 30,000	$ 35,000
5114	Mtaint Dist Stn Equip	$ 11,420	$ 7,901	$ 19,803	$ 14,462	$ 35,111	$ 28,207	$ 31,624		
5120	Maintenance of Poles, Towers and Fixtures	$ 25,900	$ 25,944	$ 25,416	$ 16,269	$ 29,671	$ 11,835	$ 25,911	$ 30,000	$ 45,000
5125	Maintenance of Overhead Conductors and Devices	$ 24,365	$ 28,296	$ 31,169	$ 35,796	$ 43,466	$ 39,248	$ 39,980	$ 45,000	$ 58,000
5130	Maintenance of Overhead Services	$ 2,770	$ 4,644	$ 2,105	$ 3,735	$ 7,606	$ 9,156	$ 5,377	$ 6,000	$ 10,000
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 22,964	$ 45,818	$ 63,243	$ 52,441	$ 56,248	$ 75,245	$ 66,563	$ 60,000	$ 63,000
5145	Maintenance of Underground Conduit	$ 74		$ 1,125				$ 20,016	$ 5,000	$ 8,000
5150	Maintenance of Underground Conductors and Devices	$ 1,072	$ 1,070		$ 4,928	$ 8,209	$ 3,655	$ 116	$ 10,000	$ 12,000
5155	Maintenance of Underground Services				$ 597	$ 1,858	$ 887	$ 590		$ 4,000
5160	Maintenance of Line Transformers	$ 63	$ 55		$ 2,168	$ 1,225	$ 843		$ 1,000	$ 2,000
5165	Maintenance of Street Lighting and Signal Systems									
5175	Maintenance of Meters							$ 187,044	$ 26,000	$ 32,000
5195	Maintenance of Other Installations on Customer Premise	$ 3,785								
	TOTAL	**$ 92,874**	**$ 113,833**	**$ 142,860**	**$ 130,396**	**$ 183,394**	**$ 169,076**	**$ 377,219**	**$ 213,000**	**$ 304,000**

Table 4.2.9: Detailed Account by Account Billing & Collecting Expenses

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
	Billing and Collecting	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
5305	Supervision									
5310	Meter Reading Expense	$ 35,859	$ 33,508	$ 39,355	$ 42,332	$ 31,692	$ 8,774	$ 5,488	$ 6,000	$ 6,000
5315	Customer Billing	$ 117,697	$ 119,335	$ 125,851	$ 133,324	$ 130,232	$ 122,531	$ 146,109	$ 137,000	$ 160,000
5320	Collecting	$ 77,024	$ 79,772	$ 84,302	$ 89,010	$ 92,285	$ 76,854	$ 93,373	$ 84,500	$ 100,000
5325	Collecting - Cash Over and Short									
5330	Collection Charges									
5335	Bad Debt Expense	$ 6,763	$ 3,255	$ 4,951	$ 1,680	$ 10,996	$ 5,826	$ 10,976	$ 8,000	$ 8,000
5340	Miscellaneous Customer Accounts Expenses									
	TOTAL	$ 237,343	$ 235,870	$ 254,460	$ 266,345	$ 265,204	$ 213,984	$ 255,946	$ 235,500	$ 274,000

Table 4.2.10: Detailed Account by Account Community Relations Expenses

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
	Community Relations	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
5405	Supervision	$ 1,075								
5410	Community Relations - Sundry	$ 4,162	$ 4,772	$ 21,041	$ 14,720	$ 8,773	$ 6,024	$ 5,978	$ 4,750	$ 26,750
5415	Energy Conservation	$ 57,362	$ 30,686		$ 185	$ 32				$ 8,000
5420	Community Safety Program			$ 146						$ 2,400
5425	Miscellaneous Customer Service and Informational Expenses									
	TOTAL	$ 62,599	$ 35,457	$ 21,187	$ 14,905	$ 8,805	$ 6,024	$ 5,978	$ 4,750	$ 37,150

Table 4.2.11: Detailed Account by Account General & Administrative Expenses

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
	Administrative and General Expenses	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
5605-15	Salaries	$ 376,949	$ 423,227	$ 439,155	$ 496,049	$ 439,160	$ 445,624	$ 460,116	$ 484,500	$ 321,500
5620	Office Supplies and Expenses	$ 24,711	$ 16,677	$ 17,302	$ 16,854	$ 17,528	$ 19,576	$ 20,893	$ 20,000	$ 20,000
5625	Administrative Expense Transferred-Credit	$ (5,996)	$ (4,956)	$ (3,632)	$ (5,541)		$ (3,635)	$ (3,460)	$ (6,000)	$ (6,000)
5630	Outside Services Employed	$ 66,399	$ 75,127	$ 99,860	$ 53,822	$ 45,845	$ 55,089	$ 82,503	$ 60,000	$ 60,000
5635	Property Insurance	$ 13,133	$ 15,265	$ 15,231	$ 15,579	$ 14,447	$ 15,962	$ 15,855	$ 15,000	$ 15,000
5640	Injuries and Damages									
5645	Employee Pensions and Benefits	$ 64,266	$ 39,909	$ 63,329	$ 69,016	$ 70,999	$ 104,797	$ 80,942	$ 90,000	$ 90,000
5650	Franchise Requirements									
5655	Regulatory Expenses	$ 10,383	$ 5,907	$ 15,745	$ 9,825	$ 10,601	$ 25,855	$ 46,920	$ 40,000	$ 70,000
5660	General Advertising Expenses	$ 2,750	$ 4,885	$ 3,987	$ 2,827	$ 2,577	$ 5,322	$ 8,324	$ 8,000	$ 8,000
5665	Miscellaneous Expenses				$ 28,459	$ 52,514	$ 26,576	$ 17,004	$ 15,000	$ 62,000
5670	Rent	$ 13,284	$ 13,373	$ 13,284	$ 13,284	$ 13,284	$ 13,284	$ 13,284	$ 14,000	$ 14,000
5675	Maintenance of General Plant									
5680	Electrical Safety Authority Fees	$ 5,253	$ 17,206	$ 18,314	$ 5,724	$ 4,539	$ 4,371	$ 5,205	$ 5,300	$ 5,300
5685	Independent Market Operator Fees and Penalties	$ 6,285	$ 6,285	$ 4,389	$ 4,389	$ 4,389	$ 4,389	$ 4,389	$ 4,700	$ 4,700
5695	OM&A Contra Account				$ 271					
	TOTAL	$ 577,417	$ 612,906	$ 686,964	$ 710,557	$ 675,883	$ 717,211	$ 751,977	$ 750,500	$ 664,500

VARIANCE ANALYSIS ON OM&A COSTS:

FFPC has provided a detailed OM&A expense analysis covering the periods from FFPC's last cost of service application. An analysis of expense changes by cost driver approach is provided in Table 4.2.12 with explanations below, based on the Chapter 2 Appendices, Sheet App 2-JB;

Table 4.2.12: Cost Driver Table

Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2006 Actuals)	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Opening Balance	$ 1,020,740	$ 1,125,164	$ 1,165,652	$ 1,267,201	$ 1,316,559	$ 1,325,685	$ 1,301,992	$ 1,604,971	$ 1,426,250
Staffing (Wages and Benefits)		$ 24,747	$ 46,579	$ 38,996	$ 49,108	$ 32,700	-$ 14,111	$ 27,769	$ 60,739
Materials and Equipment					$ 8,453		$ 30,549		
Smart Meter Decision Metering Exp							$ 187,044	-$ 187,044	
Distribution Lines and Feeders		$ 22,854		-$ 10,882				-$ 16,400	$ 42,000
Station Supplies and Expenses		$ 10,669			$ 14,139				$ 10,000
Billing and Collecting-Note 1	$ 77,024			$ 4,708		-$ 15,431	$ 40,097	-$ 21,688	$ 32,500
Meter Expenses	-$ 18,510	-$ 7,864							$ 7,000
Meter Reading Costs	-$ 5,516				-$ 10,640	-$ 22,919			
Energy Conservation/Community Relations	$ 57,362	-$ 22,290							$ 25,400
Office Expenses		-$ 8,034							
Contract Works + FFPC GIS Data Collection		$ 13,930							$ 19,500
Employee Training and Travel		$ 4,918	$ 32,962	$ 10,663	-$ 14,818	-$ 10,066	$ 15,864	-$ 3,700	
Outside Services-Consultant Fees				-$ 54,938			$ 26,265	-$ 32,503	
Employee Sick Leave Payout				$ 44,515	-$ 44,515				
Underground Operation and Maintenance									
Regulatory Expenses							$ 21,065	$ 19,600	$ 19,600
Painting/Outside Work-Summer Student			$ 21,041	$ 14,720					
Other	-$ 5,936	$ 1,558	$ 967	$ 1,576	$ 7,399	-$ 7,977	-$ 3,794	$ 35,245	$ 14,661
Closing Balance	$ 1,125,164	$ 1,165,652	$ 1,267,201	$ 1,316,559	$ 1,325,685	$ 1,301,992	$ 1,604,971	$ 1,426,250	$ 1,657,650

Following below are the line specific cost driver descriptions.

<u>Staffing (Wages and Benefits)</u>

The increase in 2008 represents half-year cost of the hiring of an apprentice lineman in May 2008.

The decrease in 2012 was due to an employee on Long-Term disability, resulting in a wage deduction.

The increase in wages in the 2014 Test Year represents the hiring of one FTE in June 2014, at a half-year estimated cost for wages, benefits and training of $51,000.

Year over year changes in compensation and benefits are detailed under "Employee Compensation and Benefits" in Exhibit 4, Tab 2, Schedule 4. This includes details of employee compliment, base wages, overtime and benefits by employee category.

Materials and Equipment

The increases in 2008 and 2012 are due to increase material purchases for small tools and truck repairs. In 2012, the decrease in Revenues from Non-Rate Regulated Utility Operations, created an increase of $15,338 truck expenses, due to the lower revenue off-set.

Smart Meter Decision

The Smart Meter rate decision, EB-2012-0327, directed the expense allocation of $187,044 of metering expenses in that year. OEB Board staff, when consulted, indicated that the decision effective late in the fiscal year created a 'lumpiness' in the expense/revenue distribution. The corresponding offset will occur in 2013.

Distribution Lines and Feeders

An expense increase of $22,854 in 2007 was due to increased 5135, Right of Way tree trimming.

The decrease in 2009 of -$10,882 was due to a decrease in 5135, Right of Way tree trimming.

The decrease in 2013 of -$16,400 is projected reduction in 5145, Maintenance of Underground Conduit. FFPC reallocated labour responses to the Town of Fort Frances Street Lighting retrofit in 2013.

In 2014, FFPC is proposing an increase of $42,000 attributable to:

- Incremental OM&A expenses projected at $25,681, which is 7% of $369,441 capital cost to complete FFPC's Long-Term Load Transfer (LTLT) capital project.

- The residual amount of $16,319 is for increased Miscellaneous Distribution Expenses, for the salary and benefits charged for the work performed by the Customer Service Technician to update and maintain FFPC system maps and records.

Station Supplies and Expenses

Increased station operations in 2007 resulted in a $10,669 increase.

In 2010, $14,139 was attributed to fees paid to Siemens for station maintenance.

In 2014, FFPC has projected the capital replacement of two transformer station breakers, estimated at a cost of $50,000. Incremental OM&A costs are estimated to be $5,000 for operating supplies and expenses. Maintenance costs are projected to increase by $5,000.

Billing and Collecting

The approved 2006 EDR rate application had allocated any costs for the collection of customer accounts, producing an increase in the 2006 Actual of $77,024.

An accounting error was made in 2012 that entered 2011 Billing and Collecting costs into 2012, creating at $15,431 decrease in expense for 2011. This would increase 2012 expenses by that amount.

Increased contracted services for postage and billing attributed to an increase of $24,666.

For 2014, FFPC is proposing $32,500 in extra costs for:

- $5,500 for wages/benefits for Customer Service Technician collection activities;
- Increase in $27,000 for higher contracted costs for contracted services, materials and postage paid to the Town of Fort Frances and Thunder Bay Hydro;

Metering Expenses

Declines in metering expenses in 2006 and 2007 were realized in anticipation for the Smart Meter Initiative, completed by FFPC in 2012.

For 2014, FFPC proposes an increase of $7,000 in metering expenses for costs for the Customer Service Technician to perform metering checks, updating records, maintaining inventory and like services.

Energy Conservation and Community Relations

In 2006 FFPC spent $57,362 on materials for energy conservation programs, prior to the OPA era.

In 2007, FFPC spent $30,635, which created a decrease of $22,290.

In 2014, $25,400 is for salary/benefits and training for the Customer Service Technician as below:

Potential New Postion Hire - Technical Customer Service Representative						
Reporting to:			President/CEO- non-union position			
Salary Range:			$55,000 - $70,000			
Hours of work			35 hours/week	1820	annually	
Salary + Benefits:		$ 80,000	Hourly:	43.956		
Annual Proposed Salary Hours					**Labour Includes:**	
HOURS	**%**					
				5085	**Miscellaneous Distribtion Expense**	
546	30%	**$ 24,000**	E-500-5085-1110	Salary	Joint pole maps and records. Distribution System voltage and load records	
			E-500-5085-1111	Benefits	(GIS subaccount below)	
				5086	**GIS Data**	
364	20%	**$ 16,000**	E-500-5086-1110	Salary	General records of physical characteristics of lines and substations,	
			E-500-5086-1111	Benefits	Joint pole maps and records. Preparing maps and prints. General clerical	
91	5%	**$ 4,000**		**5065**	**Meter Exp**	
			E-500-5065-1110	Salary	Clerical work on meter history, and associated equipment record cards,reports.	
			E-500-5065-1111	Benefits	Checking operation of demand meters, resetting time controls, etc.	
91	5%	**$ 4,000**		**5310**	**Meter Reading/Collecting**	
			E-530-5310-1110	Salary	Reading, resetting, managing keys, etc.	
			E-530-5310-1111	Benefits		
455	25%	**$ 20,000**		**5410**	**Community Relations-Sundry**	
			E-540-5410-1110	Salary	Employees directly engaged in providing services to the community	
			E-540-5410-1110	Benefits		
182	10%	**$ 8,000**		**5415**	**Energy Conservation**	
			E-540-5410-1110	Salary	Employees directly related to energy conservation.	
			E-540-5410-1110	Benefits		
54	3%	**$ 2,374**		**5420**	**Community Safety Program**	
			E-540-5410-1110	Salary	Employees directly engaged in providing services related to safety.	
			E-540-5410-1110	Benefits		
37	2%	**$ 1,626**		**4380**	**Expenses of Non-Rate Regulated Utility Operations**	
			E-480-438X-1110		4381-4383 **OPA Programs (sub accounts)**	
			E-480-438X-1110		Electricity Generation	
1820	**100%**	**$ 80,000**	**Total Hours / Percentage**			

The outcome of FFPC's 2013 Customer Satisfaction survey indicated that our customers would like enhanced consumer education offerings and the services of a Customer Service Technician would provide.

GIS Data Collection

FFPC partnered with the Town of Fort Frances to develop a comprehensive GIS asset management of all plant assets. The expense in 2007 was the starting point in this endeavor. The 2014 expense of $19,500 for wages, benefits and training is to record the work on FFPC's GIS mapping completed by the Technical Customer Service person.

Employee Training and Travel

FFPC generally hires new staff within the community and provides on the job training and outside skill development. The cost increases are attributable to:

In 2007, a new CEO and apprentice lineman were both hired.

In 2008, Board of Director and CEO travel continued with meeting and courses, generally in Toronto. An apprentice lineman was hired in May and the costs for two weeks of lineman training resulted in the $32,962 in costs. The cost of training for the Northern LDC is considerably hired than southern Ontario employees as each trip involved airplane and vehicular travel of approximately 8 hours each way, 16 hours for a return trip.

In 2009, CEO and lineman developmental training continued.

In 2010, a reduction in travel by the Board of Directors resulted in a reduction of $9,210 and the remainder of $5,608 was realized by a reduction in line staff training.

In 2011, there was a reduction of $4,008 in training as an apprentice lineman reached full journeyman status. The Board of Directors travel costs dropped by $3,992 and the remaining reduction of $2,066 was a decrease in CEO travel expenses.

In 2012, the hiring of an apprentice lineman increased training/travel costs by $8,888, CEO travel increased by $5,037 and the Board of Directors cost increased by $1,939.

In 2013, the budget was reduced by $3,700 to account for travel and training reductions for the CEO.

Outside Services (Audit, Legal and Consultant)

The reduction in 2009 was because of a reduction in the following contracted fees paid in 2008 for:

- Siemens – Station Work $27,782
- Loppacher Consulting- Engineering services $4,167
- Atikokan Hydro – herbicide spraying at station $2,000
- EnerSpectrum – distribution system analysis $20,989

FFPC collects in the 5630 account grouping accounting, legal and professional consultants. In 2012, FFPC paid for consultant services for completion of the 2012 IRM application. In 2013 FFPC paid $16,275 to BDO Dunwoody to complete a Scientific Research and Experimental Development (SR&ED) Tax Incentive Program, in which FFPC intends to recover $55,752 in tax credits. FFPC has ongoing litigation claim pending with a former employee of which all costs to date have been covered under FFPC's liability insurance. If a successful outcome of this pending litigation is reached, all costs would be covered by this insurance. An unsuccessful verdict would result in FFPC incurring costs for severance and litigation.

Retiree Benefits and Sick Leave Vested

FFPC does not offer the post-retirement life insurance, dental and health benefits to any present employees. In 2009, a vested sick leave payable of $44,515 was expensed to represent this outstanding liability to a long-serving employee. Minor increases are entered annually to adjust value.

Regulatory Expenses

The 2012 net cost driver of $21,065 as the allocation of the PILs decision of $31,882 in the 2012 IRM EB-2011-0146 into regulatory expenses. The expenses in 2013 and 2014 are for the COS rate application anticipated costs.

Summer Students

In 2008 and 2009 the costs of employing two summer students impacted costs by $12,041 and $14,720. The students performed painting and vegetation removal while performing community service on behalf of FFPC.

Bad Debt Write-Offs

As part of its Accumulated Provision for Uncollectable Accounts-Credit, Account 1130, FFPC writes off bad debts for uncollectable accounts in the preceding years. In addition, each year FFPC reviews the outstanding accounts for the current year and makes a determination on what, if any accounts may not be collectable in the following year. Therefore, Bad Debt Expense is a function of actual write offs and the above-noted adjustment to the Allowance for Doubtful Accounts. The Table 4.2.13, below, sets out the year end balances for Bad Debt Expense and the Accumulated Provision for Uncollectable Accounts-Credit in the years 2006 to 2012, along with the Bridge Year (2013) and Test Year (2014) forecasts.

Table 4.2.13: Bad Debt Expense and Allowance For Doubtful Accounts

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
	Billing and Collecting	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
5335	Bad Debt Expense	$ 6,763	$ 3,255	$ 4,951	$ 1,680	$ 10,996	$ 5,826	$ 10,976	$ 8,000	$ 8,000

FFPC expects a slight increase in bad debt expense due to the current economic situation in the Town of Fort Frances. In the first quarter of each year, FFPC credit customer accounts for a rebate payable on the undisbursed liability payable for the Historic Mill Agreement. This rebate payout reduces FFPC's bad debt expense.

Meter Reading Expenses – Prior to 2012

Prior to 2011, FFPC contracted to the Town of Fort Frances provide manual meter reading services on a monthly basis. The introduction of smart meter technology gave FFPC the ability to read meters electronically and consequently, the contract with the Town of Fort Frances was revised to provide month end meter readings for only the General >50 kW customers. The resulting cost savings in 2011 were $22,918 and in 2012 additional savings over and above the 2011 savings totaled $26,204.

Acct	Name	2006	2007	2008	2009	2010	2011	2012	2013 Bridge	2014 Test
5310	Meter Reading Expenses	$ 35,859	$ 33,508	$ 39,355	$ 42,332	$ 31,692	$ 8,774	$ 5,488	$ 6,000	$ 6,500

Meter Reading Expenses

Meter reading expenses in 2011 and 2012 were reduced by $22,918 and $26,204 respectively, as FFPC transitioned to electronic meter reading in 2010. In late 2011, FFPC began Time of Use billing and submitted our Prudence Review Application to the Ontario Energy Board under Board File #EB-2012-0327 in July 2012. On November 29, 2012, in its Decision and Order, the Board approved all capital and OM&A costs relating to the smart meter infrastructure. Total smart meter reading expenses have been estimated for 2013 Bridge and 2014 Test years below.

Projected Annual Meter Reading /MAS/ODS Costs	2010	2011	2012	2013 Bridge	2014 Test
Thunder Bay Hydro - MAS/ODS System Fee	$24,000	$24,000	$24,000	$24,000	$24,000
Kinetiq Canada - Fixed Fee	$5,973	$6,283	$6,324	$6,545	$6,800
Tbay Telephone - Monthly Phone Services	$4,796	$5,059	$5,175	$5,175	$5,200
Manual Meter Reading				$6,000	$6,000
	$34,769	$35,342	$35,499	$41,720	$42,000

All Other Expenses

Changes in all other expenses represent various year over year changes as described in the program by program variance analysis below and supported by Chapter 2, Appendix 2-JC, OM&A Program Table.

Variance Analysis by Program:

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22 2011, FFPC has provided variance analyses for the 2014 Test Year vs. 2006 Actual (last rebase year) and between the 2014 Test Year and 2012 Actual (Most Current Actual). As the last rebase year was eight years prior to the 2014 Test year, the variances may be greater due to the time lapse. FFPC has reviewed the variance of each program and provided explanations for variances exceeding a materiality threshold of $50,000. The variances are indicated in the following tables (Table 4.2.15 to Table 4.2.19) and an explanation of each variance is presented in the following section.

Table 4.2.15: Operations Expenses – Account Variances

2014 Test Year vs. 2012 Actual and 2014 Test Year vs. 2006 Board Approved

Programs	Last Rebasing Year (2006 Actuals)	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2006 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	
Operations				
Work Centre Building and Expenses	33,986	50,000		
Transformer Station Inspection	11,127	29,000	2,315	13,920
Overhead Plant Inspections	13,564	23,000	13,732	9,838
Underground Plant Inspections	4,065	15,000	-1,271	14,943
Misc Dist. Exp- GIS Contracted Works	13,931	43,000	31,724	38,000
Meter	46,115	35,000	6,303	-29,625
Transformer Inspections	5,674	2,000	1,184	-5,750
Reallocation of Salary from Admin		91,000	91,000	91,000
Misc Operations	26,469	83,000	11,712	51,594
Sub-Total	**154,931**	**371,000**	**156,699**	**183,920**

The Reallocation of the Lines Superintendent cost to the Operations from the Administration USoA # 5610 is has created a $91,000 variance as explained previously in the exhibit. The Miscellaneous Operations variance 2014 Test Year to 2006 Actual is a $52,000 due to the allocation of $16,319 for the Technical Customer Service person to update FFPC mapping and records.

Table 4.2.16: Maintenance Expenses – Account Variances

2014 Test Year vs. 2012 Actual and 2014 Test Year vs. 2006 Board Approved

Programs	Last Rebasing Year (2006 Actuals)	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2006 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	
Maintenance				
Transformer Station Maintenance	11,420	35,000	3,376	29,233
Vegetation Management- 5135	22,964	63,000	-3,563	49,794
Overhead Pole Maintenance	25,900	45,000	19,089	-7,403
Overhead Conductor	24,365	58,000	18,020	22,800
Underground Conductor Maintenance		24,000		
Maintenance of Meters-ODS Smart		26,000	-161,044	26,000
Reallocation of Salary from Admin		35,000		35,000
Misc Distribution	8,225	18,000	-8,097	17,925
Sub-Total	**92,874**	**304,000**	**-73,219**	**197,349**

The Reallocation of the Lines Superintendent cost to the Maintenance from the Administration USoA # 5610 is has created a $35,000 variance as explained previously in the exhibit. The one-time Smart Meter Maintenance cost in 2012 created a $161K variance. In 2012, FFPC expensed $187,044 for the entire USoA # 1556 balance for operations and maintenance as part of the 2012 Smart Meter Decision, EB-2012-0327. The $187,044 captured the operations and maintenance expenses for the entire Smart Meter project for the period 2009-2012. FFPC's vegetation management program expense created a variance of $49K due to the increased line staff involved in this maintenance program, beginning in 2008.

Table 4.2.17: Billing and Collecting Expenses – Account Variances

2014 Test Year vs. 2010 Actual and 2014 Test Year vs. 2006 Board Approved

Programs	Last Rebasing Year (2006 Actuals)	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2006 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	
Billing and Collecting				
Customer Billing	153,556	160,000	8,403	15,453
Collecting customer accounts	77,024	100,000	6,627	100,000
Bad Debt Expenses	6,763	8,000	-2,976	8,154
Sub-Total	237,343	268,000	12,054	123,607

The variance of $100,000 was due to missing allocation of Collection costs, USoA 5320 in the 2006 Board Approved rebasing year. It is believed that these costs may have been incorrectly allocated to USoA #5630, Outside Services Employed.

Table 4.2.18: Community Relations Expenses – Account Variances

2014 Test Year vs. 2012 Actual and 2014 Test Year vs. 2006 Board Approved

Programs	Last Rebasing Year (2006 Actuals)	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2006 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	
Community Relations				
Pole & Pad Mount Transformer Painting	5,237	4,750	-1,228	38
New Customer Tech Salary/Benefits		22,000	22,000	22,000
" - for Community Safety		2,400	2,400	2,400
" -Energy Conservation	57,362	8,000	8,000	8,000
Sub-Total	62,599	37,150	31,172	32,438

The variance in the Test Year 2014 of $42k in total is due to the planned new FTE hire of a Customer Service Tech person to fulfill the programs detailed.

Table 4.2.19: Administrative and General Expenses – Account Variances

2014 Test Year vs. 2012 Actual and 2014 Test Year vs. 2006 Board Approved

Programs	Last Rebasing Year (2006 Actuals)	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs. Last Rebasing Year (2006 Board-Approved)
Reporting Basis	CGAAP	CGAAP	CGAAP	
Administration and General				
Management & Non-Management Labou	307,402	321,500	-80,658	25,695
Corporate Leadership-Board	38,077	47,000	2,474	-2,872
Outside Services-Profession Consult.	66,399	73,000	-9,503	-63,713
Union Employee Benefits	64,266	90,000	9,058	37,725
Office Building Rent/Insurance	26,417	29,000	-139	29,000
Regulatory Expenses	10,383	44,750	-2,170	39,028
Miscellaneous	64,473	72,250	6,461	12,468
Sub-Total	577,417	677,500	-74,477	77,331

The negative variance in accounts USoA # 5605-5615 for the Management and Non-Management Labour pool is due to the reallocation of the Lines Superintendent costs into the O & M accounts. The negative variance in USoA #5630 of $63,713 was due to the incorrect allocation of Collection Costs, USoA #5320 into USoA#5630, Outside Services Employed during the 2006 EDR application process.

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

Compensation/Performance System

Union

FFPC's unionized staff is represented by the International Brotherhood of Electrical Workers (IBEW) Union. The current collective agreement expires April 30, 2014 and FFPC will be entering formal negotiations prior to that date. The current agreement, which was entered into May 01, 2011, includes annual wage increases of 3% over the next three years. FFPC recognizes that this increase may, on the surface be considered excessive given the current economic climate. However, FFPC would point out in order to achieve a balance between our neighbouring LDCs and industry averages, a 3% increase was negotiated. For example, FFPC's neighbouring LDC (Hydro One) wage rate for Journeyperson-Powerline Maintainer, effective March 29, 2012, was $38.75, while FFPC's Journeyman Lineman, effective May 1, 2012 was $36.19, resulting in a $2.56 per hour more than FFPC. An increase to match neighbouring LDC's Journeyman rate would have resulted in a 7% increase (based on negotiated 2012 wage rates,)

Management and Administration

The management and administration compensation plan consists of salaries and benefits. Each position within the company is reviewed by management and the Board of Directors as necessary, and may adjust based on the Union negotiated annual percentage increase. Each employee's position within their respective range is reviewed based on performance and an inflationary adjustment. Changes to senior management compensation, if any, are approved by the Board of Directors. FFPC has not offered any incentives or bonus compensation since its last cost of service application in 2006.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance and vacation. The plans are designed to address the health and welfare needs of the employee population, with similar plans for both union and management employees. FFPC does not provide post-retirement benefits to its employees. One existing employee has a legacy sick leave entitlement payout upon retirement that is expected to be disbursed at the end of the Test Year. There are not further entitlements to sick leave payout for any other present or future staff.

All full time staff participates in the OMERS pension plan.

Employee Compensation and Benefits:

The employee complement, compensation and benefit information is provided in table below. FFPC has aggregated the management and administration together in the management category, as there are fewer than three employees in this category. This aggregation will be continued to ensure no category contains three or fewer employees.

Our union line staff earn overtime hours for emergency trouble calls and for 'stand-by' time. 'Stand-by' time compensations a journeyman lineman one (1) day off for each week of emergency stand-by, where this employee is on 24 hour duty to answer FFPC's dedicated emergency cell phone and to be available for emergency trouble calls.

Our line crew may 'bank' overtime earned and to take 'time-off-in-lieu' for overtime hours banked. The majority of all earned overtime or 'bank' time is taken as 'time-off-in-lieu', greatly reducing overtime hours paid.

Staffing and Compensation Levels

FFPC participates in market surveys in order to pay competitive salaries to its management staff to attract and retain talented employees. FFPC recognizes the cost of managing its human resource assets and the time and resources involved in training new staff. Consequently, FFPC needs to retain staff at market rates. FFPC continues to monitor and review its salary structure with its Board of Directors on a yearly basis. All management positions are reviewed and adjustments are made by the Board of Directors when deemed appropriate.

FFPC is undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. All management positions play an important role in the design and implementation of these replacements/enhancements. Regulatory, financial reporting and technical operations requirements have changed the way FFPC does business. The existing Management and Administration staff have assumed multiple job roles to meet these needs. FFPC has utilized consultants to fill gaps not covered by internal staff. Within the scope of this rate application, both the Lines Superintendent and the Finance and Regulatory Officer will require replacement within the next four years and succession planning has been ongoing.

FFPC's line staff is well positioned for the future with an experienced staff of four Red Seal certified journeyman linemen and one first year apprentice, who is a qualified Red Seal Electrician. FFPC has utilized summer students to maintain property and update GIS records.

Ontario Energy Board Chapter 2 Filing Requirements which states "Where there are three, or fewer, full-time equivalents (FTEs) in any category, the Applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs". FFPC has aggregated the management and administration together in the management category.

The salaries and wage amounts include only salaries and wages paid for worked time and are exclusive of salaries and wages paid for vacations, stat holidays, floater days, sick leave, bereavement leave and other miscellaneous paid leave which are considered benefits.

The benefit amounts include FFPC's costs to provide, as mentioned above, all paid leave time not worked, extended health care, dental, long-term disability and life insurance, along with OMERS for all employees.

Staffing Level at Last Cost of Service Application – 2006

FFPC maintained staffing levels from 2006 until 2008 with the following positions:

- President and CEO- Management
- Lines Superintendent – Management
- Finance and Regulatory Office – Non-Union
- Administrative Assistant – Non-Union
- Four Journeyman Lineman- Union

The following table provides a summary of FFPC's Staffing and Compensation table from the 2006 rebasing year. 2006-2012 Actuals and including the 2013 Bridge and 2014 Test Year.

Differences between the Staffing and Compensation table and OM&A drivers row- Staffing (Wages and Benefits) are due to the grouping of wages and salaries within the cost driver table to other drivers such as 'Summer Student' (wages) and 'Employee Sick Leave Payout' (benefit) within the table. The 'Contributing Factors' refer to the main cost drivers only and do not attempt to reconcile to the 'Total Change' in wages and benefits.

Appendix 2-K
Employee Costs

1	Last Rebasing Year - 2006-Board Approved	Last Rebasing Year - 2006-Actual	2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Number of Employees (FTEs including Part-Time)[1]										
Management (including executive)	4	4	4	4	4	4	4	4	4	5
Non-Management (union and non-union)	4.0	4.0	4.0	5.3	5.7	5.3	5.3	5.3	5.3	5.3
Total	8.0	8.0	8.0	9.3	9.7	9.3	9.3	9.3	9.3	10.1
Total Salary and Wages including ovetime and incentive pay										
Management (including executive)	$ 217,190	$ 197,775	$ 228,308	$ 243,093	$ 253,003	$ 249,819	$ 268,435	$ 263,128	$ 275,000	$ 340,362
Non-Management (union and non-union)	$ 171,226	$ 208,845	$ 206,797	$ 257,231	$ 290,217	$ 296,340	$ 288,794	$ 319,773	$ 330,745	$ 345,014
Total	$ 388,416	$ 406,620	$ 435,105	$ 500,324	$ 543,220	$ 546,159	$ 557,229	$ 582,901	$ 605,745	$ 685,376
Change Amount- Current year vs Prior Year		**$ 18,204**	**$ 28,485**	**$ 65,219**	**$ 42,896**	**$ 2,939**	**$ 11,070**	**$ 25,672**	**$ 22,844**	**$ 79,631**
Total Benefits (Current + Accrued)										
Management (including executive)	$ 78,615	$ 109,627	$ 114,162	$ 99,866	$ 155,046	$ 119,850	$ 125,620	$ 139,030	$ 136,500	$ 161,358
Non-Management (union and non-union)	$ 52,275	$ 49,502	$ 48,502	$ 57,703	$ 64,565	$ 72,491	$ 72,118	$ 78,279	$ 83,000	$ 90,000
Total	$ 130,890	$ 159,129	$ 162,664	$ 157,569	$ 219,611	$ 192,341	$ 197,738	$ 217,309	$ 219,500	$ 251,358
Change Amount- Current year vs Prior Year		**$ 28,239**	**$ 3,535**	**-$ 5,095**	**$ 62,042**	**-$ 27,270**	**$ 5,397**	**$ 19,571**	**$ 2,191**	**$ 31,858**
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)	$ 295,805	$ 307,402	$ 342,470	$ 342,959	$ 408,049	$ 369,669	$ 394,055	$ 402,158	$ 411,500	$ 501,720
Non-Management (union and non-union)	$ 223,501	$ 258,347	$ 255,299	$ 314,934	$ 354,782	$ 368,831	$ 360,912	$ 398,052	$ 413,745	$ 435,014
Total	$ 519,306	$ 565,749	$ 597,769	$ 657,893	$ 762,831	$ 738,500	$ 754,967	$ 800,210	$ 825,245	$ 936,734
Change Amount- Current year vs Prior Year		**$ 46,443**	**$ 32,020**	**$ 60,124**	**$ 104,938**	**-$ 24,331**	**$ 16,467**	**$ 45,243**	**$ 25,035**	**$ 111,489**

2

3 The following analysis describe the prior year to current year variances in the summary totals for
4 'Wages' and 'Benefits'. 'Wages' include all salaries, wages and overtime for all employees, permanent
5 and part-time of FFPC. 'Benefits' include the following:

6 - Employer contributions for source deductions that adhere to the Government of Ontario source
7 deductions;
8 - Employee personal time off for vacation, statutory holidays, sick time and personal leave as per
9 individual employment contract;
10 - Employer paid benefit health coverage for hospitalization, vision and dental care;
11 - Disability coverage for eligible employees;
12 - Legacy vested sick leave benefit for one employee.

13
14 The year to year analysis has used the outcomes-based approach to highlight the main cost drivers
15 rather than to report on individual routine cost variances. Minor variances between the year-to-year
16 comparison table and the cost drivers explanations are due to typical differences due to source
17 deduction costs and employee overtime and time off changes.

2006 Actual to 2007 Actual

2006 to 2007	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.0	$ 30,533	$ 4,535	$ 35,068
Union	0.0	$ (2,048)	$ (1,000)	$ (3,048)
Total	0.0	$ 28,485	$ 3,535	$ 32,020

Total: Change in FTE: 0 Change in Wages and Benefits: + $ 32,020

Contributing Factors – Management

FFPC staff changes included the new hiring of the President/CEO. A long serviced Lines Supervisor retired and was replaced by a senior lineman within the corporation, creating an offsetting overlap of three months. The Administrative Assistant retired and was replaced from with a one month overlap. Change in wages: $ +27,103

Higher OMERS contributions due to staff overlap. Change in benefits: $ +4,212

Contributing Factors - Union

An apprentice lineman was hired in January 2007 to replace the promotion of one lineman to Lines Supervisor, effective July 2007, with a six month overlap:

Change in wages: $ -5,773

Union negotiated increase of 2.5% was effective May 1, 2007. Change in wages: $ +4,191

Changes in vacation time payable with staffing changes in 2007 resulted in a:

Change in Benefits: -$ 1,468

2007 Actual to 2008 Actual

2007 to 2008	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.0	$ 14,785	$ (14,296)	$ 489
Union	1.3	$ 50,433	$ 9,201	$ 59,634
Total	1.3	$ 65,218	$ (5,095)	$ 60,123

TOTAL Change in FTE: +1.3 Change in Wages and Benefits: +$64,123.

Contributing Factors – Management

Salary reviews were completed for non-union positions to align with industry wage guidelines.

Change in wages: +$13,715.

The decreased benefits were due to reduced vacation time payable for new staff hires.

Change in benefits: - $12,879.

Contributing Factors - Union

Union negotiated increase of 3.0% was effective May 1, 2007. Change in wages: + $2,995.

A new line apprentice was hired in May 2008. Change in wages: +$26,471.

Step progression for the second year lineman . Change in wages: + $6,339.

Two summer students were hired to perform community service. Change in wages: +$12,781.

Increase in benefits due to additional lineman. Change in benefits:+$9,201.

2008 Actual to 2009 Actual

2008 to 2009	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.0	$ 9,910	$ 55,180	$ 65,090
Union	0.3	$ 32,986	$ 6,863	$ 39,849
Total	0.3	$ 42,896	$ 62,043	$ 104,939

TOTAL Change in FTE: + 0.3 Change in Wages and Benefits: + $104,939.

Contributing Factors – Management

Salary increases of 3% were adopted from the union increase. Change in wages: +$7,139

The superintendent was granted a sick leave payout payable at retirement:

Change in benefits: + $44,515.

Increase in vacation entitlement, sick leave and disability benefit cost for non-union staff.

Change in benefits: + $8,172

Contributing Factors - Union

Change in FTE: +0.3

This was the first full year of the additional apprentice lineman. Change in Wages: + $13,226

Union negotiated increase of 3.0% was effective May 1, 2009. Change in wages: + $5,764.

Step progression for two apprentice lineman: Change in wages: +$ 10,745.

Overtime wages paid: Change in wages: +$ 1,628

2009 Actual to 2010 Actual

2009 to 2010	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.0	$ (3,184)	$ (35,196)	$ (38,380)
Union	-0.3	$ 6,123	$ 7,926	$ 14,048
Total	-0.3	$ 2,939	$ (27,270)	$ (24,332)

TOTAL Change in FTE: -0.3 Change in Wages and Benefits: -$24,332.

Contributing Factors – Management

Year end wages accrual adjustment. Change in wages: - $2,920

The sick leave payout granted in 2009 versus 2010: Change in benefits: - $44,515.

Increase in vacation benefit for non-union staff: Change in benefits: +$ 7,191

Contributing Factors - Union

Change in FTE: -0.3

FFPC reduced summer student staff by one person. Change in FTE: -0.3
Change in wages: -$9,253.

Union negotiated increase of 3.0% was effective May 1, 2010. Change in wages: + $5,726.

FFPC linemen received progressions for 2nd year to 3rd year adjustment (part year) and 3rd year to 4th year (full year.) Change in wages: +$ 11,403.

Increase in leave benefits paid in 2010: Change in benefits: +$7,048.

2010 Actual to 2011 Actual

2010 to 2011	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.0	$ 18,616	$ 5,770	$ 24,386
Union	0.0	$ (7,545)	$ (373)	$ (7,918)
Total	0.0	$ 11,071	$ 5,397	$ 16,468

TOTAL Change in FTE: 0 Change in Wages and Benefits: +$16,468

Contributing Factors – Management

FFPC staffing levels remained static. All staff received an increase of 4.0%.
Change in wages: +$ 13,221

A salary review on the Cost and Regulatory Analyst position was upgraded to Finance and Regulatory Officer, effective July 2011. Change in Wages: + $ 4,620.

Employees within group had extended sick leave: Change in Benefits: + $5,047.

Contributing Factors - Union

Union staff negotiated an increase of 4% effective May 1, 2011.
Change in wages: +$ 8,882.

Two linemen received progression wage adjustments: Change in wages: + $11,798.

One lineman was on extended sick leave due to injury from May 2011 until Long Term Disability benefits began in September 2011:
Change in wages: - $30,423.
Change in benefits: + $ 9,524.

FFPC did not pay wages for employee while on LTD Benefits from September-February 2012.

Overtime wages paid. Change in wages: + $ 1,547

2011 Actual to 2012 Actual

2011 to 2012	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.1	$ (5,307)	$ 13,410	$ 8,103
Union	0.0	$ 30,979	$ 6,161	$ 37,140
Total	0.1	$ 25,672	$ 19,571	$ 45,243

TOTAL Change in FTE: +.1 Change in Wages and Benefits: + $45,243

Contributing Factors – Management

The change in FTE was due to a one month overlap while a non-union employee went one sick leave and continued to work part-time until a replacement was hired to fill this position.

Change in Wages: -$4,753 Changes in Benefits: +$4,753

Increased vacation entitlement and payout resulted in: Changes in Benefits: +$8,678

Contributing Factors - Union

Union staff negotiated an increase of 3% effective May 1, 2012. Change in Wages: +$ 7,344

Progression Increases for one lineman to journeyman status: Change in Wages: +$ 5,072.

The return in March 2012 from Long Term Disability of a lineman caused an increase in wages calculated as the difference between the 2011 reduction in wages of (-$30,423) versus 2012 reduction in wages (-$12,169): Change in Wages: +$18,254

A retirement gratuity of $5,000 was paid as per the union collective agreement: Change in Benefits: +$5,000.

2012 Actual to 2013 Bridge

2012 to 2013 Bridge	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.0	$ 11,872	$ (2,530)	$ 9,342
Union	0.0	$ 10,972	$ 4,721	$ 15,693
Total	0.0	$ 22,844	$ 2,191	$ 25,035

TOTAL Change in FTE: 0.0 Change in Wages and Benefits: +$25,035

Contributing Factors – Management

In 2013 all staff received a wage adjustment of 3.0%. Change in Wages: +$ 9,536

In preparation of this COS application, the Finance and Regulatory Officer was compensated for overtime hours worked and not taken off in lieu: Change in Wages: +$ 9,870

New staff was compensated at a lower rate than previous staff:
Change in wages - $ 8,366.
Change in benefits: - $ 2,530.

Contributing Factors - Union

Union staff negotiated an increase of 3% effective May 1, 2013. Change in wages: +$ 7,122.

Progression Increases for one apprentice to second year rate: Change in wages: +$ 5,643.

Reduced overtime paid versus prior year: Change in wages: - $ 1,808

Increased costs for vacation entitlement and standard employee benefits:
Change in Benefits: +$4,721.

2013 Bridge to 2014 Test

2013 to 2014 Test	Change in FTE	Change in Wages	Change in Benefits	Changes in Wages & Benefits
Management	0.8	$ 65,362	$ 24,858	$ 90,220
Union	0.0	$ 14,269	$ 7,000	$ 21,269
Total	0.8	$ 79,631	$ 31,858	$ 111,489

TOTAL Change in FTE: 0.8 Change in Wages and Benefits: +$111,489

Contributing Factors – Management

Retirement for FFPC's Line Superintendent is scheduled for the fall of 2014 and a three month overlap for training would be necessary in that period. The superintendent plans to take his vacation entitlement at the completion of the overlap training period, which would account for seven additional weeks of benefit coverage.

Change in FTE: +.3 Change in Wages: +$19,862 Change in Benefits: +$11,858

Incremental salary adjustments for all staff during annual review:

Change in Wages: + $8,500

FFPC intends to create the new position of a Technical Customer Service Representative in June 2014 to:

- Continue Green Energy Initiatives duties temporarily assumed by management staff;
- Relocate customer service duties such as metering, collection and meter reading duties from current contracted and line staff. This reallocation will allow line staff to focus on existing maintenance and upcoming major capital replacements;
- Create a dedicated customer contact person for initiatives such as generation, energy management, safety and education to ensure customer continuity;
- Assist in the advancement and development of FFPC's Customer Information System (CIS) interface with GIS mapping and FFPC's Asset Management Policy ;
- Restore FFPC's participation in local events such as trade shows, community safety and educational events.

FFPC requires a dedicated employee to provide a vital link between the technical activities arising from industry initiatives and our customer needs. Current staff is unable to complete these customer initiatives in addition to their current job duties and have been working overtime hours to cover this vacancy.

FFPC conducted a Customer survey in 2013 and as per customer feedback, FFPC will be launching consumer education campaigns beginning in 2014 that focus on the consumer topics of interest as listed below:

% Responses	Most Popular Topics of Interest
14.7%	Conservation
13.2%	Renewable Generation
12.7%	Smart Meters
11.1%	Smart Grid
9.8%	Understanding You Bill
8.7%	Demand Management
0.3%	Time-of-Use Rates
0.5%	Other

(From FFPC's 2013 Customer Satisfaction Survey Results.)

The cost for the Technical Customer Service Representative is forecasted to be:

Change in FTE: +.5 (Test Year) Change in Wages: + $37,000- Test Year
Change in Benefits: +$13,000- Test Year

Contributing Factors - Union

The vacancy of the Lines Superintendent may filled by an existing member of the line staff and, if this occurs, the need for a replacement journeyman lineman would be necessary. As FFPC is

beginning the first phase of its major capital plant replacement, and according to FFPC's Asset Management Policy, the need to restore FFPC's lineman staff compliment to five is necessary to complete the capital work required.

If FFPC hires an existing journey lineman from outside the corporation, there will be only minor incremental costs for wages and benefits. In the past, FFPC has had difficulty in retaining lineman who are hired by FFPC from other LDCs, such as Hydro One.

If the replacement is an apprentice lineman, the lower wages/benefits paid to the apprentice would be partially offset by the cost of training and support.

Change in Wages: -$2,000 (With the anticipated apprentice lineman scenario)

The present Union contract expires April 30, 2014, although FFPC anticipates a standard incremental wage adjustment within the 2.5-3.0% range.

Change in Wages: +$7,269 Change in Benefits: +$7,000

Progression increases for apprentice linemen: Change in Wages: +$8,769

FFPC does not have an actuary report as it does not offer post-retirement benefits to its employees. As mentioned prior, there is an outstanding sick time benefit payout, in which upon retirement or death, the employee will be paid for 274.5 days of accumulated sick leave at current wage rate. The amount of $44,515 (as noted in the 2009 Actual vs 2010 Actual review) was allocated in 2009 for this pending payable and adjusted to 2012 wage structure an additional $3,169 in 2012. There will be no further sick time benefits paid out as per the contract revision for non-union staff in 2009.

CHARGES TO AFFILIATES FOR SERVICES PROVIDED:

Introduction:

FFPC performs and receives services from its shareholder, the Municipality of the Town of Fort Frances (TOFF). FFPC performs rework and street light maintenance at the same rates as is charged to other Jobbing customers. The Shareholder does not receive special rates and the fully allocated costs along with slight profits are realized from work performed on behalf of the Shareholder. The charges for services provided are comprised of employee time at fully burdened rates, as well as truck and material expenses at fully burdened costs. FFPC expects a marked reduction in recoverable work performed for the shareholder as the Town of Fort Frances will complete in early 2014 a complete retrofit LED replacement of all existing street lights.

The Shareholder, in turn, charges to FFPC, when necessary, full and typical rates for services for employee time and benefits and machinery.

FFPC's business office is located on the lower level of the Town Civic Centre and FFPC is charged monthly for a share of associated operating costs, such as utilities, cleaning services, etc. This shared location is convenient for residents, FFPC customers and all staff.

The Town of Fort Frances provides contracted services for meter reading, billing, collecting and accounting services required by FFPC to serve its customers. This contract compensates for services provided in a cost efficient manner for the customers of FFPC by utilizing existing staff, office space and infrastructure effectively.

FFPC pays for the following services:

- Meter Reading – This contract has been reduced to a monthly reading of FFPC's large General Customers to allow for meter resets not available currently through our Smart Meter capabilities. Spot meter reads to investigate meter trouble may also occur. FFPC pays the wages and benefits on an hourly basis. This contract may be eliminated as noted in the 2014 Test year FFPC staffing addition.
- Customer Billing – FFPC pays for the services of a billing clerk, utility clerk, cashier and receptionist for counter and phone services. The billing clerk schedules, bills, prints and mails customer bills. The utility clerk completes customer account changes, the collection of accounts and refunds to customers. The cashier/receptionist collects payments and field customer inquiries.
- Accounting Services – Preparation of billing and unbilled revenue accounting, payroll and source remittances, accounts receivable, payable, banking and financial reporting. Other services provided include IT and telephone support.

The table below provides a summary of charges paid to the Town of Fort Frances, under contract for services provided for each year.

Table: Shared Contracted Services Expenditures to Shareholder- Town of Fort Frances

Year 2006-2009 *(continued)*

Name of Company				**Annual Price for Service**			
From	**To**		**Pricing Methodology**	**2006**	**2007**	**2008**	**2009**
Town of Fort Frances	**FFPC**	***Meter Reading- 5310***	***Wages/Benefits***	$ 35,859	$ 33,508	$ 39,355	$ 42,332
Town of Fort Frances	**FFPC**	***Customer Billing-5315***	***Contract***	$ 38,515	$ 40,271	$ 40,416	$ 42,944
Town of Fort Frances	**FFPC**	***Collecting-5320***	***Contract***	$ 71,718	$ 73,779	$ 78,710	$ 84,051
Town of Fort Frances	**FFPC**	***Accounting Services***	***Contract***	$ 24,000	$ 24,000	$ 25,200	$ 25,767
Town of Fort Frances	**FFPC**	***GIS Services***	***Wages/Benefits***	$ 17,206	$ 13,931	$ 11,860	$ 13,014
Town of Fort Frances	**FFPC**	***Office Space Cost-5670***	***Costs/space used***	$ 13,284	$ 13,284	$ 13,284	$ 13,284
		Total		**$ 200,583**	**$ 198,772**	**$ 208,826**	**$ 221,391**
			Percentage Change versus prior		**-0.91%**	**4.81%**	**5.68%**

Table: Shared Contracted Services Expenditures to Shareholder- Town of Fort Frances

Year 2010-2014 *(continued)*

Name of Company				Annual Price for Service			Bridge	Test
From	To		Pricing Methodology	2010	2011*	2012	2013	2014
Town of Fort Frances	FFPC	*Meter Reading- 5310*	*Wages/Benefits*	$ 29,616	$ 8,774	$ 5,488	$ 6,000	$ -
Town of Fort Frances	FFPC	*Customer Billing-5315*	*Contract*	$ 43,881	$ 38,583	$ 47,619	$ 65,000	$ 65,000
Town of Fort Frances	FFPC	*Collecting-5320*	*Contract*	$ 86,499	$ 76,807	$ 91,960	$ 72,000	$ 75,000
Town of Fort Frances	FFPC	*Accounting Services*	*Contract*	$ 26,475	$ 24,508	$ 29,498	$ 28,000	$ 29,000
Town of Fort Frances	FFPC	*GIS Services*	*Wages/Benefits*	$ 9,675	$ 10,744	$ 11,276	$ 12,000	$ 12,000
Town of Fort Frances	FFPC	*Office Space Cost-5670*	*Costs/space used*	$ 13,284	$ 13,284	$ 13,284	$ 13,284	$ 13,284
		Total		**$ 209,430**	**$ 172,700**	**$ 199,125**	**$ 196,284**	**$194,284**
			Percentage Change	**-5.71%**	**-21.27%**	**13.27%**	**-1.45%**	**-1.03%**

Error was made that booked all of the December 2011 contracted expenses in 2012, inflating 2012 expenses.

FFPC does not have any active affiliate organizations or any shared corporate costs to allocate.

PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES:

FFPC purchases many services and products from third parties.

A review of all expenditures by vendor, where the annual amount exceeded $50,000 per year, is listed in the following table for the years 2006-2012, below. This table contains the historical Non-Affiliate Supplier information including Vendor, total amount of goods or services purchased and the procurement method used.

FFPC purchases equipment, materials and services in a cost effective manner with full consideration given to the price as well as product quality, compliance, delivery timelines, and quality of services. Vendors are reviewed to gauge product knowledge, reputation and the ability to meet FFPC's product needs. FFPC continues to operate with an economical mindset to acquire value based products and services.

A copy of FFPC's purchasing policy has been provided in Appendix A. FFPC has followed this policy in the past and will continue to do so.

The table below provides a history of all Non-Affiliated Suppliers from 2006-2012.

2006 Non-Affiliated Vendor Suppliers			
Vendor Name	Total Invoice Paid	Product or Service	Procurement Method
Sunset Country Ford	$ 76,934	2007 Ford F450 Dump Truck -$63156, Other Services -$13778	Tender
Thunder Bay Hydro	$ 132,904	CIS Services,Wholesale Settlement, Remote Meter Readings	Contract
2007 Non-Affiliated Vendor Suppliers			
Vendor Name	Total Invoice Paid	Product or Service	Procurement Method
Carte International Inc.	$ 57,182	Customer and replacement capital transformer purchases.	Purchase Order
Thunder Bay Hydro	$ 109,999	CIS Services, Smart Meter Readings, OPA Program Support	Contract
2008 Non-Affiliated Vendor Suppliers			
Vendor Name	Total Invoice Paid	Product or Service	Procurement Method
Thunder Bay Hydro	$ 110,961	CIS Services, Smart Meter Readings, OPA Program Support	Contract
2009 Non-Affiliated Vendor Suppliers			
Vendor Name	Total Invoice Paid	Product or Service	Procurement Method
Carte International Inc.	$ 75,002	Customer capital transformer purchases.	Purchase Order
Elster Canadian Meter	$ 520,821	Smart Meter and Collector Purchases	RFP
Thunder Bay Hydro	$ 187,218	CIS Services, Smart Meter Readings/CapitalPurchases -$17291	Contract
		Meter Service Provider, $10080, OPA Program Support, $55385.	
2010 Non-Affiliated Vendor Suppliers			
Vendor Name	Total Invoice Paid	Product or Service	Procurement Method
Elster Canadian Meter	$ 126,939	Smart Meter Purchases	RFP
Mark Caron Electric Ltd.	$ 60,996	OPA Conservation Initiatives- payment for work completed	OPA Contract
Thunder Bay Hydro	$ 92,845	CIS Services, Smart Meter Readings, OPA Program Support	Contract
Tompkins Hardware	$ 65,366	Generator -Leasehold Improvement	Purchase Order
Wajax Industries Limited	$ 277,867	Digger Derrick Truck	Tender
2011 Non-Affiliated Vendor Suppliers			
Vendor Name	Total Invoice Paid	Product or Service	Procurement Method
BDO Dunwoody	$ 50,082	Accounting services and IFRS conversion.	Contract
Thunder Bay Hydro	$ 167,116	CIS Services, Smart Meter Readings, $118,462	Contract
		Meter Service Provider, $10848, OPA Program Support, $37,806.	
2012 Non-Affiliated Vendor Suppliers			
Vendor Name	Total Invoice Paid	Product or Service	Procurement Method
Mark Caron Electric Ltd.	$ 59,952	OPA Conservation Initiatives- payment for work completed	OPA Contract
Thunder Bay Hydro	$ 146,701	CIS Services, Smart Meter Readings, $106,314	Contract
		Meter Service Provider, $10848, OPA Program Support, $29,539.	

TEST YEAR INCLUSION OF LEGACY PROGRAMS

FFPC has not included any legacy program costs in the 2014 Test Year revenue requirement.

DEPRECIATION, AMORTIZATION AND DEPLETION:

FFPC's amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year plus 100% of the current year capital additions.

FFPC, through its contracted services to the Town of Fort Frances, calculated depreciation on the whole year and did not use the Board Policy of the "half-year" rule. FFPC realizes this deviates from standard practice and will implement this methodology for in 2014. FFPC is of the understanding that our current rates were approved in 2006 which assumed full year depreciation on new capital at the time. The materiality of this departure is low as FFPC's annual work within this rate period was concentrated on maintenance of capital assets that are nearing 'end-of-life' status. FFPC's capital spending, with the exception of the purchase of fleet vehicles, has been on average annual cost of $186,000. The difference in methodology resulted in an estimated variance of less than $8,000 per year, based on a "half-year" amount at an 8% depreciation rate.

FFPC had legacy capital asset valuation irregularities that undervalued certain capital assets and the depreciation and amortization calculated on these capital assets. FFPC actions include:

- FFPC had recorded its Municipal Transformer Station as a Distribution Station, USoA Account 1820. The assets were transferred to the USoA# 1815 during the 2012 fiscal year.

- FFPC had pooled capital assets in Poles, Towers and Fixtures, (USoA #1830) and understated the capital assets recorded in Overhead Conductors and Devices (USoA #1835), Underground Conduit (USoA 1840), and Underground Conductors and Devices (USoA 1845).

- FFPC contracted BDO Canada LLP, Advisory Services to perform a cost allocation on FFPC's current capital assets valuation. This reassessment normalized FFPC's individual capital asset amounts to industry standards based on GIS physical plant quantities and characteristics. FFPC is adjusting individual capital assets of the USoA 1830-1840 as shown

in the table below in 2013. FFPC would like to note that the total asset evaluation is not change as the total net book value for USoA 1830-1840 remained constant at $1,658,514.

BDO Canada LLP. Cost Allocation Summary for Fort Frances Power Corporation, as at December 31, 2012							
		Original (prior to allocation)			Revised (following cost allocation)		
Account	Asset Type	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
1830	Poles, Towers, Fixtures	$ 5,169,630	$ 3,985,630	$ 1,184,000	$ 3,308,296	$ 2,128,537	$ 1,179,759
1835	OH Conductor	$ 401,309	$ 750	$ 400,558	$ 1,622,789	$ 1,360,441	$ 262,348
1845	UG Conductor	$ 97,937	$ -	$ 97,937	$ 427,295	$ 302,332	$ 124,963
1840	Underground Conduit	$ 2,183	$ 26,163	$ (23,980)	$ 312,678	$ 221,235	$ 91,443
		$ 5,671,059	**$ 4,012,543**	**$ 1,658,515**	**$ 5,671,058**	**$ 4,012,544**	**$ 1,658,514**
				Completed by Ziad Akkaovi, Advisory Services, BDO Canada LLP.			
Note 1 - as assets are 71% depreciated, it is assumed that the allocation will utilize the same accumulated depreciation.							

- FFPC has, over the last five years, determined the condition based physical plant characteristics during the conversion to GIS based mapping of all capital plant. FFPC shared GIS services with the Town of Fort Frances to minimize cost and overlap.

- FFPC completed an extensive Asset Management Policy and determined FFPC's 'Adopted Useful Life' of all assets and the corresponding 'Remaining Useful Life Relative to FFPC Adopted Useful Life'. The 'FFPC Summary of Assets Owned' is included in Appendix C to this exhibit. These 'Adopted Useful Life' values have been used in the Appendix 2-CF to Appendix 2-CI, mentioned below.

- FFPC has moved our capitalization policy to be consistent with CGAAP and has applied deprecation rates consistent with the Kinectric's study but adjusted, when necessary, to reflect FFPC's Asset Management Policy. FFPC has completed the required Appendix 2-CF to Appendix 2-CI, inclusive to detail FFPC's cost capitalization policy.

- Table 4.2.28 below provides a summary of amortization expense for the years 2006 to 2012 Actual, 2013 Bridge Year (CGAAP) and 2014 Test Year (CGAAP).

- FFPC, at this time, has not identified any Asset Retirement Obligations (AROs) regarding their assets. A copy of FFPC's Position Paper on AROs has been included as Appendix review of these obligations will be undertaken as part of FFPC's Asset Management Policy.

Table 4.2.28: – Summary of Amortization Expense for 2006 to 2014 – CGAAP

Summary of Amortization Expenses - 2006 - 2014 CGAAP										2012	2012	2013 Bridge	2014 Test
CCA Class	OEB USoA	*Description*	2006	2007	2008	2009	2010	2011		(CGAAP)	(CGAAP)	(CGAAP)	(CGAAP)
12	1611	**Computer Software**									$ 2,202	$ 1,593	$ 4,743
n/a	1805	**Land**											
1	1808	**Building & Fixtures**	$ 8,559	$ 9,234	$ 9,234	$ 13,621	$ 14,198	$ 14,497		$ 14,633	$ 11,067	$ 11,131	$ 11,127
47	1815	**Transformer Station >50kV***									$ 9,370	$ 9,386	$ 9,553
47	1820	**8th St Station**	$ 25,875	$ 25,756	$ 26,009	$ 26,025	$ 26,133	$ 26,133		$ 26,133			
47	1830	**Distribution Lines**	$ 205,237	$ 209,720	$ 191,193	$ 176,098	$ 182,303	$ 187,275		$ 176,581	$ 54,609	$ 41,686	$ 31,206
47	1835	**Overhead Conductor**						$ -			$ 10,402	$ 10,523	$ 11,074
47	1840	**Underground Conduit**	$ 1,814	$ 2,181	$ 2,711	$ 2,972	$ 3,424	$ 3,685		$ 4,005	$ 1,827	$ 1,827	$ 1,996
47	1845	**U/G Conductor & Devices**									$ 10,151	$ 10,361	$ 10,702
47	1850	**Transformers**	$ 43,009	$ 44,897	$ 45,583	$ 46,826	$ 45,150	$ 37,856		$ 30,987	$ 16,032	$ 10,989	$ 12,855
47	1855	**Services**										$ 25	$ 100
47	1860	**Meters**	$ 13,755	$ 14,023	$ 14,075	$ 14,126	$ 2,844	$ -		$ 38,356			
47	1860	**Meters (Smart Meters)**								$ 209,763	$ 51,564	$ 51,564	$ 51,755
47	1908	**Building & Fixtures**	$ 727	$ 727	$ 727	$ 727	$ 218	$ 206		$ 74	$ 6,680	$ 6,961	$ 7,215
13	1910	**Leasehold Improvements**	$ 2,101	$ 2,101	$ 2,101	$ 887	$ 2,545	$ 2,545		$ 2,545	$ 2,427	$ 2,452	$ 2,477
8	1915	**Office Furn & Equip**	$ 3,274	$ 3,240	$ 4,533	$ 4,652	$ 4,092	$ 3,792		$ 3,680	$ 8,654	$ 8,353	$ 8,295
50	1920	**Computer Equip**						$ 5,127		$ 4,899	$ 3,391	$ 4,172	$ 5,004
12	1925	**Computer Software**	$ 5,153	$ 5,807	$ 8,083	$ 8,296	$ 8,380	$ 3,418		$ 3,266			
10	1930	**Transportation Equipment**	$ 66,693	$ 67,081	$ 60,798	$ 47,419	$ 60,677	$ 42,176		$ 42,176	$ 25,988	$ 4,206	$ 9,873
8	1940	**Tools-Misc. Equip.**	$ 7,903	$ 6,837	$ 6,997	$ 7,073	$ 7,152	$ 6,924		$ 6,933	$ 1,754	$ 1,744	$ 2,401
8	1945	**Measurement & Testing**										$ 75	$ 325
8	1955	**Communication Equipment**										$ 45	$ 90
			$ 384,100	**$ 391,605**	**$ 372,046**	**$ 348,721**	**$ 357,117**	**$ 333,633**		**$ 564,032**	**$ 216,119**	**$ 177,093**	**$ 180,791**
		Pooled assets and depreciation were the following: 1808 & 1908, 1840 & 1845, 1920 &1925 (1611)											
		**Fort Frances Municipal Transformer Station was transferred to proper USoA account, 1815 from 1820.*											

The year-over-year fluctuations in amortization expense (as seen above) are natural based on capital additions, disposal of assets, and assets becoming fully depreciated. The increase for 2012 over 2011 is mainly due to the inclusion of Smart Meters in 2012's rate base.

FFPC has provided detailed amortization expense calculations using the OEB's methodology. There are no differences between this methodology and FFPC's Audited Financial Statement amortization amounts.

Depreciation rates are in line with rates as set out in the APH. These rates are reflected in Tables 4.2.29 to 4.2.32 below for the years 2012, 2013 (CGAAP) and 2014 (CGAAP).

Table 4.2.29 – Amortization Expense for 2012

Appendix 2-CR
Depreciation and Amortization Expense
Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013
Year 2012 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 29,094	$ 11,789	$ 17,305	$ 760	$ 17,685	5.00	20.00%	$ 3,537	$ 3,266	$ 271
1612	Land Rights (Formally known as Account 1906)	$ -		$ -		$ -			$ -		$ -
1805	Land	$ 100,000		$ 100,000		$ 100,000	0.00		$ -		$ -
1808	Buildings	$ 823,377	$ 555,434	$ 267,943		$ 267,943	25.00	4.00%	$ 10,718	$ 14,633	-$ 3,915
1810	Leasehold Improvements	$ -		$ -		$ -			$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 1,076,223		$ 1,076,223		$ 1,076,223	40.00	2.50%	$ 26,906	$ 26,133	$ 773
1820	Distribution Station Equipment <50 kV			$ -		$ -			$ -		$ -
1825	Storage Battery Equipment			$ -		$ -			$ -		$ -
1830	Poles, Towers & Fixtures	$ 5,012,449	$ 754,743	$ 4,257,706	$ 157,180	$ 4,336,296	25.00	4.00%	$ 173,452	$ 176,581	-$ 3,129
1835	Overhead Conductors & Devices	$ 401,309	$ 401,309	$ 0		$ 0	25.00	4.00%	$ 0		$ 0
1840	Underground Conduit	$ 2,183		$ 2,183		$ 2,183	25.00	4.00%	$ 87	$ 87	$ 0
1845	Underground Conductors & Devices	$ 89,939		$ 89,939	$ 8,000	$ 93,939	25.00	4.00%	$ 3,758	$ 3,918	-$ 160
1850	Line Transformers	$ 1,195,739	$ 431,757	$ 763,982	$ 13,634	$ 770,799	25.00	4.00%	$ 30,832	$ 30,987	-$ 155
1855	Services (Overhead & Underground)	$ 7,197		$ 7,197		$ 7,197			$ -		$ -
1860	Meters	$ 391,866	$ 391,866	$ -		$ -			$ -	$ 38,356	-$ 38,356
1860	Meters (Smart Meters)			$ -	$ 841,418	$ 841,418	15.00	6.67%	$ 56,095	$ 209,763	-$ 153,668
1905	Land	$ -		$ -		$ -			$ -		$ -
1908	Buildings & Fixtures	$ 394,273	$ 248,358	$ 145,915	$ 10,835	$ 151,333	25.00	4.00%	$ 6,053	$ 74	$ 5,979
1910	Leasehold Improvements	$ 86,122	$ 10,506	$ 75,616		$ 75,616	30.00	3.33%	$ 2,521	$ 2,545	-$ 24
1915	Office Furniture & Equipment (10 years)	$ 117,407	$ 81,373	$ 36,034		$ 36,034	10.00	10.00%	$ 3,603	$ 3,681	-$ 78
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -			$ -		$ -
1920	Computer Equipment - Hardware	$ 45,141	$ 20,645	$ 24,496	$ 1,910	$ 25,451	5.00	20.00%	$ 5,090	$ 4,899	$ 191
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -			$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -			$ -		$ -
1930	Transportation Equipment	$ 696,398	$ 283,089	$ 413,309		$ 413,309	9.75	10.26%	$ 42,391	$ 42,176	$ 215
1935	Stores Equipment	$ -		$ -		$ -			$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 160,416	$ 91,185	$ 69,231	$ 2,283	$ 70,373	10.00	10.00%	$ 7,037	$ 6,933	$ 104
1945	Measurement & Testing Equipment			$ -		$ -			$ -		$ -
1950	Power Operated Equipment			$ -		$ -			$ -		$ -
1955	Communications Equipment			$ -		$ -			$ -		$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -			$ -		$ -
1960	Miscellaneous Equipment			$ -		$ -			$ -		$ -
1970	Load Management Controls - Customer Premises			$ -		$ -			$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -			$ -		$ -
1980	System Supervisor Equipment			$ -		$ -			$ -		$ -
1985	Miscellaneous Fixed Assets			$ -		$ -			$ -		$ -
1990	Other Tangible Property			$ -		$ -			$ -		$ -
1995	Contributions & Grants			$ -		$ -			$ -		$ -
etc.				$ -		$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 10,629,133	$ 3,282,054	$ 7,347,079	$ 1,036,020	$ 8,285,798			$ 372,079	$ 564,032	-$ 191,953

Notes:

- FFPC has a legacy departure from the OEB 'half-life' rule and calculated on full year for additions.
- USoA #1820 – Distribution Station <50kV was reclassified to the correct USoA #1810, Transformer Stations;
- USoA #1830 and #1835, USoA#s 1815 & 1825, USoA#s 1840 & 1845 were pooled. A review was completed in 2013 by BDO Dunwoody Advisory Services to appropriate costs in value based accounts.

Table 4.2.30 – Amortization Expense for 2012 (CGAAP)

Appendix 2-CS
Depreciation and Amortization Expense
Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013
Year 2013 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2013 Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (I)	Variance [2] (m) = (h) - (I)
1611	Computer Software (Formally known as Account 1925)	$ 29,854	$ 11,789	$ 18,065	$ 27,500	$ 31,815	5.00	20.00%	$ 6,363	$ 4,614	$ 1,749
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0.00%	$ -		$ -
1805	Land	$ 100,000		$ 100,000		$ 100,000	0.00	0.00%	$ -		$ -
1808	Buildings	$ 823,377	$ 555,434	$ 267,943	$ 2,000	$ 268,943	25.00	4.00%	$ 10,758	$ 15,153	-$ 4,395
1810	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 1,076,223		$ 1,076,223	$ 2,000	$ 1,077,223	40.00	2.50%	$ 26,931	$ 26,174	$ 757
1820	Distribution Station Equipment <50 kV	$ -		$ -		$ -		0.00%	$ -		$ -
1825	Storage Battery Equipment	$ 9,565		$ 9,565	$ 2,000	$ 10,565	10.00	10.00%	$ 1,057		$ 1,057
1830	Poles, Towers & Fixtures	$ 5,169,630	$ 1,166,745	$ 4,002,885	$ 121,891	$ 4,063,830	25.00	4.00%	$ 162,553	$ 160,847	$ 1,706
1835	Overhead Conductors & Devices	$ 401,309	$ 401,309	-$ 0	$ 14,500	$ 7,250	25.00	4.00%	$ 290		$ 290
1840	Underground Conduit	$ 2,183		$ 2,183		$ 2,183	25.00	4.00%	$ 87		$ 87
1845	Underground Conductors & Devices	$ 97,937		$ 97,937	$ 8,769	$ 102,322	25.00	4.00%	$ 4,093	$ 4,004	$ 89
1850	Line Transformers	$ 1,209,373	$ 566,794	$ 642,579	$ 15,000	$ 650,079	25.00	4.00%	$ 26,003	$ 24,897	$ 1,106
1855	Services (Overhead & Underground)	$ 7,197		$ 7,197	$ 2,000	$ 8,197	25.00	4.00%	$ 328		$ 328
1860	Meters	-$ 0		-$ 0		-$ 0		0.00%	$ -		$ -
1860	Meters (Smart Meters)	$ 841,418		$ 841,418		$ 841,418	15.00	6.67%	$ 56,095	$ 56,094	$ 1
1905	Land	$ -		$ -		$ -		0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 405,109	$ 248,358	$ 156,751	$ 24,000	$ 168,751	25.00	4.00%	$ 6,750	$ 74	$ 6,676
1910	Leasehold Improvements	$ 86,122	$ 10,506	$ 75,616	$ 1,500	$ 76,366	30.00	3.33%	$ 2,546	$ 2,545	$ 1
1915	Office Furniture & Equipment (10 years)	$ 117,407	$ 81,373	$ 36,034	$ 3,000	$ 37,534	10.00	10.00%	$ 3,753	$ 3,729	$ 24
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 47,053	$ 20,645	$ 26,408	$ 5,900	$ 29,358	5.00	20.00%	$ 5,872	$ 3,456	$ 2,416
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment	$ 696,397	$ 483,347	$ 213,050	$ 120,000	$ 273,050	10.00	10.00%	$ 27,305	$ 22,393	$ 4,912
1935	Stores Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 153,134	$ 91,185	$ 61,949	$ 11,500	$ 67,699	10.00	10.00%	$ 6,770	$ 6,808	-$ 38
1945	Measurement & Testing Equipment	$ -		$ -	$ 1,500	$ 750	10.00	10.00%	$ 75	$ 150	-$ 75
1950	Power Operated Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1955	Communications Equipment	$ -		$ -	$ 900	$ 450	5.00	20.00%	$ 90	$ 90	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -		0.00%	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1970	Load Management Controls - Customer Premises	$ -		$ -		$ -		0.00%	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -		0.00%	$ -		$ -
1980	System Supervisor Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -		0.00%	$ -		$ -
1990	Other Tangible Property	$ -		$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants	$ -		$ -		$ -		0.00%	$ -		$ -
etc.				$ -		$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	**$11,273,288**	**$ 3,637,485**	**$ 7,635,803**	**$ 363,960**	**$ 7,817,783**			**$ 347,717**	**$ 331,028**	**$ 16,689**

The table above calculates 2012 CGAAP depreciation based on the January 1, 2012 Net Book Value. Column A-1 in the above table represents the reassessment of FFPC's pooled assets as part of the BDO Canada Ltd, Advisory Services review, where:

- USoA# 1815, Transformer Station was componentized, as shown;
- USoA# 1830, 1835, 1840, and 1845 valuation costs were reallocated to assessed assets;

The 'Average Remaining Useful Life of Opening NBV', was adopted from FFPC's Asset Management Process summary, as noted previously in this exhibit. The 2012 MIFRS depreciation calculation is $216,119, a variance of -$194,245 of the 2012 CGAAP depreciation calculation of $564,032, when adjusted the 2012 Smart Meter amortization was adjusted to a one year amount, $56,094 from the four year amount of $209,763.

Table 4.2.31 – Amortization Expense for 2013 CGAAP

Appendix 2-CT
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2013 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 5,538	$ 27,500	1.20	5.00	20.00%	$ 4,615	$ 2,750	$ 7,365	$ 4,614	$ 2,751	$ 5,500		$ 10,115
1612	Land Rights (Formally known as Account 1906)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land	$ 100,000				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings	$ 81,096	$ 2,000	23.50	62.00	1.61%	$ 3,451	$ 16	$ 3,467	$ 15,153	-$ 11,686	$ 32		$ 3,483
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 138,298	$ 2,000	21.00	62.00	1.61%	$ 6,586	$ 16	$ 6,602	$ 26,174	-$ 19,572	$ 32		$ 6,618
1820	Distribution Station Equipment <50 kV					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment	$ 9,565	$ 2,000	6.00	15.00	6.67%	$ 1,594	$ 67	$ 1,661		$ 1,661	$ 133		$ 1,728
1830	Poles, Towers & Fixtures	$ 1,184,058	$ 121,891	23.21	45.00	2.22%	$ 51,015	$ 1,354	$ 52,369	$ 160,847	-$ 108,478	$ 2,709	$ 16,552	$ 37,172
1835	Overhead Conductors & Devices	$ 400,558	$ 14,500	26.00	60.00	1.67%	$ 15,406	$ 121	$ 15,527		$ 15,527	$ 242		$ 15,648
1840	Underground Conduit	$ 2,183		40.00	60.00	1.67%	$ 55	$ -	$ 55		$ 55	$ -		$ 55
1845	Underground Conductors & Devices	$ 71,774	$ 8,769	13.00	40.00	2.50%	$ 5,521	$ 110	$ 5,631	$ 4,004	$ 1,627	$ 219		$ 5,740
1850	Line Transformers	$ 170,974	$ 15,000	11.21	40.00	2.50%	$ 15,252	$ 188	$ 15,439	$ 24,897	-$ 9,458	$ 375		$ 15,627
1855	Services (Overhead & Underground)	$ 7,197	$ 2,000	7.00	40.00	2.50%	$ 1,028	$ 25	$ 1,053		$ 1,053	$ 50		$ 1,078
1860	Meters					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 631,655		10.00	15.00	6.67%	$ 63,166	$ -	$ 63,166	$ 56,094	$ 7,072	$ -		$ 63,166
1905	Land					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures	$ 151,642	$ 24,000	17.50	40.00	2.50%	$ 8,665	$ 300	$ 8,965	$ 74	$ 8,891	$ 600		$ 9,265
1910	Leasehold Improvements	$ 67,949	$ 1,500	15.00	20.00	5.00%	$ 4,530	$ 38	$ 4,567	$ 2,545	$ 2,022	$ 75		$ 4,605
1915	Office Furniture & Equipment (10 years)	$ 13,728	$ 3,000	5.00	15.00	6.67%	$ 2,746	$ 100	$ 2,846	$ 3,729	-$ 883	$ 200	$ 376	$ 2,570
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 4,309	$ 5,900	2.00	5.00	20.00%	$ 2,155	$ 590	$ 2,745		$ 2,745	$ 1,180	$ 1,309	$ 2,026
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -	$ 3,456	-$ 3,456	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 196,721	$ 120,000	9.00	15.00	6.67%	$ 21,858	$ 4,000	$ 25,858	$ 22,393	$ 3,465	$ 8,000		$ 29,858
1935	Stores Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 13,120	$ 11,500	2.00	10.00	10.00%	$ 6,560	$ 575	$ 7,135	$ 6,808	$ 327	$ 1,150	$ 443	$ 7,267
1945	Measurement & Testing Equipment		$ 1,500	8.00	8.00	12.50%	$ -	$ 94	$ 94	$ 150	-$ 56	$ 188		$ 188
1950	Power Operated Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communications Equipment		$ 900	10.00	10.00	10.00%	$ -	$ 45	$ 45	$ 90	-$ 45	$ 90		$ 90
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1970	Load Management Controls - Customer Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1990	Other Tangible Property					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributions & Grants					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	**$ 3,250,365**	**$ 363,960**				**$ 214,201**	**$ 10,387**	**$ 224,589**	**$ 331,028**	**-$ 106,439**	**$ 20,775**	**$ 18,680**	**$ 216,296**

Table 4.2.32 – Amortization Expense for 2014 Test Year – CGAAP

Appendix 2-CU
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2014 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Depreciation + ((d)*0.5)/(f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 4,000	5.00	20.00%	$ 10,515	$ 6,518	$ 3,997
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -
1805	Land			0.00%	$ -		$ -
1808	Buildings	$ 5,000	62.00	1.61%	$ 3,523	$ 15,923	-$ 12,400
1810	Leasehold Improvements			0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV		62.00	1.61%	$ 6,618	$ 26,214	-$ 19,596
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -
1825	Storage Battery Equipment	$ 2,000	15.00	6.67%	$ 1,794		$ 1,794
1830	Poles, Towers & Fixtures	$ 424,609	45.00	2.22%	$ 41,890	$ 149,321	-$ 107,431
1835	Overhead Conductors & Devices	$ 51,680	60.00	1.67%	$ 16,078		$ 16,078
1840	Underground Conduit	$ 27,000	60.00	1.67%	$ 280	$ 4,544	-$ 4,264
1845	Underground Conductors & Devices	$ 18,549	40.00	2.50%	$ 5,972		$ 5,972
1850	Line Transformers	$ 134,228	40.00	2.50%	$ 17,305	$ 15,329	$ 1,976
1855	Services (Overhead & Underground)	$ 4,000	40.00	2.50%	$ 1,128		$ 1,128
1860	Meters			0.00%	$ -		$ -
1860	Meters (Smart Meters)	$ 5,750	15.00	6.67%	$ 63,357	$ 56,094	$ 7,263
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 7,500	40.00	2.50%	$ 9,359	$ 74	$ 9,285
1910	Leasehold Improvements		20.00	5.00%	$ 4,605	$ 2,515	$ 2,090
1915	Office Furniture & Equipment (10 years)	$ 6,500	15.00	6.67%	$ 2,786	$ 3,778	-$ 992
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware	$ 15,500	5.00	20.00%	$ 3,576	$ 4,533	-$ 958
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment	$ 50,000	15.00	6.67%	$ 31,525	$ 30,293	$ 1,232
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 10,500	10.00	10.00%	$ 7,792	$ 7,315	$ 477
1945	Measurement & Testing Equipment	$ 3,500	8.00	12.50%	$ 406	$ 325	$ 81
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment		10.00	10.00%	$ 90	$ 90	$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -
1970	Load Management Controls - Customer Premises			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -
etc.				0.00%	$ -		$ -
				0.00%	$ -		$ -
	Total	**$ 770,316**			**$ 228,599**	**$ 322,866**	**-$ 94,267**
	Total Depreciation expense to be included in the test year revenue requirement				**$ 228,599**		

TAX CALCULATIONS:

Table 4.3.1 below provides a summary of 2006 Approved, the 2007-2012 Actual, and the 2013 Bridge Year (CGAAP) and 2014 Test Year (CGAAP) income tax estimate using rates prescribed by the OEB in FFPC's 2012 IRM rate decision and order. A copy of FFPC's 2012 annual federal and provincial tax return has been provided as Appendix B to this exhibit. In accordance with the June 2013 filing requirements the Board's PILs model has also been completed and submitted and is consistent with the PILs included in the 2014 revenue requirement.

Table 4.3.1 – Summary of Income Taxes 2006 to 2014

Item	2006	2007	2008	2009	2010	2011	2012	2013	2014
								Bridge	Test
Accounting Net Income Before Taxes	$ 74,073	$ 56,023	-$ 17,155	-$ 56,616	$ 17,052	-$ 36,494	-$313,913	$382,055	$161,744
Additions									
Provision for income taxes current	$ 40,069	$ 32,730	$ 8,970	-$ 1,514	-$ 8,780		-$ 22,453		
Provision for income taxes - deferred	$ 496	-$ 45,177	-$ 14,264						
Amortization of Assets	$384,100	$391,605	$372,046	$348,721	$357,117	$333,632	$564,032	$178,000	$ 179,000
Gain (Loss) on Disposal of Assets		$ 334			$ 1,220	$ 5,127			
Non-Deductable Meals	$ 1,098	$ 3,175	$ 4,114	$ 5,300	$ 5,854		$ 8,367	$ 5,000	
Apprenticeship Tax Credits			$ 8,005	$ 21,670	$ 22,446			$ 7,000	
Miscellaneous Additions		$ 4,986		$ 53,456	$ 8,790		$ 22,510		
Deductions									
Provision-recovery of current income tax							$ 22,453		
Captial Cost Allowance from Schedule 8	$249,098	$238,731	$230,267	$251,922	$333,552	$364,895	$351,728	$333,113	$ 341,183
Gain (Loss) on Disposal of Assets	$ 35,000	$ 2,390							
Cumulative eligible capital deductions	$ 546		$ 4,325						
Income for Tax Purposes	$215,192	$202,555	$127,124	$119,095	$ 70,147	-$ 62,630	-$ 93,185	$238,942	-$ 439
Tax Rate	*38%*	*38%*	*38%*	*38%*	*38%*	*38%*	$ -	*38%*	
Federal Tax	$ 81,773	$ 76,971	$ 48,307	$ 45,256	$ 26,656	$ -	$ -	$ 90,798	
Surtax	$ 2,410	$ 2,269							
Small Business Deduction	-$ 34,431	-$ 32,409	-$ 21,611	-$ 20,246	-$ 11,925			-$ 38,231	
Federal Tax Abatement/Other	-$ 21,519	-$ 20,256	-$ 12,712	-$ 11,910	-$ 7,015			-$ 23,607	
Provincial Tax	$ 11,836	$ 6,155		$ 6,550	$ 9,113				
Ontario Small Business Deduction					-$ 5,609				
Less: Apprenticeship Tax Credit				-$ 17,670	-$ 20,000	-$ 10,849	-$ 7,077	-$ 7,000	$ -
Less: Innovation Tax Credit						-$ 13,434			
Investment Tax Credit			-$ 4,000	-$ 2,446		-$ 42,318			
Total Tax Payable	$ 40,069	$ 32,730	$ 9,984	-$ 466	-$ 8,780	-$ 66,601	-$ 7,077	$ 21,960	$ -

Detailed calculations of FFPC's PILs are provided in the 2014 Test Year Income Tax PILs Workform V2 filed with this Application.

FFPC's detailed tax calculations using the most recent tax rates are provided in Table 4.3.2. No Capital Tax is paid effective July, 2010. FFPC has maintained a zero tax rate that has been used for 2014 consistent with the tax rate suggested in FFPC's PIL tax work form.

Table 4.3.2: Schedule of Corporate Tax Rates 2013 and 2014

Corporate Tax Rates for Tax Year	2013 Bridge	2014 Test
Federal Income Tax	15.00%	0.00%
Ontario Income Tax	11.50%	0.00%
Combined Income Tax	26.50%	0.00%
Small Business Threshold	500,000	500,000
Federal Small Business Rate	11.00%	0.00%
Ontario Small Business Rate	4.50%	0.00%
Combined Small Business Rate	15.50%	0.00%

CAPITAL COST ALLOWANCE:

FFPC is providing Capital Cost Allowance continuity schedules for the 2013 Bridge Year-CGAAP (Tables 4.3.3) and the 2014 Test Year (CGAAP) (Tables 4.3.4) as follows:

Table 4.3.3 – 2013 CCA Continuity Schedule

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 2,999,877			$ 2,999,877	$ -	$ 2,999,877	4%	$ 119,995	$ 2,879,882
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 257,676			$ 257,676	$ -	$ 257,676	4%	$ 10,307	$ 247,369
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 355,227	$ 16,900		$ 372,127	$ 8,450	$ 363,677	20%	$ 72,735	$ 299,392
10	Computer Hardware/ Vehicles	$ 451	$ 125,900	-$ 107,038	$ 19,313	$ 9,431	$ 9,882	30%	$ 2,965	$ 16,348
10.1	Certain Automobiles	$ 123,175			$ 123,175	$ -	$ 123,175	30%	$ 36,953	$ 86,223
12	Computer Software	$ 380			$ 380	$ -	$ 380	100%	$ 380	$ -
13 1	Lease # 1	$ 37,777			$ 37,777	$ -	$ 37,777	4%	$ 1,511	$ 36,266
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 294			$ 294	$ -	$ 294	45%	$ 132	$ 162
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 894,504	$ 192,160		$ 1,086,664	$ 96,080	$ 990,584	8%	$ 79,247	$ 1,007,417
50	Data Network Infrastructure Equipment - post Mar 2007	$ 2,410	$ 27,500		$ 29,910	$ 13,750	$ 16,160	55%	$ 8,888	$ 21,022
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 4,671,771	$ 362,460	-$ 107,038	$ 4,927,193	$ 127,711	$ 4,799,482		$ 333,113	$ 4,594,080

Table 4.3.4 – 2014 CCA Schedule

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 2,879,882			$ 2,879,882	$ -	$ 2,879,882	4%	$ 115,195	$ 2,764,687
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 247,369			$ 247,369	$ -	$ 247,369	4%	$ 9,895	$ 237,474
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 299,392	16,500		$ 315,892	$ 8,250	$ 307,642	20%	$ 61,528	$ 254,363
10	Computer Hardware/ Vehicles	$ 16,348	45,500	-21,142	$ 40,706	$ 12,179	$ 28,527	30%	$ 8,558	$ 32,148
10.1	Certain Automobiles	$ 86,223			$ 86,223	$ -	$ 86,223	30%	$ 25,867	$ 60,356
12	Computer Software	$ -			$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1	$ 36,266			$ 36,266	$ -	$ 36,266	4%	$ 1,451	$ 34,815
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Tha	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 162			$ 162	$ -	$ 162	45%	$ 73	$ 89
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 1,007,417	647,768		$ 1,655,185	$ 323,884	$ 1,331,301	8%	$ 106,504	$ 1,548,681
50	Data Network Infrastructure Equipment - post Mar 2007	$ 21,022	2,000		$ 23,022	$ 1,000	$ 22,022	55%	$ 12,112	$ 10,910
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 4,594,080	$ 711,768	-$ 21,142	$ 5,284,706	$ 345,313	$ 4,939,393		$ 341,183	$ 4,943,523

FFPC did not have entries in the Cumulative Eligible Capital Continuity schedules of the 2013 Bridge and Test 2014 year.

Other Taxes:

The table below details FFPC's property tax history.

Acct	Name	2006	2007	2008	2009	2010	2011	2012	2013	2014
									Bridge	Test
6105	Property Taxes	$ 14,525	$ 14,652	$ 14,638	$ 14,092	$ 12,775	$ 12,484	$ 12,264	$ 13,000	$ 13,000

MIFRS CONVERSION

Conversion to Modified International Financial Reporting Standards (MIFRS)

Upon the advice of our auditors, BDO Canada LLP, FFPC will defer the transition to IFRS until the Accounting Standards Board (AcSB) has made a final decision on whether rate-regulated entities will actually be required to adopt, which currently has been deferred until January 1, 2015.

MIFRS – IMPACT ON OM&A

FFPC does not foresee a material change to OM&A as a result of the conversion to MIFRS.

MIFRS – IMPACT ON DEPRECIATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of assets' useful lives, depreciation methods and residual values on an annual basis.

The Board commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to International Financial Reporting Standards, (EB-2008-0408) the Board stated:

> "While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the

service lives for their particular assets for financial reporting and regulatory requirements."

FFPC has moved our capitalization policy to be consistent with CGAAP and has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinectrics (Kinectrics Report) and through further analysis of FFPC's asset by BDO Canada Ltd's Advisory Services Assessment and FFPC's Distribution System Plan and Asset Management Policy. FFPC has determined LDC specific 'Useful Lives' based on comprehensive conditional assessment. Table 2.5.1 included in Exhibit 2, Tab 5, Schedule 1 contains the useful lives by Uniform System of Account, compared to the current useful lives used under CGAAP. FFPC has through this review, found the useful lives have been extended causing depreciation to be reduced in the 2014 Test year by $94,267, from $322,866 under existing CGAAP to $228,599 under new capitalization policy.

Below is a summary table of FFPC's 'Adopted Useful Life' based on FFPC's Asset Management Plan detailed in Exhibit 2.

FFPC Summary of Assets Owned

		Asset Details			Kinectrics Useful Life			Useful Life Assessment	
Parent*	USoA Account #	#	Category| Component | Type		MIN UL	TUL	MAX UL	FFPC Adopted Useful Life (UL)	Remaining Useful Life Relative to FFPC Adopted UL
OH	1830	1	Fully Dressed Wood Poles	Overall	35	45	75	45	23.21
		4	OH Line Switch (Expressed as sets of 3 Phase Switches)		30	45	55	45	20.66
	1835	8	OH Conductors	Primary Conductor	50	60	75	60	26.23
	1855			Secondary Conductor	25	35	40	40	12.00
	1850	9	OH Transformers		30	40	60	40	11.21
TS & MS		12	Power Transformers	Overall	30	45	60	58	20.00
	1815			Bushing	10	20	30	44	6.00
	(all)			Tap Changer	20	30	60	58	20.00
		13	Station Service Transformer		30	45	55	45	5.00
		15	Station DC System	Overall	10	20	30	29	6.00
				Battery Bank	10	15	15	15	6.00
				Charger	20	20	30	29	6.00
		16	Station Metal Clad Switchgear	Overall	30	40	60	62	17.00
				Removable Breaker	25	40	60	62	17.00
		17	Station Independent Breakers		35	45	65	71	4.00
		18	Station Switch		30	50	60	62	21.00
		19	Electromechanical Relays		25	35	50	45	9.00
		21	Digital & Numeric Relays		15	20	20	20	18.50
		22	Rigid Busbars		30	55	60	62	26.00
		23	Steel Structure		35	50	90	62	26.00
UG	1840	29	Primary TR XLPE Cables in Duct		35	40	55	40	12.93
	1855	31	Secondary Cables Direct Buried		25	35	40	35	7.00
	1850	34	Pad-Mounted Transformers	Single Phase	25	40	45	40	12.30
	1850			Three Phase	25	40	45	40	19.95
	1850	36	UG Foundation		35	55	70	80	52.48
	1840	40	Ducts		30	50	85	80	52.05
	1840	41	Concrete Encased Duct Banks		35	55	80	80	46.54
	1840	42	Cable Chambers		50	60	80	60	39.60
General Plant	1915	1	Office Equipment		5-15			5-20	Various
	1930	2	Vehicles	Trucks & Buckets	5-15			15	7.00
				Trailers	5-20			20	-6.00
	1908	3	Administrative Buildings		50-75			75	30.00
	1910	4	Leasehold Improvements (Generator)		20			20	15.00
	1808	5	Station Buildings	Station Buildings	50-75			62	23.00
				Parking	25-30			30	6.00
				Fence	25-60			62	20.00
				Roof	20-30			40	1.00
	1920	6	Computer Equipment	Hardware	3-5			5	Various
	1611			Software	2-5			5	Various
	1940	7	Equipment	Power Operated	5-10			7	Various
	1940			Tools, Shop, Garage Eq	5-10			10	Various
	1945			Measurement &	5-10			8	Various
				Wireless	2-10			10	Various
	1860	11	Wholesale Energy Meters		15-30			9	4.00
	1860	12	Current & Potential Transformer (CT & PT)		35-50			40	Various
	1860	13	Smart Meters		5-15			15	10.08
	1860	15	Data Collectors - Smart Metering		15-20			17	12.00

MIFRS – IMPACT ON TAXES

TAX CALCULATIONS:

FFPC will defer the transition to IFRS until the Accounting Standards Board (AcSB) has made a final decision on whether rate-regulated entities will actually be required to adopt, which currently has been deferred until January 1, 2015.

As indicated prior depreciation under the former CGAAP cost calculations for the year 2014 would have been $322,866. The lower depreciation expense for the new CGAAP calculation is $228,599. The increased revenue would increase regulatory income and the PILS calculation would also be greater.

INTEGRITY CHECKS

This is a statement confirming the following integrity checks have been completed to:

- The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application;
- The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historic, bridge and test years;
- Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st of $4,671,771.
- The CCA deductions in the application's PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application;
- Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application, the amount being $18,660;
- CCA is maximized even if there are tax loss carry-forwards;
- FFPC may utilize the losses in tax year 2013 if a year end profit is realized;
- As FFPC has no further OPEB than the accumulated sick leave payout mentioned prior, the Schedule 1 reconciliation of accounting income to net income for tax purposes agree with the OM&A analysis for compensation.
- The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.

EXHIBIT FOUR

APPENDIX A

Fort Frances Power Corporation's Purchasing Policy

FFPC
FORT FRANCES POWER CORPORATION

APPENDIX A

Fort Frances Power Corporation Purchasing Policy

CONTRACT NEGOTIATION AND PURCHASING POLICY

PURPOSE AND APPLICABILITY

To set forth the policy of the company regarding the negotiation of contracts and prescribe the approval procedure for purchasing authorizing major expenditures for repairs, inventory items, capital acquisitions, legal fees, environmental costs, outside consultants and services, leases, etc.

POLICY STATEMENT

It is the policy of Fort Frances Power Corporation to set up procedures for the negotiation of contracts and the purchasing of supplies, materials and other services on behalf of the Company. Further, it is the Policy of Fort Frances Power Corporation that an annual budget be approved by the Board of Directors for capital and non-capital expenditures.

PROCEDURE AND RESPONSIBILITY

A. Contract Negotiation:

Contracts – The CEO in conjunction with the appropriate management staff shall have the authority to negotiate all legally binding contracts on behalf of the Board of Directors and the Corporation. All legally binding contracts shall be approved by the Board of Directors prior to their execution and shall be signed by the CEO and the Chair of the Board of Directors.

B. Purchasing - General

The CEO and appropriate management staff shall have the authority to purchase within their prescribed limits, all items included in the annual budget approved by the Board of Directors.

All budgeted items greater than $5,000 shall be approved by the CEO.

All major purchases greater than $50,000 shall be approved by the Board of Directors. (***Note to Board - $50,000 dollar amount aligns with the OEB “Materiality Threshold” for a utility our size***)

Any purchases not included in the budget, greater than $500 but less than $5,000 must be approved by the CEO.

Any purchases greater than $5,000 not included in the budget shall be approved by the Board of Directors.

C. Procedure and Responsibility

It is the joint responsibility of both the CEO and management staff, to ensure proper approvals for all transactions are received.

It is the responsibility of the Board of Directors to adopt the annual operating and capital budgets. These annual budgets shall represent fundamental statements of Fort Frances Power Corporation policies and priorities. These budgets (and in particular, the operating budget) shall be recognized as a policy document and an instrument of financial management and control.

D. Purchasing Procedure & Purchase Order Levels

Purchase Level: Less than $500

No purchase order is required for expenditures below $500 but approval and account coding is required.

Purchase Level: Greater than $500

All purchases greater than $500 must be acquired using purchase orders. Purchase orders will be approved by the CEO for budgeted operational expenses/capital projects and rework, validated for appropriateness of expenditure and checked for accuracy.

Quotes:

The CEO in conjunction with management staff are responsible for establishing qualified vendors for all purchases. The following purchasing quotation process shall be used:

i. Purchases Under $15,000 in Aggregate Value: Competitive quotes will be obtained to determine the pricing structures for goods and services regularly used for the operation of the Corporation. Competitive quotes will be obtained at a minimum three year interval, or sooner in the event of a significant price change.

ii. Purchases Between $15,000 - $50,000 in Aggregate Value: A minimum of three quotes in writing will be required. In the event that fewer than three suitable

quotes can be obtained, the CEO shall have the discretion of proceeding with the purchase based on the quotes received.

iii. $50,000 and over in Aggregate Value. A minimum of three quotes or tenders will be solicited by invitation or through a public advertisement by the CEO. The CEO shall supervise the tender preparation and the awarding process. The quotes or tenders shall be opened in the presence of the CEO and Board of Director representation. In the event that fewer than three suitable quotes or tenders can be obtained, the Board of Directors shall have the discretion of whether or not to proceed with the quotes or tenders received. The CEO will review the quote or tender results, and will make recommendations to the Board for their approval.

iv. As an alternative to the Tendering process, a sealed Quotation may be used. In all other respects, the process is the same.

a. For quotes or tenders over $50,000 which exceed budgeted amounts, Board approval must be obtained.

b. Records of comparative pricing will be kept for a period up to three years, at which time new quotes will be requested as required.

c. Notwithstanding the requirements of sections D.i through D.iii, an allowance is made for pre-approved contractors, designated sole suppliers of certain goods or services and/or ongoing phased projects.

E. Purchasing Procedure

The purchasing procedure under Regulation 22/04 of the Electricity Act, 1998, is as follows:

1. Purchase order is placed with pre-approved major equipment supplier noting that Regulation 22/04 compliance is a condition of sale. When applicable, the equipment selected is as per USF Material Specifications.

2. Material received is inspected by a competent person for:
   - Material received is the same as material ordered
   - Material is suitable for the application
   - Material is not damaged and does not pose an undue hazard
   - Material is Regulation 22/04 Compliant (Approved by Certification Organization)
   - Applicable Certification Report is on hand

- Material supplier has supplied list of Industry Standards met that can be cross-referenced to USF or ESA specifications.

3. Shipping Invoice is stamped and dated (see sample below).



4. All related purchasing documentation is filed for easy reference including; purchase order, material certification / test reports. A major equipment file is kept containing all relevant documentation as evidence of O.Reg.22/04 compliance.

5. In the event that the material received does not satisfy sections 1 and 2, the item(s) shall be deemed Not Acceptable and shall be returned to the supplier if a remedy for compliance to sections 1 and 2 cannot be achieved within a reasonable timeframe.

6. FFPC maintains an approved equipment list based on suggested USF material specifications. This listing shall be reviewed at least every second year to ensure that material specifications are up to date.

POLICY COMPLIANCE

All current practices will comply with the OEB Accounting Procedures Handbook and the CICA Handbook. It is the responsibility of the CEO to ensure that all employees are aware of this policy and that it is followed. Employees have a joint responsibility in that they must report incidents of non-compliance relating to this policy in a timely manner to the CEO for determination.

EXHIBIT FOUR

A P P E N D I X B

2012 Federal and Provincial Income Tax Return

And PILs Assessment

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

EXEMPT FROM TAX

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 **Do not use this area**

Identification

Business number (BN) 001 86420 5893 RC0001

Corporation's name

002 Fort Frances Power Corporation

Address of head office

Has this address changed since the last time we were notified? . . . . . 010 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018.)

011 320 Portage Avenue

012

City	Province, territory, or state
015 Fort Frances	016 ON
Country (other than Canada)	**Postal code/Zip code**
017 CA	018 P9A 3P9

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 020 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028.)

021 c/o

022 320 Portage Avenue

023

City	Province, territory, or state
025 Fort Frances	026 ON
Country (other than Canada)	**Postal code/Zip code**
027 CA	028 P9A 3P9

Location of books and records

Has the location of books and records changed since the last time we were notified? . . . . . 030 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038.)

031 320 Portage Avenue

032

City	Province,territory, or state
035 Fort Frances	036 ON
Country (other than Canada)	**Postal code/Zip code**
037 CA	038 P9A 3P9

040 Type of corporation at the end of the tax year

1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2012-01-01 YYYY MM DD	061 2012-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . 063 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . . 065 YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:

subparagraph 88(2)(a)(iv)? . . . . . 064 1 Yes ☐ 2 No ☒

subsection 249(3.1)? . . . . . 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes ☐ 2 No ☒

Amalgamation? . . . . . 071 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . . 078 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☒ Exempt under other paragraphs of section 149

Do not use this area

095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical Energy	285	99.000 %
286	Other	287	1.000 %
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible (YYYY MM DD)	294		
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300	-93,185	A
Deduct: Charitable donations from Schedule 2	311		
Gifts to Canada, a province, or a territory from Schedule 2	312		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction*	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal		▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360		
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 ..... 400 _____ A

Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax ..... 405 _____ B

Business limit (see notes 1 and 2 below) ..... 410 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 ***** _____ D = ... _____ E
11,250

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") ..... 425 500,000 F

Small business deduction

Amount A, B, C, or F, whichever is the least _____ x 17 % = ... 430 _____ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3* ..... A

Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 ..... B

Amount QQ from Part 13 of Schedule 27 C

Personal service business income** ..... 432 D

Amount used to calculate the credit union deduction from Schedule 17 ..... E

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least ..... F

Aggregate investment income from line 440 on page 6*** ..... G

Total of amounts B to G ..... ▶ H

Amount A **minus** amount H (if negative, enter "0") I

Amount I x (Number of days in the tax year before January 1, 2011 / Number of days in the tax year) x 10 % = J

Amount I x (Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year) x 11.5 % = K

Amount I x (Number of days in the tax year after December 31, 2011 / Number of days in the tax year) x 13 % = L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L ..... M

Enter amount M on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies) ..... N

Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27 ..... O

Amount QQ from Part 13 of Schedule 27 ..... P

Personal service business income* ..... 434 Q

Amount used to calculate the credit union deduction from Schedule 17 ..... R

Total of amounts O to R ..... ▶ S

Amount N **minus** amount S (if negative, enter "0") ..... T

Amount T x (Number of days in the tax year before January 1, 2011 / Number of days in the tax year) x 10 % = U

Amount T x (Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year) x 11.5 % = V

Amount T x (Number of days in the tax year after December 31, 2011 / Number of days in the tax year) x 13 % = W

General tax reduction – Total of amounts U to W X

Enter amount X on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 ..... 440 _____ x 26 2 / 3 % = _____ A

Foreign non-business income tax credit from line 632 on page 7 ..... _____

Deduct:

Foreign investment income from Schedule 7 ..... 445 _____ x 9 1 / 3 % = _____

(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") ..... _____ C

Taxable income from line 360 on page 3 ..... _____

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least ..... _____

Foreign non-business income tax credit from line 632 on page 7 ... _____ x 25/9* 100 / 35 = _____

Foreign business income tax credit from line 636 on page 7 ..... _____ x 1(0.38 - X**) 4 = _____

_____ ▶ _____

x 26 2 / 3 % = _____ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) ..... _____ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least ..... 450 _____ F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year ..... 460 _____

Deduct: Dividend refund for the previous tax year ..... 465 _____

_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above ..... _____

Total Part IV tax payable from Schedule 3 ..... _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation ..... 480 _____

_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H ..... 485 _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 ..... _____ x 1 / 3 _____ I

Refundable dividend tax on hand at the end of the tax year from line 485 above ..... _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) ..... _____

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % **550** _____ A

Recapture of investment tax credit from Schedule 31 . . . . . **602** _____ B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 i

Taxable income from line 360 on page 3 . . . . . _____

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . _____

Net amount . . . . . ▶ _____ ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** _____ C

Subtotal (**add** lines A to C) _____ D

Deduct:

Small business deduction from line 430 on page 4 1

Federal tax abatement **608**

Manufacturing and processing profits deduction from Schedule 27 . . . . . **616**

Investment corporation deduction **620**

Taxed capital gains **624** _____

Additional deduction – credit unions from Schedule 17 . . . . . **628**

Federal foreign non-business income tax credit from Schedule 21 . . . . . **632**

Federal foreign business income tax credit from Schedule 21 . . . . . **636**

General tax reduction for CCPCs from amount M on page 5 . . . . . **638**

General tax reduction from amount X on page 5 . . . . . **639**

Federal logging tax credit from Schedule 21 . . . . . **640**

Federal qualifying environmental trust tax credit **648**

Investment tax credit from Schedule 31 . . . . . **652**

Subtotal _____ ▶ _____ E

Part I tax payable – Line D **minus** line E . . . . . _____ F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
	Total federal tax	

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765	
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		
	Total tax payable 770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
	Total credits 890	B

Refund code 894 1 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 Ruppenstein (Last name (print)) 951 Joerg (First name (print)) 954 CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2013-04-26 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (907) 274-9291 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name (print) 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	4,835,042	5,215,480
	Total tangible capital assets	2008	+	11,273,287	10,629,133
	Total accumulated amortization of tangible capital assets	2009	–	8,022,923	7,758,541
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	413,158	1,043,641
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	8,498,564	9,129,713
Liabilities					
	Total current liabilities	3139	+	2,020,482	2,474,054
	Total long-term liabilities	3450	+	1,184,029	1,047,693
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	3,204,511	3,521,747
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	5,294,053	5,607,966
	Total liabilities and shareholder equity	3640	=	8,498,564	9,129,713
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	-513,338	-199,425

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

Income statement information

Description	GIFI

Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	8,889,305	7,633,333
	Cost of sales	8518	–	7,148,968	6,187,827
	Gross profit/loss	8519	=	1,740,337	1,445,506
	Cost of sales	8518	+	7,148,968	6,187,827
	Total operating expenses	9367	+	2,388,253	1,826,288
	Total expenses (mandatory field)	9368	=	9,537,221	8,014,115
	Total revenue (mandatory field)	8299	+	9,200,855	7,990,095
	Total expenses (mandatory field)	9368	–	9,537,221	8,014,115
	Net non-farming income	9369	=	-336,366	-24,020
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	-336,366	-24,020
	Total other comprehensive income	9998	=		
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	-22,453	-18,585
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	-313,913	-5,435

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation?	095	1 Yes	X	2 No	
Is the accountant connected* with the corporation?	097	1 Yes		2 No	X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	1 Yes		2 No	X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Were notes to the financial statements prepared?	101	1 Yes	X	2 No	

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes?	104	1 Yes	X	2 No	
Is re-evaluation of asset information mentioned in the notes?	105	1 Yes		2 No	X
Is contingent liability information mentioned in the notes?	106	1 Yes	X	2 No	
Is information regarding commitments mentioned in the notes?	107	1 Yes		2 No	X

Does the corporation have investments in joint venture(s) or partnership(s)?	108	1 Yes		2 No	X

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . 250 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

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Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				-313,913 A
Add:				
Provision for income taxes – current	101	-22,453		
Amortization of tangible assets	104	564,032		
Non-deductible meals and entertainment expenses	121	8,367		
Subtotal of additions		549,946 ▶		549,946
Other additions:				
Resource amounts deducted	232			
Miscellaneous other additions:				
600 Unrealized loss on investments	290	16,173		
601 Increase in Vested sick leave liability	291	1,431		
604 2012 Ontario Apprenticeship Tax Credit 4,906				
Total 4,906	294	4,906		
Subtotal of other additions	199	22,510 ▶		22,510
Total additions	500	572,456 ▶		572,456 B
Amount A **plus** amount B				258,543
Deduct:				
Capital cost allowance from Schedule 8	403	351,728		
Subtotal of deductions		351,728 ▶		351,728
Other deductions:				
Miscellaneous other deductions:				
704				
Total	394			
Subtotal of other deductions	499	0 ▶		0
Total deductions	510	351,728 ▶		351,728
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-93,185

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business number	Tax year-end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time. Also, no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			-93,185 A
Deduct: (increase a loss)			
Net capital losses deducted in the year (enter as a positive amount)		a	
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)		b	
Amount of Part VI.1 tax deductible		c	
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		d	
Subtotal (total of amounts a to d)	▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")			-93,185 C
Deduct: (increase a loss)			
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			D
Subtotal (amount C **minus** amount D)			-93,185 E
Add: (decrease a loss)			
Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss. Enter amount F on line 310)			F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0"; if negative, enter amount G on line 110 as a positive)			-93,185 G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e	
Deduct: Non-capital loss expired*	100		f	
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102	▶		H
Add:				
Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	105		g	
Current-year non-capital loss (amount G above)	110	93,185	h	
Subtotal (amount g **plus** amount h)		93,185 ▶		93,185 I
Subtotal (amount H **plus** amount I)				93,185 J

* A non-capital loss expires as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

Amount J from page 1 — 93,185

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i
Section 80 – Adjustments for forgiven amounts	140		j
Subsection 111(10) – Adjustments for fuel tax rebate			j.1
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 Return)	130		k
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 330 and 335 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	135		l
Subtotal (total of amounts i to l) ▶			K
Non-capital losses before any request for a carryback (amount J **minus** amount K)		93,185	L

Deduct – Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901		m
Second previous tax year to reduce taxable income	902		n
Third previous tax year to reduce taxable income	903	93,185	o
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r) ▶		93,185	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180		N

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	18,660	a
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		b
Subtotal (amount a **plus** amount b) ▶		18,660	A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	250		c
Section 80 – Adjustments for forgiven amounts	240		d
Subtotal (amount c **plus** amount d) ▶			B
Subtotal (amount A **minus** amount B)		18,660	C
Add: Current-year capital loss (from the calculation on Schedule 6)	210		D
Unused non-capital losses that expired in the tax year*			e
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			f
Enter amount e or f, whichever is less	215		
ABILs expired as non-capital loss: line 215 **divided** by 0.500000	220		E
Subtotal (total of amounts C to E)		18,660	F

Note

If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Amount F from page 2 — 18,660

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1) . . . . . 225 — G

Capital losses before any request for a carryback (amount F **minus** amount G) — 18,660 H

Deduct – Request to carry back capital loss to (see Note 2):

		Capital gain (100%)		Amount carried back (100%)	
First previous tax year	951				g
Second previous tax year	952				h
Third previous tax year	953				i
Subtotal (total of amounts g to i)			▶		I

Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I) 280 — 18,660 J

Note 1

To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2

On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . . . a

Deduct: Farm loss expired* . . . . . 300 — b

Farm losses at the beginning of the tax year (amount a **minus** amount b) . . . . . 302 ▶ — A

Add:

Farm losses transferred on the amalgamation or the windup of a subsidiary corporation . . . . . 305 — c

Current-year farm loss . . . . . 310 — d

Subtotal (amount c **plus** amount d) ▶ — B

Subtotal (amount A **plus** amount B) — C

Deduct:

Other adjustments (includes adjustments for an acquisition of control) . . . . . 350 — e

Section 80 – Adjustments for forgiven amounts . . . . . 340 — f

Farm losses of previous tax years applied in the current tax year (enter on line 334 of the T2 Return) . . . . . 330 — g

Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 340 and 345 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively) . . . . . 335 — h

Subtotal (total of amounts e to h) ▶ — D

Farm losses before any request for a carryback (amount C **minus** amount D) — E

Deduct – Request to carry back farm loss to:

First previous tax year to reduce taxable income . . . . . 921 — i

Second previous tax year to reduce taxable income . . . . . 922 — j

Third previous tax year to reduce taxable income . . . . . 923 — k

First previous tax year to reduce taxable dividends subject to Part IV tax . . . . . 931 — l

Second previous tax year to reduce taxable dividends subject to Part IV tax . . . . . 932 — m

Third previous tax year to reduce taxable dividends subject to Part IV tax . . . . . 933 — n

Subtotal (total of amounts i to n) ▶ — F

Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) 380 — G

* A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business . . . . . 485 _____ A

Minus the deductible farm loss:

(amount A above _____ − $2,500) **divided** by 2 = _____ a

Amount a or $ 6,250 , whichever is less . . . . . _____ ▶ _____ b

2,500 c

Subtotal (amount b **plus** amount c) 2,500 ▶ 2,500 B

Current-year restricted farm loss (amount A **minus** amount B; enter amount C on line 410) _____ C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year . . . . . _____ d

Deduct: Restricted farm loss expired* . . . . . 400 _____ e

Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) . . . . . 402 _____ ▶ _____ D

Add:

Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation . . . . . 405 _____ f

Current-year restricted farm loss (enter on line 233 of Schedule 1) . . . . . 410 _____ g

Subtotal (amount f **plus** amount g) _____ ▶ _____ E

Subtotal (amount D **plus** amount E) _____ F

Deduct:

Restricted farm losses from previous tax years applied against current farming income (enter on line 333 of the T2 Return) . . . . . 430 _____ h

Section 80 – Adjustments for forgiven amounts . . . . . 440 _____ i

Other adjustments . . . . . 450 _____ j

Subtotal (total of amounts h to j) _____ ▶ _____ G

Restricted farm losses before any request for a carryback (amount F **minus** amount G) _____ H

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income . . . . . 941 _____ k

Second previous tax year to reduce farming income . . . . . 942 _____ l

Third previous tax year to reduce farming income . . . . . 943 _____ m

Subtotal (total of amounts k to m) _____ ▶ _____ I

Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) 480 _____ J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year		a	
Deduct: Listed personal property loss expired after seven tax years	500	b	
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502 ▶		A
Add: Current-year listed personal property loss (from Schedule 6)	510		B
Subtotal (amount A **plus** amount B)			C

Deduct:

Previous year personal property losses applied in the current tax year against listed personal property gains (enter on line 655 of Schedule 6)	530	c	
Other adjustments	550	d	
Subtotal (amount c **plus** amount d)	▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)			E

Deduct – Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961	e	
Second previous tax year to reduce listed personal property gains	962	f	
Third previous tax year to reduce listed personal property gains	963	g	
Subtotal (total of amounts e to g)	▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)	580		G

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier 600	Tax year ending YYYY/MM/DD 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6) 620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier 630	Tax year ending YYYY/MM/DD 632	Limited partnership losses at the end of the previous tax year 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664	Current-year limited partnership losses (from column 620) 670	Limited partnership losses applied in the current year (cannot be more than column 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (662 + 664 + 670 – 675) 680

Total (enter this amount on line 335 of the T2 return)

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . . 190 Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	93,185		93,185	N/A		
1st preceding taxation year 2011-12-31		N/A		N/A			
2nd preceding taxation year 2010-12-31		N/A		N/A			
3rd preceding taxation year 2009-12-31		N/A		N/A			
4th preceding taxation year 2008-12-31		N/A		N/A			
5th preceding taxation year 2007-12-31		N/A		N/A			
6th preceding taxation year 2006-12-31		N/A		N/A			
7th preceding taxation year 2005-12-31		N/A		N/A			
8th preceding taxation year 2004-12-31		N/A		N/A			
9th preceding taxation year 2003-12-31		N/A		N/A			
10th preceding taxation year 2002-12-31		N/A		N/A			
11th preceding taxation year 2001-12-31		N/A		N/A			
12th preceding taxation year 2000-12-31		N/A		N/A			
13th preceding taxation year		N/A		N/A			
14th preceding taxation year		N/A		N/A			
15th preceding taxation year		N/A		N/A			
16th preceding taxation year		N/A		N/A			
17th preceding taxation year		N/A		N/A			
18th preceding taxation year		N/A		N/A			
19th preceding taxation year		N/A		N/A			
20th preceding taxation year		N/A		N/A			*
Total		93,185		93,185			

*** This balance expires this year and will not be available next year.**

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? 101 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	Buildings	257,353	10,834		0	5,417	262,770	4	0	0	10,511	257,676
2.	1	Distribution Equip	3,124,872			0		3,124,872	4	0	0	124,995	2,999,877
3.	8	Other Equipment	256,450	159,463		0	79,732	336,181	20	0	0	67,236	348,677
4.	8	Office Equipment	8,188			0		8,188	20	0	0	1,638	6,550
5.	10	Automotive Equipment	175,965			0		175,965	30	0	0	52,790	123,175
6.	10	Computer Hdwe	645			0		645	30	0	0	194	451
7.	45	Computer Equipment & Systems	534			0		534	45	0	0	240	294
8.	13	LEASEHOLD	52,900			0		52,900	NA	0	0	15,123	37,777
9.	47	Transmission & Distribution Asse	949,712	21,634		0	10,817	960,529	8	0	0	76,842	894,504
10.	50	Computer Hardware	2,279	1,910		0	955	3,234	55	0	0	1,779	2,410
11.	12	Computer Software		760		0	380	380	100	0	0	380	380
		Totals	4,828,898	194,601			97,301	4,926,198				351,728	4,671,771

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		194,601		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Other (specify):				
Smart Meters Capitalized for Accounting Puposes in 2012	+	841,419		
Total additions per books	=	1,036,020	▶	1,036,020
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
Stranded Meters Reallocated to RSVA Account	+	92,216		
Total proceeds per books	=	92,216	▶	92,216
Depreciation and amortization per accounts – Schedule 1			–	564,032
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	379,772

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		3,150,364
Opening net book value	–	2,770,592
Net change per financial statements	=	379,772

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	TOWN OF FORT FRANCES (Corporation)	NR			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Fort Frances Power Corporation	86420 5893 RC0001	2012-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Fort Frances Power Corporation

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-06-19	1424338

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
320	Portage Avenue	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Fort Frances	ON	CA	P9A 3P9

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Ruppenstein (Last name) **451** Joerg (First name)

454 _____ (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . . Fort Frances Power Corporation

Taxation Year . . . . . 2012-01-01 to 2012-12-31

Jurisdiction . . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . . N

Corporation is related . . . . . N

Number of associated corporations . . .

Type of corporation . . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . . .

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	-93,185
Taxable income	
Donations	
Calculation of income from an active business carried on in Canada	
Dividends paid	
Dividends paid – Regular	
Dividends paid – Eligible	
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	
Balance of the general rate income pool at the end of the year	
Part I tax (base amount)	

Summary of federal carryforward/carryback information

Carryback amounts

Non-capital losses	93,185

Carryforward balances

Capital losses/L.P.P.	18,660
Unused surtax credit (Schedule 37)	6,378
Capital dividend amount	334

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	-93,185		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Surtax		N/A	N/A
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital			N/A
Capital tax payable**			N/A
Total tax payable***			
Instalments and refundable credits			
Balance due/Refund (-)			
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax loss that can be carried forward over 20 years – Schedule 510	432,693

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Fort Frances Power Corporation	5,775,246	5,775,246	5,498,939	5,498,939
Total	5,775,246	5,775,246	5,498,939	5,498,939

Québec

Corporate name	Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30)	Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18)	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total					

Ontario

Corporate name	Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514)	Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515)	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total			

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)	Net paid up capital – BC capital tax on financial institutions (FIN 689)	BC paid up capital – BC capital tax on financial institutions (FIN 689)
Total				

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2012-12-31**	**2011-12-31**	**2010-12-31**	**2009-12-31**	**2008-12-31**
Net income	-93,185	-46,885	70,147	119,095	127,124
Taxable income			70,147	119,095	127,124
Active business income			70,147	119,095	127,124
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations					
Balance due/refund (-)		-10,849	-8,780	-466	9,984

Federal taxes

Part I before surtax			7,716	10,654	9,984
Surtax					
Part I.3					
Part IV					
Part I & Surtax			7,716	10,654	9,984
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Small business deduction			11,925	20,246	21,611
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit				2,446	4,000
Abatement/other*			7,015	11,910	12,712

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

ITC refund					
Dividend refund					
Instalments					
Surtax credit					
Other*		10,849	16,496	11,120	

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2012-12-31	2011-12-31	2010-12-31	2009-12-31	2008-12-31
Net income	-93,185	-46,885	70,147		
Taxable income			70,147		
% Allocation	100.00	100.00	100.00	100.00	
Attributed taxable income			70,147		127,124
Surtax					
Income tax payable before deduction			9,113	16,673	17,797
Income tax deductions /credits			5,609	10,123	17,797
Net income tax payable			3,504	6,550	
Taxable capital			5,724,766	5,721,922	7,090,794
Capital tax payable					
Total tax payable*			3,504	6,550	
Instalments and refundable credits		10,849	20,000	17,670	33,750
Balance due/refund**		-10,849	-16,496	-11,120	-33,750

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL060

0000014

FORT FRANCES POWER CORPORATION
ATTENTION: C/O JOERG RUPPENSTEIN
320 PORTAGE AVE
FORT FRANCES ON P9A 3P9

Issue Date 15-Jul-2013

Business No. 864205893TW0001
Reference No. L1127974976

Notice of Re-Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

We have received and processed your return for the period ending 31-Dec-2011. Based on the information provided, your return has been corrected as follows:

	Previous	Revised
Total Federal Tax	$0.00	$0.00
Total Ontario Tax	$0.00	$0.00
Total Credits	($10,849.00)	($90,884.00)
Loss Carry-back	$0.00	$0.00
Total Tax Payable	$0.00	($66,601.00)
Interest		$0.00
Current Penalty		$0.00
Credits/Payments		$0.00
Total Assessment		**$0.00**

As of 15-Jul-2013, including the amount assessed above, you have an overall credit balance on your account of ($76,470.44).

If you have any questions concerning this Notice of Re-Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this re-assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the re-assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

JUL 2 3 2013

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Ontario
Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL060

FORT FRANCES POWER CORPORATION
ATTENTION: C/O JOERG RUPPENSTEIN
320 PORTAGE AVE
FORT FRANCES ON P9A 3P9

Issue Date 15-Jul-2013

Business No. 864205893TW0001
Reference No. L2101053504

Audit Notice of Re-Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

An audit re-assessment has been processed to your account as indicated below:

Audit Period: 31-Dec-2009

	Previous	Revised
Total Federal Tax	$10,654.00	$404.00
Total Ontario Tax	$6,550.00	$1,425.00
Total Credits	($28,790.00)	($33,915.00)
Loss Carry-back	$0.00	$0.00
Total Tax Payable	($466.00)	($15,841.00)
Interest		$0.00
Current Penalty		$0.00
Credits/Payments		$0.00
Total Assessment		**$0.00**

As of 15-Jul-2013, including the amount assessed above, you have an overall credit balance on your account of ($76,470.44).

If you do not agree with this Notice of Re-Assessment you have the right to serve a Notice of Objection on the minister within 180 days of the mailing date of this form. Any amounts that are outstanding as a result of this Notice of Re-Assessment are due and payable even if you have filed, or intend to file, a Notice of Objection. A Notice of Objection may be obtained through the contacts below. If your objection is successful, you will be refunded any overpayment of taxes with interest from the dates the payments were made.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

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Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL : tL059

FORT FRANCES POWER CORPORATION
ATTENTION: C/O JOERG RUPPENSTEIN
320 PORTAGE AVE
FORT FRANCES ON P9A 3P9

Issue Date 15-Jul-2013

Business No. 864205893TW0001
Reference No. L0054233152

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2010	**Return As Filed**
Total Federal Tax	$7,716.00
Total Ontario Tax	$3,504.00
Total Credits	($36,496.00)
Loss Carry-back	$0.00
Total Tax Payable	($8,780.00)
Interest	$0.00
Current Penalty	$0.00
Credits/Payments	$0.00
Total Assessment	**$0.00**

As of 15-Jul-2013, including the amount assessed above, you have an overall credit balance on your account of ($76,470.44).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

JUL 23 2013

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EXHIBIT FOUR

APPENDIX C

Fort Frances Power Corporation

Asset Retirement Obligation Position Paper

FFPC

FORT FRANCES POWER CORPORATION



SUBJECT: IFRS POSITION PAPER - ASSET RETIREMENT OBLIGATIONS

DATE: FEBRUARY 2012

BACKGROUND AND SCOPE

When an entity purchases or constructs certain assets, it can be liable for certain contractual or statutory costs to decommission or restore the asset site to certain minimum standards at the end of the asset's life. Under International Financial Reporting Standards ("IFRS"), these costs may be capitalized (generally as part of the asset's carrying value) when the entity becomes obligated to incur such costs as discussed in International Accounting Standard ("IAS") 16 *Property, Plant and Equipment* ("IAS 16").

IFRS does not have a specific standard on asset retirement obligations. Provisions are considered under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* ("IAS 37"). Asset retirement obligations (called decommissioning liabilities under IFRS) are capitalized under IAS 16. International Financial Reporting Issues Committee ("IFRIC") 1 *Changes in Existing Decommissioning, Restoration and Similar Liabilities* ("IFRIC 1") provides guidance on accounting for changes in decommissioning, restoration and similar liabilities that have previously been recognized both as part of the cost of an item of property, plant and equipment under IAS 16 and as a provision (liability) under IAS 37.

Under current accounting practice, an asset retirement obligation has not been assessed or recorded by Fort Frances Power Corporation ("FFPC" or "the Company"). The implementation of IFRS calls this practice into question and the concept of AROs must be assessed.

This paper addresses the following issues:

- Summary of Current Accounting
- Analysis
  - A. Initial Recognition / Constructive Obligations
  - B. Initial Measurement of the Obligation
  - C. First Year Adoption
- First-time Adoption of IFRS

MANAGEMENT RESPONSIBILITIES & CONCLUSIONS

BDO worked with management to outline the requirements under IFRS and help determine the implications for the Company. Management then made all applicable judgments and policy choices regarding the adoption of IFRS. Management also undertook any required quantification.

Management reviewed this memorandum in detail and accepted any and all management choices/decisions. In addition, management acknowledged their overall responsibilities for all conclusions related to compliance with CGAAP and/or IFRS.

This memorandum documents the implications related to the adoption of IFRS for the Company as of January 1, 2011, the date of transition. Management will consider the implications of transactions, which occur during the year of transition and the comparative period separately.

Summary of Current Accounting

FFPC do not currently have an accounting policy for asset retirement obligations in its financial statements.

Analysis

A. Initial Recognition / Constructive Obligations

Description of the Issue / Standard:

Initial recognition of the asset

Under IAS 16, the cost of an item of property, plant and equipment comprises "the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period". In other words, IFRS allows asset retirement obligation costs to be added to the carrying amount of the PP&E in the period in which they are incurred.

Initial recognition of the liability

IFRS addresses an entity's requirement to record liabilities through IAS 37 which states that:

A provision shall be recognized when:

- An entity has a present obligation (legal or constructive) as a result of a past event;
- It is probable that an outflow of resources embodying economic benefits will be required to settle the obligation; and
- A reliable estimate can be made of the amount of the obligation.

If these conditions are not met, no provision shall be recognized.

CGAAP requires that the asset retirement obligation be recognized and measured based on the legal obligation. IFRS uses the concept of a "constructive obligation" which is defined as an obligation that derives from an entity's actions where:

A. by an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated to other parties that it will accept certain responsibilities; and

B. as a result, the entity has created a valid expectation on the part of those other parties that it will discharge those responsibilities.

Implications and Conclusions for FFPC:

Management has assessed the above IAS 37 criteria and noted there are currently no other present obligations (legal or constructive) as a result of a past event that would require the recognition of a asset retirement obligation. Please see below for FFPC's analysis:

- **An entity has a present obligation (legal or constructive) as a result of a past event:**

This condition requires review of legal and constructive obligations. Legal obligations would be represented by those obligations outlined through contracts or legislation. Constructive obligations are those derived as a result of the entity creating an expectation through past actions or policies that said obligation will be satisfied.

In applying these to FFPC, it should be noted that the entity has not, to date, relocated distribution stations, nor have pole lines or transformers been completely removed without replacement. Therefore, there is no history to suggest that it has created a constructive obligation.

As such, it is reasonable to conclude that the entity does not have a present obligation. The communication with third parties regarding the decommissioning should be monitored and a provision raised when a legal or constructive obligation arises.

- **It is probable that an outflow of resources embodying economic benefits will be required to settle the obligation**

It is not probable that FFPC will be required to settle an obligation with an outflow of resources. It is reasonable to conclude this since, as mentioned above, the entity has yet to completely remove a single distribution station. Experience indicates that the entity would likely repair or replace equipment rather than remove and relocate its station. Given the prior, it is reasonable to conclude that this criterion is not met. However, when the obligating event occurs in the future, it will be probable that an outflow of resources will occur and a provision should be recognized.

- **A reliable estimate can be made of the amount of the obligation**

Given the industry's limited experience in removing and relocating distribution stations, it is difficult to derive an estimate of the obligation. Management could engage in a quote to determine any costs to remove and rehabilitate damaged land.

B. Initial Measurement of the Obligation

Description of the Issue / Standard:

Initial measurement of the asset

IAS 16 states that "the obligations for costs accounted for in accordance with IAS 16 are recognized and measured in accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets". Measurement of the provision is outlined below.

Initial measurement of the liability

Under IFRS, the related ARO is discounted using the best estimate of the historical risk-adjusted discount rate unadjusted for the effect of an entity's credit standing. IAS 37 requires that the discount rate be a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

The best estimate of the expenditure required to settle the present obligation is the amount that an entity would rationally pay to settle the obligation at the end of the reporting period, or to transfer it to a third party at that time. The liability reflects the condition of the assets. Therefore, provisions for closure and environmental costs exclude any additional obligations that are expected to arise from future disturbances. The costs also exclude the impact of any expected proceeds on sale or disposal of scrap materials.

If the provision involves a large number of items, the 'best estimate' is determined by taking into account all possible outcomes and using probabilities to weight those outcomes.

The costs include not only external expenditure but also internal costs essential to the closure.

Factors to consider when determining the 'best estimate' are:

- expected inflation;
- advances in technology;

- productivity improvements; and
- the particular circumstances faced by the operation.

Management must only take changes in technology or in regulation/legislation into account if there is demonstrable evidence that those changes will occur.

If the settlement of the obligation occurs over a period of time, the estimate of future costs is discounted using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the liability. It is not acceptable to use the incremental method, whereby the entity accrues for the total future expected closure and environmental costs by gradually increasing the provision over the life of the asset.

Implications and Conclusions for FFPC:

Management should be aware of the initial measure of ARO's under IFRS for future considerations.

C. Changes in the Obligations

Description of the Issue / Standard:

Under IFRS, subsequent to the initial recognition of the asset retirement obligation, the provision is reviewed at each balance sheet date and adjusted to reflect the current best estimate, which may include adjustments to the discount rate used to measure the provision. The entire obligation is remeasured using the current discount rate. Changes resulting from revisions in the timing or amount of estimated cash flows should be recognized as an increase or decrease in the carrying amount of the ARO and the associated capitalized asset.

IFRIC 1 provides guidance on accounting for changes in a decommissioning, restoration or similar liability that have been previously recognized as part of the cost of an item of property, plant and equipment and as a liability. IFRIC 1 requires that changes in such liabilities due to the estimated timing or amount of the outflow of resources required to settle the obligation, or a change in the discount rate, are accounted for based on whether the underlying asset is carried at cost or a revaluation amount. If an asset is carried at cost, the changes to the decommissioning liability are generally added to or deducted from the asset cost. If an asset is carried at a revaluation amount, the change in the liability alters the revaluation surplus or deficit previously recognized on that asset.

CGAAP only requires entities to recognize period-to-period changes in an ARO resulting from the passage of time and revisions to either the timing or amount of the original undiscounted cash flows estimate. Under IFRS, subsequent to the initial recognition of the asset retirement obligation, the provision is reviewed at each balance sheet date and adjusted to reflect the current best estimate, which may include adjustments to the discount rate used to measure the provision. Therefore under IFRS only, the ARO is likely to change due to fluctuations in the discount rate.

Implications and Conclusions for FFPC:

Management should be aware of the accounting treatment for changes in asset retirement obligations for possible future considerations.

D. Classification of Accretion Expense

Description of the Issue / Standard:

Under IFRS, the accretion expense is recorded as part of finance costs, on the statement of comprehensive income, rather than as an element of operating costs under CGAAP.

Implications and Conclusions for FFPC:

FFPC must be aware of the reclassification of accretion expense under IFRS for future consideration. Upon transition to IFRS, accretion expenses will be recorded as part of finance costs on the statement of comprehensive income.

First Time Adoption of IFRS

Description of the Issue / Standard

Upon adoption, no transitional adjustments are required to the extent that Management has arrived to a conclusion consistent with Canadian GAAP.

Implications and Conclusion for FFPC:

FFPC does not have any current asset retirement obligations under IFRS. This is not likely to change in the near future; however, it should be continuously monitored by management.

EXHIBIT FOUR

A P P E N D I X D

Fort Frances Power Corporation

PILs Model- PDF Version



Income Tax/PILs Workform for 2014 Filers

Version **2.0**

Utility Name	Fort Frances Power Corporation
Assigned EB Number	EB-2013-0130
Name and Title	Joerg Ruppenstein, President and CEO
Phone Number	807-274-9291
Email Address	ffpc@fort-frances.com
Date	20-Dec-13
Last COS Re-based Year	

Note: Drop-down lists are shaded blue; Input cells are shaded green.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your rate application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy o the data and the results.

Algoma Power Inc.
Atikokan Hydro Inc.
Attawapiskat Power Corp.
Bluewater Power Distribution Corporation
Brant County Power Inc.
Brantford Power Inc.
Burlington Hydro Inc.
Cambridge and North Dumfries Hydro Inc.
Canadian Niagara Power Inc. - Eastern Ontario Power
Canadian Niagara Power Inc. - Fort Erie
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.
Centre Wellington Hydro Ltd.
Clinton Power Corporation
COLLUS Power Corporation
Cooperative Hydro Embrun Inc.
E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.
Entegrus Powerlines Inc. - Chatham-Kent
Entegrus Powerlines Inc. - Dutton
Entegrus Powerlines Inc. - Newbury
Entegrus Powerlines Inc. - Strathroy, Mounth Brydges & Parkhill
ENWIN Utilities Ltd.
Erie Thames Powerlines Corporation
Espanola Regional Hydro Distribution Corporation
Essex Powerlines Corporation
Festival Hydro Inc.
Festival Hydro Inc. - Hensall
Fort Albany Power Corporation
Fort Frances Power Corporation
Greater Sudbury Hydro Inc.
Grimsby Power Inc.
Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.

Hearst Power Distribution Company Limited
Horizon Utilities Corporation
Hydro 2000 Inc.
Hydro Hawkesbury Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc.
Hydro Ottawa Limited
Innisfil Hydro Distribution Systems Limited
Kashechewan Power Corporation
Kenora Hydro Electric Corporation Ltd.
Kingston Hydro Corporation
Kitchener-Wilmot Hydro Inc.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
London Hydro Inc.
Midland Power Utility Corporation
Milton Hydro Distribution inc.
Newmarket - Tay Power Distribution Ltd. - Newmarket
Newmarket - Tay Power Distribution Ltd. - Tay
Niagara Peninsula Energy Inc. - Niagara Falls
Niagara Peninsula Energy Inc. - Peninsula West
Niagara-on-the-Lake Hydro Inc.
Norfolk Power Distribution Inc.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Oakville Hydro Electricity Distribution Inc.
Orangeville Hydro Limited
Orillia Power Distribution Corporation
Oshawa PUC Networks Inc.
Ottawa River Power Corporation
Parry Sound Power Corporation
Peterborough Distribution Incorporated
PowerStream Inc. - Barrie
PowerStream Inc. - South
PUC Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.
Sioux Lookout Hydro Inc.
St. Thomas Energy Inc.
Thunder Bay Hydro Electricity Distribution Inc.
Tillsonburg Hydro Inc.

Toronto Hydro-Electric System Limited
Veridian Connections Inc.
Veridian Connections Inc. - Gravenhurst
Wasaga Distribution Inc.
Waterloo North Hydro Inc.
Welland Hydro-Electric System Corp.
Wellington North Power Inc.
West Coast Huron Energy Inc.
West Perth Power Inc.
Westario Power Inc.
Whitby Hydro Electric Corporation
Woodstock Hydro Services Inc.



1. Info
A. Data Input Sheet
B. Tax Rates & Exemptions
C. Sch 8 Hist
D. Schedule 10 CEC Hist
E. Sch 13 Tax Reserves Hist
F. Sch 7-1 Loss Cfwd Hist
G. Adj. Taxable Income Historic
H. PILs,Tax Provision Historic
I. Schedule 8 CCA Bridge Year
J. Schedule 10 CEC Bridge Year



K. Sch 13 Tax Reserves Bridge
L. Sch 7-1 Loss Cfwd Bridge
M. Adj. Taxable Income Bridge
N. PILs,Tax Provision Bridge
O. Schedule 8 CCA Test Year
P. Schedule 10 CEC Test Year
Q Sch 13 Tax Reserve Test Year
R. Sch 7-1 Loss Cfwd
S. Taxable Income Test Year
T. PILs,Tax Provision



Income Tax/PILs Workform for 2014 Filers

Rate Base			**$**	**4,856,564**	

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	$	194,263	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	2,719,676	*X = S * U*
Deemed Equity %	40.00%	V	$	1,942,626	*Y = S * V*
Short Term Interest Rate	2.07%	Z	$	4,021	*AC = W * Z*
Long Term Interest	4.12%	AA	$	112,051	*AD = X * AA*
Return on Equity (Regulatory Income)	8.98%	AB	**$**	**174,448**	*AE = Y * AB*
Return on Rate Base			**$**	**290,520**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	**Bridge**	**Test Year**
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	Yes	Yes
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	Yes	Yes	Yes
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	No	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No



Income Tax/PILs
Workform for 2014 Filers

Tax Rates **Federal & Provincial** **As of June 20, 2012**	**Effective** ################	**Effective** ################	**Effective** ################	**Effective** ################
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%



Income Tax/PILs Workform for 2014 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	2,999,877		2,999,877
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	257,676		257,676
2	Distribution System - pre 1988			0
8	General Office/Stores Equip	355,227		355,227
10	Computer Hardware/ Vehicles	451		451
10.1	Certain Automobiles	123,175		123,175
12	Computer Software	380		380
13 $_1$	Lease # 1	37,777		37,777
13 $_2$	Lease #2			0
13 $_3$	Lease # 3			0
13 $_4$	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	294		294
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	894,504		894,504
50	Data Network Infrastructure Equipment - post Mar 2007	2,410		2,410
52	Computer Hardware and system software			0
95	CWIP			0
				0
				0
				0
				0
	Note: FFPC Used 2012 As 'Historical Year' for continuity purposes.			0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	4,671,771	0	4,671,771



Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital

Additions

Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				0

Deductions

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0

Cumulative Eligible Capital Balance				0
Current Year Deduction		0	x 7% =	0
Cumulative Eligible Capital - Closing Balance				0



Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**0**	**0**	**0**



Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic	0		0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic	18,660		18,660



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	-313,913		-313,913
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	564,032		564,032
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	8,367		8,367
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Provision for Income Taxes-current- Line 101		-22,453		-22,453

Provision for Income Taxes-deferred				0
Unrealized Loss on Investments		16,173		16,173
Increase in Vested Sick Leave Liability		1,431		1,431
2012 Ontario Apprenticeship Tax Credit		4,906		4,906
				0
				0
				0
				0
				0
Total Additions		**572,456**	**0**	**572,456**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	351,728		351,728
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Provision -Recovery of Current Income Taxes				0
				0
				0
				0
				0
				0
				0
Total Deductions		**351,728**	**0**	**351,728**
Net Income for Tax Purposes		**-93,185**	**0**	**-93,185**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**-93,185**	**0**	**-93,185**



PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

						Wires Only	
Regulatory Taxable Income						-$ 93,185	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	0.00%	**B**	$ -	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction (negative)	0.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ -	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			0.00%	**K = J / A**		
	Federal tax rate			0.00%	**L**		
	Combined tax rate					0.00%	**M = K + L**
Total Income Taxes						**$ -**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits						-$ 7,077	**P**
Total Tax Credits						**-$ 7,077**	**Q = O + P**
Corporate PILs/Income Tax Provision for Historic Year						**$ 7,077**	**R = N - Q**



Income Tax/PILs
Workform for 2014 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 2,999,877			$ 2,999,877	$ -	$ 2,999,877	4%	$ 119,995	$ 2,879,882
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 257,676			$ 257,676	$ -	$ 257,676	4%	$ 10,307	$ 247,369
2	Distribution System - pre 1988				$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 355,227	$ 16,900		$ 372,127	$ 8,450	$ 363,677	20%	$ 72,735	$ 299,392
10	Computer Hardware/ Vehicles	$ 451	$ 125,900	-$ 107,038	$ 19,313	$ 9,431	$ 9,882	30%	$ 2,965	$ 16,348
10.1	Certain Automobiles	$ 123,175			$ 123,175	$ -	$ 123,175	30%	$ 36,953	$ 86,223
12	Computer Software	$ 380			$ 380	$ -	$ 380	100%	$ 380	$ -
13 1	Lease # 1	$ 37,777			$ 37,777	$ -	$ 37,777	4%	$ 1,511	$ 36,266
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 294			$ 294	$ -	$ 294	45%	$ 132	$ 162
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 894,504	$ 192,160		$ 1,086,664	$ 96,080	$ 990,584	8%	$ 79,247	$ 1,007,417
50	Data Network Infrastructure Equipment - post Mar 2007	$ 2,410	$ 27,500		$ 29,910	$ 13,750	$ 16,160	55%	$ 8,888	$ 21,022
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 4,671,771	$ 362,460	-$ 107,038	$ 4,927,193	$ 127,711	$ 4,799,482		$ 333,113	$ 4,594,080



Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**0**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**0**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**



Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**



Income Tax/PILs Workform for 2014 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	Total
Actual Historic	18,660
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	18,660
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	18,660



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	A	382,055

Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	178,000
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	5,000
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
2013 Ontario Apprenticeship Tax Credit		7,000
Total Additions		**190,000**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	333,113
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**333,113**
Net Income for Tax Purposes		**238,942**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**238,942**



PILS Tax Provision - Bridge Year

						Wires Only	
Regulatory Taxable Income						$ 238,942	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$ 10,752	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-7.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ 10,752	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			4.50%	**K = J / A**		
	Federal tax rate			11.00%	**L**		
	Combined tax rate					15.50%	**M = K + L**
Total Income Taxes						**$ 37,036**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits						$ 7,000	**P**
Total Tax Credits						**$ 7,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ 30,036**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.



Income Tax/PILs
Workform for 2014 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 2,879,882			$ 2,879,882	$ -	$ 2,879,882	4%	$ 115,195	$ 2,764,687
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 247,369			$ 247,369	$ -	$ 247,369	4%	$ 9,895	$ 237,474
2	Distribution System - pre 1988	$ -			$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 299,392	16,500		$ 315,892	$ 8,250	$ 307,642	20%	$ 61,528	$ 254,363
10	Computer Hardware/ Vehicles	$ 16,348	45,500	-21,142	$ 40,706	$ 12,179	$ 28,527	30%	$ 8,558	$ 32,148
10.1	Certain Automobiles	$ 86,223			$ 86,223	$ -	$ 86,223	30%	$ 25,867	$ 60,356
12	Computer Software	$ -			$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1	$ 36,266			$ 36,266	$ -	$ 36,266	4%	$ 1,451	$ 34,815
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than E	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 162			$ 162	$ -	$ 162	45%	$ 73	$ 89
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 1,007,417	647,768		$ 1,655,185	$ 323,884	$ 1,331,301	8%	$ 106,504	$ 1,548,681
50	Data Network Infrastructure Equipment - post Mar 2007	$ 21,022	2,000		$ 23,022	$ 1,000	$ 22,022	55%	$ 12,112	$ 10,910
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 4,594,080	$ 711,768	-$ 21,142	$ 5,284,706	$ 345,313	$ 4,939,393		$ 341,183	$ 4,943,523



Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital

					0
Additions					
Cost of Eligible Capital Property Acquired during Test Year		0			
Other Adjustments		0			
	Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002		0	**x 1/2 =**	0	
				0	**0**
Amount transferred on amalgamation or wind-up of subsidiary		0			**0**
	Subtotal				**0**
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year		0			
Other Adjustments		0			
	Subtotal	0	**x 3/4 =**		**0**

Cumulative Eligible Capital Balance			**0**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")	**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance			**0**



Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**



Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	18,660		18,660
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	18,660	0	18,660
Amount to be used in Test Year			0
Balance available for use post Test Year	18,660	0	18,660



Income Tax/PILs Workform for 2014 Filers

Taxable Income - Test Year

		Test Year Taxable Income
Net Income Before Taxes		174,448

	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	179,000
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	5,000
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**184,000**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	341,183
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	0
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
2013 Ontario Apprenticeship Tax Credit		7,000
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**348,183**
NET INCOME FOR TAX PURPOSES		**10,265**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**10,265**



PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 10,265	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$ 462	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-7.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ 462	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			4.50%	**K = J / A**		
	Federal tax rate			11.00%	**L**		
	Combined tax rate					15.50%	**M = K + L**
Total Income Taxes						**$ 1,591**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 1,591**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				84.50%	**S = 1 - M**	**$ 292**	**T = R / S - R**
Income Tax (grossed-up)						**$ 1,883**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

FFPC
FORT FRANCES POWER CORPORATION

Filing Number: EB-2013-0130
Filed: December 20, 2013

EXHIBIT FIVE

COST OF CAPITAL AND CAPITAL STRUCTURE

Exhibit	Tab	Schedule	Appendix	Contents
5 – Cost of Capital and Rate of Return				
	1	1		Overview
		2		Capital Structure Deemed & Actual

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2014 test year. FFPC understands that Distributors are to use the most recent parameters as a placeholder, subject to an update when new parameters are available prior to the issuance of the Board's decision for this rate application. FFPC was notified of the new cost of capital parameters to be used in 2014 Cost of Service Application from the November 25, 2013 Board notification as shown below:

Cost of Capital Parameter	**Value for 2014 Cost of Service Applications for rate changes in 2014**
ROE	9.36%
Deemed LT Debt rate	4.88%
Deemed ST Debt rate	2.11

FFPC has elected to use the following:

Cost of Capital Parameter	**Value for 2014 Cost of Service Applications for rate changes in 2014**
ROE	0.00%
Deemed LT Debt rate	4.88%
Deemed ST Debt rate	2.11

FFPC has elected to seek a zero rate of return for their Return on Equity to maintain the 'not-for-profit' structure.

CAPITAL STRUCTURE:

FFPC is a not-for-profit corporation has no actual debt and operates with a zero rate of return.

In the OEB, Filing Requirements for Electricity Distribution Rate Applications, dated July 17, 2013, Chapter 2, Cost of Service, 2.8.3., states:

> "…the Board has determined that applicants which are not-for-profit corporations may apply using the Board's deemed capital structure, cost of capital and working capital allowance to the extent that the excess revenue is to be used for the purpose of meeting the applicant's need to build up or accumulate appropriate operating and capital reserves."

FFPC has an accumulated deficit of $513,338 as stated in Shareholder Equity portion of FFPC's audited Financial Statements for the year ended December 31, 2012. With the approval of this application, FFPC is seeking to address this deficiency by rebuilding operating and capital reserves to support the ongoing business of FFPC. FFPC, when in an excess revenue position, allocates all funds to build up operating and capital reserves.

FFPC's deemed capital structure as approved in the last Cost of Service Application in 2006 (EB-2005-0366) included a 50% Equity, 50% Debt Ratio, 6.25% deemed debt rate based on the size of the Corporation, which is under $10 Million. In the 2006 EDR application, the following was noted:

> "The Board notes that Fort Frances Power is foregoing the allowed return on equity. The Board accepts Fort Frances Power's concern about its compliance with all clauses in the historical agreement and therefore its selection is 0% rate of return on equity."
>
> *Fort Frances Power Corporation, 2006 EDR EB-2005-0366, Decision and Order, pg 3*

FFPC was granted at Cost of Capital Return on Rate base of 2.82%, resulting in a revenue requirement adjustment of $136,819.

FFPC has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 4.88%, 4% Short Term Debt with a return of 2.11%, and 40% Equity with a return of 0.0% as directed in the Cost of Capital Parameters Updates for 2014 Cost of Service Applications letter of November 25, 2014.

RETURN ON EQUITY

FFPC is requesting a return on equity ("ROE") for the 2014 Test year of 0.0%. FFPC has chosen a zero rate of return to preserve its benefits of the historic 1905 agreement, as explained below.

FFPC is unique as its customers, precisely the residents of the Town of Fort Frances, are beneficiaries of a historic 1905 Agreement entered into between the Town and the local pulp and paper mill. The 1905 Agreement obligates the mill owner, or more precisely today, the owner of the generation assets on the Rainy River (currently H2O Power LP ("H2O")), to provide to the Town of Fort Frances, in perpetuity, 4,000 horsepower (2.984 Megawatts) at $14 per horsepower per annum (0.21416 cents per kilowatt hour) "for municipal purposes and for public utilities" [*Fort Frances v Boise Cascade Canada Ltd*., [1983] 1 SCR 171 at 184].

FFPC fulfills the role of steward of the 1905 agreement on behalf of the residents of the Town of Fort Frances. Further, given the value of the 1905 Agreement to the residents of the Town of Fort Frances, and the corresponding cost to the owner of the generation assets on the Rainy River, the 1905 Agreement is under constant attack from the owner of the generation assets. Finally, the existence of the 1905 Agreement and the manner in which it reduces the price for power paid by the residents of the Town of Fort Frances relative to other ratepayers in the

Province often requires that FFPC be given unique and specific treatment by government policy, regulation and legislation so as to preserve its benefits.

FFPC has elected to operate within a 'not-for-profit' structure to ensure the safe guarding of the agreement on behalf of its customer base within the Town of Fort Frances. Further details regarding the 1905 agreement can be found in the opening section of Exhibit 1.

COST OF DEBT

FFPC has no debt instruments within its actual capital structure. In the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 (EB-2009-0084) page 54 states:

> *"The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt."*

As a result, FFPC has assumed the deemed debt ratios as stated above for the purposes of setting distribution rates in this application.

CAPITAL STRUCTURE AND COST OF CAPITAL

FFPC has completed the required Capital Structure and Cost of Capital tables, as shown in the tables below.

Last Board Approved Year: 2006

Year: 2006
Last Board Approved Year

Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
Debt					
Long-term Debt	50.00%		$2,903,696		$ -
Short-term Debt		(1)	$ -	0.00%	$ -
Total Debt	50.0%		$2,903,696	0.00%	$ -
Equity					
Common Equity	50.00%		$2,903,696	6.25%	$181,481
Preferred Shares			$ -		$ -
Total Equity	50.0%		$2,903,696	6.25%	$181,481
Total	100.0%		$5,807,391	3.13%	$181,481

Year 2014:

Year: 2014 TEST YEAR

Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
Debt					
Long-term Debt	56.00%		$2,719,687	4.88%	$132,720
Short-term Debt	4.00%	(1)	$194,263	2.11%	$4,099
Total Debt	60.0%		$2,913,950	4.70%	$136,819
Equity					
Common Equity	40.00%		$1,942,634	0.00%	$ -
Preferred Shares			$ -		$ -
Total Equity	40.0%		$1,942,634	0.00%	$ -
Total	100.0%		$4,856,584	2.82%	$136,819

FFPC
FORT FRANCES POWER CORPORATION

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EXHIBIT SIX

REVENUE DEFICIENCY/ SUFFICIENCY

Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency or Surplus				
	1	1		Revenue Deficiency – Overview
	1	2		Cost Drivers for Revenue Deficiency
			A	Revenue Requirement Work form-PDF

REVENUE DEFICIENCY - OVERVIEW:

Fort Frances Power Corporation's (FFPC) net revenue deficiency is $459,007 and there is no adjustment for PILs. This deficiency is calculated as the difference between the 2014 Test Year Revenue Requirement of $1,989,765 and the Forecast 2014 Test Year Revenue, based on the 2013 approved rates, at $1,427,725. Table 6-1 on the following page provides the revenue deficiency calculations.

Revenue Requirement:

FFPC's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILs
- Deemed Interest & Return on Equity

FFPC's revenue requirement is primarily received through electricity distribution rates and is offset by revenue from OEB-approved specific service charges, late payment charges, and other miscellaneous revenues.

Table 6.1: Revenue Deficiency

Revenue Deficiency Determination	At Current Approved Rates		At Current Approved Rates
Revenue			
Revenue Deficiency from Below			$ 459,007
Distribution Revenue	$ 1,427,725		$ 1,427,725
Other Operating Revenue Offsets - net	$ 103,033		$ 103,033
Total Revenue	**$ 1,530,758**		**$ 1,989,765**
Costs and Expenses			
OM & A Expenses	$ 1,644,650		$ 1,644,650
Depreciation and Amortization	$ 197,074		$ 197,074
Property Tax	$ 13,000		$ 13,000
Deemed Interest Expense	$ 135,041		$ 135,041
Total Cost and Expenses	$ 1,989,766		$ 1,989,765
Income Taxes			
Utility Income Before Income Taxes	$ (459,007)		$ 0
Tax Adjustments to Accounting - Income per 2013 PILs model	$ (112,286)		$ (112,286)
Taxable Income	$ (571,293)		$ (112,286)
Income Tax Rate	0.00%		0.00%
Income Tax on Taxable Income			
Income Tax Credits			
Utility Net Income			
Return on Rate Base			
Utility Rate Base	$ 4,793,453		$ 4,793,453
Deemed Equity Portion of Rate Base	$ 1,917,381		$ 1,917,381
Income/(Equity Portion of Rate Base)	-19.90%		0.00%
Target Return - Equity on Rate Base			0.00%
Deficiency/Sufficiency in Return on Equity	-19.90%		0.00%
Indicated Rate of Return	-5.14%		2.82%
Requested Rate of Return on Rate Base	2.82%		2.82%
Deficiency/Sufficiency in Rate of Return	-7.96%		0.00%
Target Return on Equity	**$ -**		**$ -**
Revenue Deficiency/(Sufficiency)	**$ 459,007**		**$ 0**
Gross Revenue Deficiency/(Sufficiency)	**$ 459,007**	**(1)**	

COST DRIVERS ON REVENUE DEFICIENCY

FFPC notes that there are two main contributors to the revenue deficiency of $459,007 for the 2014 Test Year:

- The first main contributor to the revenue deficiency is the associated cost increases since FFPC's last CoS Application for rates approved for 2006. The eight year span covering this CoS period is twice the normal rebasing period and the inflationary increases on materials, services and other non-labour costs are estimated to 13%. The Ontario 2006 Consumer Price Index (CPI) was 108.8, compared to the 2012 of 121.8 CPI, the difference being 13.0.

  (Source: http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ150a-eng.html)

- The second relates to payroll and benefit cost increases since 2006. FFPC intends to hire in 2014 for one additional staff member, a technical support person, to assist with increased work load due to Green Energy initiatives and customer initiatives. FFPC's customer survey stated that FFPC customer focus requested more residential based energy savings initiatives and support.

The following table outlines the costs associated with the three contributors. In total, they exceed the revenue deficiency.

• Increases in OM&A due to inflation on base operating costs 2006 OM&A- ($1,125,164 – $565,749) *13%=$72,723 *(Change in Ontario CPI from 2006-2012)*	$72,723
• 2014 Increase in payroll and benefits versus 2006 Actual (Exhibit 4, Tab 2, Schedule 7, Compensation Level Table; $936,734-$565,749)	$370,985
Total	$443,708

APPENDIX A

Fort Frances Power Corporation

Revenue Requirement Workform

PDF Version

1



Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$459,007		$426,999		$1,854,724
2	Distribution Revenue	$1,427,725	$1,427,725	$1,427,725	$1,459,733	$ -	($1,854,724)
3	Other Operating Revenue Offsets - net	$103,033	$103,033	$ -	$ -	$ -	$ -
4	**Total Revenue**	$1,530,758	$1,989,765	$1,427,725	$1,886,732	$ -	$ -
5	Operating Expenses	$1,854,724	$1,854,724	$1,854,724	$1,854,724	$1,854,724	$1,854,724
6	Deemed Interest Expense	$135,041	$135,041	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$1,989,765	$1,989,765	$1,854,724	$1,854,724	$1,854,724	$1,854,724
9	**Utility Income Before Income Taxes**	($459,007)	($0)	($426,999)	$32,008	($1,854,724)	($1,854,724)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($160,094)	($160,094)	($160,094)	($160,094)	$ -	$ -
11	**Taxable Income**	($619,101)	($160,094)	($587,093)	($128,086)	($1,854,724)	($1,854,724)
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	($459,007)	($0)	($426,999)	($1,854,724)	($1,854,724)	($1,854,724)
16	**Utility Rate Base**	$4,793,453	$4,793,453	$4,793,453	$4,793,453	$4,793,453	$4,793,453
17	Deemed Equity Portion of Rate Base	$1,917,381	$1,917,381	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	-23.94%	0.00%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-23.94%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	-6.76%	2.82%	-8.91%	0.00%	-38.69%	0.00%
22	Requested Rate of Return on Rate Base	2.82%	2.82%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-9.58%	0.00%	-8.91%	0.00%	-38.69%	0.00%
24	Target Return on Equity	$ -	$ -	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$459,007	($0)	$426,999	$ -	$1,854,724	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$459,007 **(1)**		$426,999 **(1)**		$1,854,724 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

FFPC
FORT FRANCES POWER CORPORATION

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EXHIBIT SEVEN

COST ALLOCATION

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1	1		Cost Allocation Overview
	1	2		Summary of Results and Proposed Changes
			7-A	2014 Updated Cost Allocation Study

COST ALLOCATION OVERVIEW:

Introduction:

On September 29, 2006, the Board issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. FFPC prepared a cost allocation information filing consistent with FFPC's understanding of the Directions, the Guidelines, the Model and the Instructions. FFPC submitted the cost allocation informational filing with the Board on September 7, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

FFPC's last Cost of Service application was completed as the 2006 EDR Rate Application, EB-2005-0366 and, because of this, the current rates have not been adjusted to reflect the result of a cost allocation study.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released the new Cost Allocation model revised for the work completed by the Working Group and instructed 2012 Cost of Service filers to use the revised model in their applications. This model has been subsequently updated by the Board with some minor revision on an annual basis. The 2014 version of the cost allocation model has been used by FFPC in this application.

In the March 31st Board Report, the Board stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

FFPC has completed a 2014 cost allocation study to reflect 2014 test year costs, customer numbers and demand values. The 2014 demand values are based on the weather normalized load forecast used to design rates. FFPC has developed weighting factors as outlined below based on discussions with staff experienced in the subject area.

Services (Account 1855)

The analysis for the Services weighting factor included a review of FFPC's existing policy in regard to the installation and cost recovery for services. In most cases, FFPC will supply to residential and General Service<50kW customers overhead triplex and quadriplex. For underground services, FFPC requests that secondary underground is supplied and installed by the customer. FFPC has an average of less than two new housing connections per year and the gross asset value for services is low due to the low cost at original installation date.

General Service>50 kW customers are required to supply all secondary cable, overhead or underground as a requirement of a new service connection. The customer is responsible for subsequent maintenance and repair of all conductors, therefore resulting in a zero cost burden.

FFPC is following the suggested methodology on the Cost Allocation instruction sheet where Residential was given a weighting factor of '1'.

Table 7.1: Service Weighting Factors

Rate Class	FFPC Factor	OEB Default Factor
Residential	1.0	1
General Service <50 kW	2.7	2
General Service >50 kW	0.0	10
Street Lighting	1.8	1
Unmetered Scattered Load	0.6	1

FFPC determined by a review of capital replacement cost as detailed in FFPC's Asset Management Policy the following weighting for services.

By determining the rate class specific percentage of replacement cost, FFPC allocated the following Gross Fixed Assets for Services in a 'Cost per Customer' burden. The higher cost for General Service <50 kW is due to the larger service wire due to larger service size or three phase service. General Service >50 kW are not included in this cost pool as the service costs are borne by the customer in perpetuity.

Table 7.2: Weighting for Services

FFPC- Direct Allocation by Rate Class-Percentage of Replacement Cost - Gross Fixed Assets						
Rate Class Base Measures	Total	Residential	GS<50 kW	GS>50 kW	Street Light	USL
# of Customers	**3,764**	3,290	405	47	16	6
% of Customers	**100%**	87.4%	10.8%	1.2%	0.4%	0.2%
Consumption	**78,161,020**	37,751,518	13,617,679	26,376,324	366,947	48,552
% of Consumption	**100%**	48.3%	17.4%	33.7%	0.5%	0.1%
Services- 1855	**$ 11,197**	**$ 8,351**	**$ 2,762**	**$ -**	**$ 74**	**$ 10**
Cost Percentage	**100%**	74.6%	24.7%	0.0%	0.7%	0.09%
Cost per Customer	**$2.97**	**$2.54**	**$6.82**	**$0.00**	**$4.65**	**$1.64**
Weighting		**1.0**	**2.7**	**0.0**	**1.8**	**0.6**

Table 7.3: Billing and Collection (Accounts 5315 – 5340, except 5335)

Billing and Collecting Weighting Factors		
Rate Class	**FFPC Factor**	**OEB Default Factor**
Residential	**1.0**	**1**
General Service <50 kW	**1.2**	**2**
General Service >50 kW	**4.4**	**7**
Street Lighting	8.0	**1**
Unmetered Scattered Load	1.0	**5**

FFPC developed the weighting factors for Billing and Collecting as shown in the table below:

Table 7.4: Billing and Collecting Cost Determinants

Billing and Collection-Annual Cost Determinants		Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load	Total
Postage	0.63	$ 32,511	$ 3,484	$ 391	$ 8	$ 50	$ 36,444
Customer Billing-Cost Per Rate Class		$ 38,656	$ 6,332	$ 2,368	$ 225	$ 38	$ 47,619
GS ST Billing more detailed/prone to rebill							
Thunder Bay Billing Charges		$ 57,711	$ 8,311	$ 8,391	$ 290	$ 298	$ 75,000
CIS services/billing support							
Account changes and updates.		$ 42,857	$ 2,650	$ 2,112	$ -	$ -	$ 47,619
Mill bankruptcy/changes increase GS work							
Collecting Cash Payments		$ 20,000	$ 3,850	$ 600	$ 20	$ 30	$ 24,500
Large walk-in RES payments & part payments							
Collecting Overdue Bad Debt		$ 17,150	$ 7,150	$ 200	$ -	$ -	$ 24,500
GS<50 payment plan management burden							
		$ 208,885	**$ 31,778**	**$ 14,061**	**$ 543**	**$ 415**	**$ 255,682**
Collecting Overdue Accounts		$ 14,860	$ 1,035	$ 30	$ -	$ -	$ 15,925
	Total Costs	**$ 223,745**	**$ 32,813**	**$ 14,091**	**$ 543**	**$ 415**	**$ 271,607**
	Cost Per Customer	**$ 67.64**	**$ 78.31**	**$ 299.81**	**$ 543.32**	**$ 69.20**	
		1.0	**1.2**	**4.4**	**8.0**	**1.0**	**WEIGHTING**

Table 7.5: Meter Capital (Cost Allocation Model, Sheet I7.1)

Table Meter Capital Installation Costs	
Rate Class	**Cost Per Meter**
Residential	**$ 185**
General Service <50 kW	**$ 315**
General Service >50 kW	**$ 618**
Street Lighting	na
Unmetered Scattered Load	na

The meter capital installation costs are determined by the net capital investment for Smart meters installed in all metered rate classes in the years 2009 and 2010, and the associated equipment (potential transformers, current transformers, etc.) plus the cost of installation.

Table 7.6: Meter Reading (Sheet I7.2)

Table Meter Reading Weighting Factors	
Rate Class	**FFPC Factor**
Residential	**1.0**
General Service <50 kW	**1.0**
General Service >50 kW	**14.5**
Street Lighting	na
Unmetered Scattered Load	na

FFPC has converted all meter reading to Smart Meter technology with the exception of the demand reading set-back for the GS>50kW rate class. Currently, a contracted meter reader performs an on-site meter reading once a month. FFPC is working with Thunder Bay staff to implement demand meter set-back via the Smart Meter service provider when possible.

SUMMARY OF RESULTS AND PROPOSED CHANGES:

The data used in the updated cost allocation study is consistent with FFPC's cost data that supports the proposed 2014 revenue requirement outlined in this Application. Consistent with the Guidelines, FFPC's assets were broken out into primary and secondary distribution functions using current information on the distribution system. The breakout of assets, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to FFPC, its engineering records, and its customer and financial information systems. The cost allocation study has been included in Appendix 7-A.

Depreciation and accumulated depreciation USoA are consistent with the information provided in the 2014 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2014 customer forecast outlined in Exhibit 3. For the Street Lighting class, the number of connections reflects the actual number of connections of the street light system to FFPC's distribution system. FFPC's Street Lighting rate class is connected through a 'piloted' system, by which a relay is powered through a photocell that connects a large series of lights.

The load profiles for all rate class are the same as those used in the original information filing but have been scaled to match the 2014 load forecast. FFPC's Street Lighting class load profile was revised to reflect the customer initiated LED retrofit that reduced load to one-third of original load, as detailed in Exhibit 3. The following table outlines the scaling factors used by rate class.

Table 7.7: **Load Profile Scaling Percentages**

Load Profile Scaling Percentages			
Rate Class	**2004 Weather Normal Values used in Original Filing (kWh)**	**2014 Weather Normal Values (kWh)**	**Scaling Factor**
Residential	38,423,702	37,751,518	98.3%
General Service <50 kW	21,496,720	13,617,679	63.3%
General Service >50 kW	20,470,323	26,376,324	128.9%
Street Lighting	1,329,072	366,947	27.6%
Unmetered Scattered Load	192,228	48,552	25.3%
Total	**81,912,045**	**78,161,019**	**95.4%**

The allocated cost by rate class from the original cost allocation study and the 2014 updated study are provided in the following table:

Table 7.8: Original vs. Updated Cost Allocated Studies

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	%
Residential	$ 930,775	62.03%	$ 1,366,130	68.66%
GS < 50 kW	$ 297,235	19.81%	$ 376,450	18.92%
GS > 50kW -4999 kW	$ 241,620	16.10%	$ 218,356	10.97%
Street Lighting	$ 28,609	1.91%	$ 26,060	1.31%
Unmetered Scattered Load (USL)	$ 2,372	0.16%	$ 2,770	0.14%
Total	$ 1,500,611	100.00%	$ 1,989,766	100.00%

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater

than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the March 31, 2011 Report of the Board on Cost Allocation released in relation to EB-2010-0219, the Board established what it considered to be the appropriate ranges of revenue-to-cost ratios. Those are summarized in Table 7-8 below. In addition, Table 7-8 provides the revenue-to-cost ratios from FFPC's approved 2006 approved rate application (EB-2005-0366); the updated 2014 cost allocation study and the proposed 2014 ratios.

Table 7.9: Rebalancing Revenue to Cost Ratios

Class	Previous Ratios Most Recent Year: 2006	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	91.60	83.46	94.68	85 - 115
GS < 50 kW	105.79	86.53	93.94	80 - 120
GS > 50kW -4999 kW	126.30	226.45	177.38	80 - 120
Street Lighting	89.56	95.45	98.97	70 - 120
Unmetered Scattered Load (USL)	117.05	119.32	98.18	80 - 120

FFPC is proposing in this Application to re-align its revenue-to-cost ratios by adjusting the allocations of revenue among rate classes in order to be within the Board's target range. In addition, an adjustment is made to decrease the ratio for the General Service 50 to 999 kW and USL class below the Board's maximum value of the target range in order to maintain revenue neutrality.

The table below proposes FFPC's revenue-to-cost ratios for the years 2014-2016.

Table 7.10: Proposed Revenue-to-Cost Ratios 2014-2016

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2014	2015	2016	
	%	%	%	%
Residential	97.50	97.50	97.50	85 - 115
GS < 50 kW	97.50	97.50	97.50	80 - 120
GS > 50kW -4999 kW	120.00	120.00	120.00	80 - 120
Street Lighting	97.50	97.50	97.50	70 - 120
Unmetered Scattered Load (USL)	119.30	119.30	119.30	80 - 120

The following table provides information on calculated rate class revenue. The resulting 2014 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this Application.

Table 7.11: Calculated Rate Class Revenue

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$ 807,947	$ 1,067,699	$ 1,259,829	$ 72,148
GS < 50 kW	$ 230,962	$ 305,216	$ 347,010	$ 20,027
GS > 50kW -4999 kW	$ 369,062	$ 487,713	$ 253,058	$ 8,971
Street Lighting	$ 17,343	$ 22,919	$ 23,651	$ 1,758
Unmetered Scattered Load (USL)	$ 2,411	$ 3,186	$ 3,176	$ 129
Total	$ 1,427,725	$ 1,886,733	$ 1,886,724	$ 103,033

1

2

Appendix 7-A

2014 Updated Cost Allocation Study

Cost Allocation Hard Copy Input sheets I-6 and I-8,

Output sheets O-1 and O-2 (first page only)



2014 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet - Fort Frances Power Corporation

Total kWhs from Load Forecast	78,161,020
Total kWs from Load Forecast	68,349
Deficiency/sufficiency (RRWF 8. cell F51)	- 459,007
Miscellaneous Revenue (RRWF 5. cell F48)	103,033

			1	2	3	7	9
	ID	Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Billing Data							
Forecast kWh	CEN	78,161,020	37,751,518	13,617,679	26,376,324	366,947	48,552
Forecast kW	CDEM	68,349			67,294	1,055	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		15,558			15,558		
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	78,161,020	37,751,518	13,617,679	26,376,324	366,947	48,552
Existing Monthly Charge			$12.05	$29.03	$242.06	$1.17	$29.03
Existing Distribution kWh Rate			$0.0088	$0.0066			$0.0066
Existing Distribution kW Rate					$3.5943	$3.0509	
Existing TOA Rate					$0.60		
Additional Charges							
Distribution Revenue from Rates		$1,437,060	$807,947	$230,962	$378,397	$17,343	$2,411
Transformer Ownership Allowance		$9,335	$0	$0	$9,335	$0	$0
Net Class Revenue	CREV	$1,427,725	$807,947	$230,962	$369,062	$17,343	$2,411
						*	

* Street Light Forecast kWh has been reduced to reflect LED Retrofit conversion.



2014 Cost Allocation Model

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Sheet I8 Demand Data Worksheet - Fort Frances Power Corporation

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	15,876	8,563	3,392	3,813	86	22
Bulk Delivery CP	BCP1	-					
Total Sytem CP	DCP1	15,876	8,563	3,392	3,813	86	22
4 CP							
Transformation CP	TCP4	60,964	32,443	12,900	15,184	343	94
Bulk Delivery CP	BCP4	-					
Total Sytem CP	DCP4	60,964	32,443	12,900	15,184	343	94
12 CP							
Transformation CP	TCP12	154,679	73,753	36,889	43,308	478	251
Bulk Delivery CP	BCP12	-					
Total Sytem CP	DCP12	154,679	73,753	36,889	43,308	478	251
NON CO_INCIDENT PEAK							
1 NCP							
Classification NCP from Load Data Provider	DNCP1	18,105	9,273	4,496	4,222	86	28
Primary NCP	PNCP1	18,105	9,273	4,496	4,222	86	28
Line Transformer NCP	LTNCP1	18,105	9,273	4,496	4,222	86	28
Secondary NCP	SNCP1	13,883	9,273	4,496		86	28
4 NCP							
Classification NCP from Load Data Provider	DNCP4	67,495	34,836	16,189	16,021	343	106
Primary NCP	PNCP4	67,495	34,836	16,189	16,021	343	106
Line Transformer NCP	LTNCP4	67,495	34,836	16,189	16,021	343	106
Secondary NCP	SNCP4	51,474	34,836	16,189		343	106
12 NCP							
Classification NCP from Load Data Provider	DNCP12	166,098	78,571	41,219	44,983	1,028	297
Primary NCP	PNCP12	166,098	78,571	41,219	44,983	1,028	297
Line Transformer NCP	LTNCP12	166,098	78,571	41,219	44,983	1,028	297
Secondary NCP	SNCP12	121,115	78,571	41,219		1,028	297

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Sheet O1 Revenue to Cost Summary Worksheet - Fort Frances Powe

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate

Rate Base Assets		Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$1,427,725	$807,947	$230,962	$369,062	$17,343	$2,411
mi	Miscellaneous Revenue (mi)	$103,033	$72,148	$20,029	$8,969	$1,757	$129
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	$1,530,758	$880,096	$250,992	$378,031	$19,100	$2,539
	Factor required to recover deficiency (1 + D)	1.3215					
	Distribution Revenue at Status Quo Rates	$1,886,732	$1,067,699	$305,216	$487,713	$22,919	$3,186
	Miscellaneous Revenue (mi)	$103,033	$72,148	$20,029	$8,969	$1,757	$129
	Total Revenue at Status Quo Rates	$1,989,765	$1,139,847	$325,245	$496,683	$24,676	$3,314
	Expenses						
di	Distribution Costs (di)	$603,000	$379,275	$123,800	$87,547	$11,418	$959
cu	Customer Related Costs (cu)	$340,000	$273,985	$49,007	$15,850	$763	$395
ad	General and Administration (ad)	$714,650	$493,861	$131,893	$78,551	$9,321	$1,024
dep	Depreciation and Amortization (dep)	$197,074	$130,838	$42,869	$20,748	$2,414	$205
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0
INT	Interest	$135,041	$88,171	$28,881	$15,659	$2,144	$187
	Total Expenses	$1,989,765	$1,366,130	$376,450	$218,356	$26,060	$2,770
	Direct Allocation	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$0	$0	$0	$0	$0	$0
	Revenue Requirement (includes NI)	$1,989,765	$1,366,130	$376,450	$218,356	$26,060	$2,770
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$10,579,188	$6,677,279	$2,214,246	$1,504,474	$167,529	$15,660
gp	General Plant - Gross	$1,429,336	$933,240	$305,686	$165,744	$22,689	$1,978
accum dep	Accumulated Depreciation	($8,339,641)	($5,215,038)	($1,735,284)	($1,244,779)	($131,979)	($12,561)
co	Capital Contribution	$0	$0	$0	$0	$0	$0
	Total Net Plant	$3,668,883	$2,395,480	$784,649	$425,438	$58,239	$5,076
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$6,992,896	$3,377,546	$1,218,344	$2,359,832	$32,830	$4,344
	OM&A Expenses	$1,657,650	$1,147,121	$304,700	$181,948	$21,503	$2,378
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	*$8,650,546*	*$4,524,666*	*$1,523,044*	*$2,541,780*	*$54,333*	*$6,722*
	Working Capital	$1,124,571	$588,207	$197,996	$330,431	$7,063	$874
	Total Rate Base	$4,793,454	$2,983,687	$982,645	$755,869	$65,302	$5,950
		Rate Base Input equals Output					
	Equity Component of Rate Base	$1,917,381	$1,193,475	$393,058	$302,348	$26,121	$2,380
	Net Income on Allocated Assets	$0	($226,283)	($51,205)	$278,327	($1,384)	$545
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0
	Net Income	$0	($226,283)	($51,205)	$278,327	($1,384)	$545
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	100.00%	83.44%	86.40%	227.47%	94.69%	119.66%
	EXISTING REVENUE MINUS ALLOCATED COS	($459,007)	($486,034)	($125,458)	$159,676	($6,960)	($230)
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED	$0	($226,283)	($51,205)	$278,327	($1,384)	$545
	RETURN ON EQUITY COMPONENT OF RATE E	0.00%	-18.96%	-13.03%	92.06%	-5.30%	22.88%



2014 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Fort Frances Power Corporat

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$9.18	$16.08	$44.24	$0.75	$7.00
Customer Unit Cost per month - Directly Related	$14.41	$24.17	$66.10	$1.00	$11.15
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$22.94	$33.19	$72.00	$8.93	$19.14
Existing Approved Fixed Charge	$12.05	$29.03	$242.06	$1.17	$29.03

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 General Service Less Than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
General Plant - Gross Assets	$1,429,336	$933,240	$305,686	$165,744	$22,689	$1,978
General Plant - Accumulated Depreciation	($1,090,527)	($712,025)	($233,227)	($126,456)	($17,311)	($1,509)
General Plant - Net Fixed Assets	$338,809	$221,215	$72,460	$39,288	$5,378	$469
General Plant - Depreciation	$39,129	$25,548	$8,368	$4,537	$621	$54
Total Net Fixed Assets Excluding General Plant	$3,330,074	$2,174,266	$712,189	$386,150	$52,861	$4,607
Total Administration and General Expense	$714,650	$493,861	$131,893	$78,551	$9,321	$1,024
Total O&M	$943,000	$653,260	$172,808	$103,397	$12,181	$1,354

FFPC
FORT FRANCES POWER CORPORATION

Filing Number: EB-2013-0130
Filed: December 20, 2013

EXHIBIT EIGHT

RATE DESIGN

Exhibit 8 - Rate Design	Tab	**Schedule**	**Contents**
		1	Rate Design Overview
		2	Rate Mitigation
		3	Existing Rate Classes
		4	Existing Rate Schedule
		4	Proposed Rate Classes
		4	Proposed Rates and Charges
		5	Reconciliation of Rate Class Revenue
		6	Rate and Bill Impacts
Appendix		8-A	Existing Rates
		8-B	Proposed 2014 Rates
		8-C	Bill Impacts
		8-D	Track Changes Current and Proposed
		8-E	Retail Transmission Service Rate Work Form

RATE DESIGN OVERVIEW:

DISTRIBUTION RATE DESIGN:

This Exhibit documents the calculation of FFPC's proposed distribution rates by rate class for the 2014 Test Year based on the rate design as proposed in this Exhibit.

FFPC has determined its total 2014 service revenue requirement to be $ 1,989,765.. The total revenue offsets in the amount of $103,033 reduce FFPC's total service revenue requirement to a base revenue requirement of $1,886,732 which is used to determine the proposed distribution rates. The revenue requirement is summarized in the Table 8.1 below:

Table 8.1: Calculation of Base Revenue Requirement

Calculation of Base Revenue Requirement	
Description	**Amount**
OM&A Expenses	**$ 1,657,650**
Amortization Expense	**$ 197,074**
Interest	**$ 135,041**
PILs	**$ -**
Regulated Return on Capital	**$ -**
Service Revenue Requirement	**$ 1,989,765**
Less: Revenue Offsets	**$ 103,033**
Base Revenue Requirement	**$ 1,886,732**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. The following table shows how the base revenue requirement has been allocated to the rate classes.

Table 8.2: Calculated Class Revenue

Calculated Class Revenue - Consistent with Appendix 2-P: Calculated Revenue	2013 Proposed Base Revenue
Residential	$ 1,067,699
General Service <50 kW	$ 305,216
General Service >50 kW	$ 487,713
Street Lighting	$ 22,919
Unmetered Scattered Load	$ 3,186
Total	$ 1,886,733

Determination of Monthly Fixed Charges:

Based on applying the existing approved monthly service charges to the forecasted number of customers for 2014 and applying the existing approved distribution volumetric charge, excluding the adjustment for transformation allowance, to 2014 forecasted volumes the following table outlines FFPC's current split between fixed and variable distribution revenue:

Table 8.3: Current Fixed and Variable Split

Current Fixed/Variable Split												
Rate Classification	2014 Forecasted Number of Customers/ Connections	2013 Fixed Base Approved Rates		2014 Forecasted Volumes	2013 Variable Base Approved Rates	2014 Fixed Base Revenue with 2013 Approved Rates	2014 Variable Base Revenue with 2013 Approved Rates	2014 Total Base Revenue with 2013 Approved Rates Including Transformer	Transformer Allowance	2014 Total Base Revenue with 2013 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	3290	$ 12.05	kWh	37,751,518	$ 0.0088	$ 475,734	$ 332,213	$ 807,947		$ 807,947	58.88%	41.12%
General Service <50 kW	405	$ 29.03	kWh	13,617,679	$ 0.0066	$ 141,086	$ 89,877	$ 230,962		$ 230,962	61.09%	38.91%
General Service >50 kW	47	$ 242.06	kW	67,294	$ 3.5943	$ 136,522	$ 241,875	$ 378,397	$9,335	$ 369,062	36.99%	65.54%
Unmetered Scattered Load	6	$ 29.03	kWh	48,552	$ 0.0066	$ 2,090	$ 320	$ 2,411		$ 2,411	86.71%	13.29%
Street Lighting	1006	$ 1.17	kW	1,055	$ 3.0509	$ 14,124	$ 3,219	$ 17,343		$ 17,343	81.44%	18.56%
kW						$ 769,556	$ 667,504	$ 1,437,060		$ 1,427,725	65.02%	35.48%
Transformer Ownership Allowance-Annual Base kW:				15,558				Rate of Transfomer Allowance for Ownership:			-$0.60	-$9,335

Consistent with Board Decisions on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities as well as the Board's Decision on Atikokan Hydro's 2012 cost of service application, FFPC proposes to maintain the current fixed/variable proportions for all rate classes and the proposed fixed rates, as shown below:

Table 8.4**: Fixed Charge Analysis**

Fixed Charge Analysis

Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total	Proposed Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2013 Rates From OEB Approved Tariff	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)
Residential	41.12%	58.88%	100.00%	**$18.79**	$12.05	$20.88
GS < 50 kW	38.91%	61.09%	100.00%	**$43.62**	$29.03	$28.33
GS >50 to 4999 kW	63.01%	36.99%	100.00%	**$165.98**	$242.06	$44.34
Street Lighting	18.56%	81.44%	100.00%	**$1.60**	$1.17	$8.75
Unmetered and Scattered	13.29%	86.71%	100.00%	**$38.24**	$29.03	$16.28
TOTAL						

Proposed Volumetric Charges:

The volumetric distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2014 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides FFPC's calculations of its proposed volumetric distribution charges for the 2014 Test Year assuming the fixed/variable split used in designing the monthly service charge.

Table 8.5: Proposed Fixed and Volumetric Rates for 2014 Test Year

Distribution Rate Allocation Between Fixed & Variable Rates For 2014 Test Year

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Proposed Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue
Residential	1,259,829	66.77%	18.79	$0.0137	$ 741,810	$ 518,019		1,259,829
GS < 50 kW	347,010	18.39%	43.62	$0.0099	$ 211,974	$ 135,035		347,010
GS >50 to 4999 kW	253,058	13.41%	165.98	$2.5081	$ 93,610	$ 159,448	$ 9,335	262,393
Street Lighting	23,651	1.25%	1.60	$4.1605	$ 19,261	$ 4,389		23,651
Unmetered and Scattered	3,176	0.17%	38.24	$0.0087	$ 2,753	$ 422		3,176
TOTAL	**1,886,723**	**100.00%**			**$ 1,069,409**	**$ 817,314**	**$ 9,335**	**$ 1,896,058**
					Total Revenue	**1,886,723**		

Currently, FFPC provides a Transformer Allowance to those customers that own their transformation facilities. FFPC proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. However, in order to ensure FFPC collects the proposed distribution revenue assigned to the rate class, which provides a Transformer Allowance, the total amount or "cost" of the Transformer Allowance for the rate class needs to be collected in the distribution volumetric rates from all customers in the class. This will allow FFPC to collect distribution revenue from the rate class at the "gross" level. Then this will provide a Transformer Allowance which will reduce the gross distribution revenue to a "net" level. The net level amount will be equivalent to the proposed distribution assigned to the rate class.

As a result, the amount of Transformer Allowance expected to be provided to the General Service >50 to 4,999 kW customers that own their transformers is included in the volumetric charge for the class. The proposed "net" volumetric charge of $2.5081 per kW for the General Service 50 to 4,999 kW class is increased by $0.1387 per kW to include $9,335 or the "cost" of the Transformer Allowance in the General Service 50 to 4,999 kW class volumetric charge. This means the "gross" proposed distribution volumetric charge for this class will be $2.6468.

Proposed Distribution Rates:

The following table sets out FFPC's proposed 2014 electricity distribution rates based on the foregoing calculations.

Table 8.6: 2014 Base Revenue Distribution Rates

2014 TEST YEAR - BASE REVENUE DISTRIBUTION RATES				
Customer Class	Connection	Customer	kW	kWh
Residential		$ 18.79		$ 0.0137
GS < 50 kW		$ 43.62		$ 0.0099
GS >50 to 4999 kW		$ 165.98	$ 2.5081	
Street Lighting	$ 1.60		$ 4.1605	
Unmetered and Scattered		$ 38.24		$ 0.0087

RETAIL TRANSMISSION SERVICE RATES

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "RTSR_Adjustment_Work_Form – version 4.0" and instructions on July 17, 2013 for distributors to complete as part of their 2014 electricity rate applications. FFPC has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.10 is reproduced from the Board model and indicates the new RTSR's**.** FFPC used the RRR 2.1.5 2012 billing determinants but changed the Street Lighting consumption to adjust for the LED retrofit as detailed in Exhibit 3.

Table 8.7: Final 2014 RTS Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0067	$ 0.0016
General Service Less Than 50 kW	kWh	$ 0.0061	$ 0.0014
General Service 50 to 4,999 kW	kW	$ 2.4949	$ 0.5770
Unmetered Scattered Load	kWh	$ 0.0061	$ 0.0014
Street Lighting	kW	$ 1.8817	$ 0.4461

Retail Service Charge

FFPC is not proposing any changes to the Retail Service Charges as below:

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Wholesale Market Service Charge

FFPC is not proposing any change to the Wholesale Market Service Charge of $0.0044.

Rural Rate Protection Charge

FFPC is not proposing any change to the Rural Rate Protection Charge of $0.0012

Smart Metering Entity Charge

FFPC will be continue to charge Residential and General Service <50 kW the IESO Smart Meter Entity Charge of $0.79 per month until October 31, 2018.

Stranded Meters

FFPC is seeking disposition of its stranded meter costs. FFPC's rate order for its Smart Meter Rate Application EB-2012-0327 effective November 1, 2012 issued a revised Tariff of Rates and Charges. FFPC was authorized to use the established sub-account Stranded Meter Costs of USoA 1555, Smart Meters- Sub-account Stranded Meters, to record and track the remaining costs of the stranded conventional meters. The order also stated that the balance of the sub-account should be brought forward for disposition as part of FFPC's next cost of service application. The complete review can be found in Exhibit 9, Tab 3.

The net book value of the stranded conventional meters at December 31, 2012 was $92,216.

Table 8.8: Stranded Meter Treatment, 2006-2013

Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ 351,835	$ 216,225		$ 135,610		$ 135,610
2007		$ 382,601	$ 230,248		$ 152,353		$ 152,353
2008		$ 390,590	$ 244,323		$ 146,267		$ 146,267
2009		$ 391,865	$ 258,449		$ 133,416		$ 133,416
2010		$ 391,865	$ 272,575		$ 119,290		$ 119,290
2011		$ 391,865	$ 286,700		$ 105,165		$ 105,165
2012		$ 391,865	$ 299,649		$ 92,216		$ 92,216
2013	(1)	$ 391,865	$ 299,649		$ 92,216		$ 92,216

FFPC's rate order for its Smart Meter Rate Application EB-2012-0327 effective November 1, 2012, ordered the recovery of FFPC's Smart Meter costs from all metered rate classes, including GS>50kW rate class. The decision and order stated regarding 'Costs Beyond Minimum Functionality', that:

"FFPC documented $54,402 capital costs and $14,119 operating expenses for costs beyond minimum functionality related to FFPC's smart meter deployment of 47 smart meter for the GS >50 kW rate class, …"

FFPC, in the application, proposed that due to the small number of GS>50 kW customers (47) served by FFPC and the fact that FFPC's larger energy consumers would be excluded from the potential consumption analysis and conservation opportunities that would result from this technology, FFPC sought to include the rate class GS>50 kW in FFPC's Smart Meter implementation program and to seek recovery of these specific customer costs from within this rate class.

The Board approved the recovery of these costs as included and justified in the Application and approved the following rate riders for capital (SMDR) and incremental (SMIRR) cost recovery in the table below:

Table 8.9: Smart Meter Rate Riders- EB-2012-0327

EB-2012-0327 -Smart Meter Disposition Rider (SMDR) & Smart Meter Interim Rate Rider (SMIRR)					
	SMDR	**SMIRR**			
Residential	$3.58	$3.43			
General Service <50 kW	$13.42	$7.19			
General Service >50 kW	$20.71	$9.97			

FFPC established the value of each meter type by analyzing the age of each meter, the initial capital cost (i.e. GS>50kW transformer type meters capital costs $600 per meter- versus self contained mechanical meter- $45.) and any additional capital costs borne by FFPC for the metering installation-i.e. potential and current transformer, etc. FFPC established the stranded meter net book value by rate class as detailed in the column marked '2008'. Subsequent years 2009-2012 are reduced by depreciation.

The table below reviews FFPC's stranded meter history and proposed Disposition Rate Rider, recovered from all metered rate classes:

Table 8.10: Proposed Stranded Meter Disposition Rate Riders

Stranded Meter History and Cost Allocation							
Rate	# Meters in Service	2008	2009	2010	2011	2012	Stranded Meter Disposition Rate Rider Per Customer
							Monthly Charge
Residential	3283	$61,001	$56,192	$49,998	$44,287	$38,578	$0.98
GS <50 kW	422	$66,471	$61,020	$53,975	$47,459	$40,944	$8.09
GS >50 kW	47	$18,795	$16,204	$15,317	$13,419	$12,694	$22.51
					$0		
Net Book Value	3752	**$146,267**	**$133,416**	**$119,290**	**$105,165**	**$92,216**	
Accumulated Amortization		*$244,323*	*$258,449*	*$272,575*	*$286,700*	*$299,649*	
Gross Book Value		$390,590	$391,865	$391,865	$391,865	$391,865	

FFPC is proposing a one-year recovery for Stranded Meter Rate Recovery (SMRR) as above from all rate classes.

Specific Service Charge

FFPC is proposing a review of existing Specific Service Charges as detailed in the prior Exhibit 3, Tab 3, Schedule 2. FFPC is proposing the removal of unused charges and a revision of some existing charges to recover current business costs. A summary of the proposed new Specific Charges is below:

Table 8.11: Specific Service Charges

SPECIFIC SERVICE CHARGES - Effective May 1, 2013	May 1, 2014 Proposed	
Customer Administration	**Metric**	**Current**
Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	25.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if appl	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account	Metric	Current
Late Payment - per month	%	1.5
Late Payment - per annum	%	19.56
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Other	Metric	Current
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call - customer-owned equipment	$	65.00
Service call - after regular hours	$	165.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

Rates and Charges Not Appearing on the Tariff Sheet

FFPC does not have any rates or charges in our Conditions of Service that do not appear on our tariff sheet.

LOSS FACTOR

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

Total Loss Factor:

FFPC has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2008 to 2012. The calculations are summarized in Table 8.12 below.

After consultation with OEB Board Staff, FFPC entered into 'H', Supply Facility Loss Factor of '1'.

FFPC's metering is secondary or 'downstream' of the two primary transformers located in FFPC's municipal transformer station. BB: The amount metered downstream of the two primary transformers – is the amount of kWh metered at these points in a month exactly the amount used on invoice from the IESO for the month. If yes, then this is correct. If not, then the IESO is most like adding a SFLF factor to the reading to estimate the reading on the upstream side of the primary transformers which is typical where the IESO transacts power with the LDC. FFPC does not operate or own any distribution stations.

Table 8.12: Line Loss Calculation

		Historical Years					5-Year Average
		2008	2009	2010	2011	2012	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)						0
A(2)	"Wholesale" kWh delivered to distributor (lower value)	87,543,080	86,145,680	84,047,771	83,026,301	80,138,104	84,180,187
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	87,543,080	86,145,680	84,047,771	83,026,301	80,138,104	84,180,187
D	"Retail" kWh delivered by distributor	83,874,392	82,503,841	79,739,754	79,562,547	76,310,423	80,398,191
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						0
F	Net "Retail" kWh delivered by distributor = **D - E**	83,874,392	82,503,841	79,739,754	79,562,547	76,310,423	80,398,191
G	Loss Factor in Distributor's system = **C / F**	1.0437	1.0441	1.0540	1.0435	1.0502	1.0470
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1	1	1	1	1	1
	Total Losses						
I	Total Loss Factor = **G x H**	**1.0437**	**1.0441**	**1.0540**	**1.0435**	**1.0502**	**1.0470**

FFPC has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2008 to 2012. As a result of this analysis, FFPC is proposing to change the 2014 Total Loss Factor at the calculated rate of 1.047.

Total Loss Factors by Class:

Table 8.13 sets out the class-specific Loss Factors used by FFPC in the calculation of commodity and other non-distribution charges for the 2014 Test Year.

Table 8.13: Total Loss Factors

Loss Factors	
Supply Facilities Loss Factor (5 Year Average)	1.0000
Total Loss Factor - Secondary Metered Customers < 5,000 kW	1.0470
Total Loss Factor - Secondary Metered Customers > 5,000 kW	N/A
Total Loss Factor - Primary Metered Customers < 5,000 kW	1.0365
Total Loss Factor - Primary Metered Customers < 5,000 kW	N/A

FFPC confirms that it is not an embedded distributor and that no loss study has been recommended in a previous decision by the Board.

Materiality Analysis on Distribution Losses:

FFPC's proposed Distribution Loss Adjustment factor is 4.7%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, FFPC is not required to provide a explanation of, or justification for, its loss adjustment factor.

RATE MITIGATION:

FFPC submits that the bill impacts of its proposed 2014 electricity distribution rates for all rate classes are under 10% and therefore do not require rate mitigation.

The existing Tariff of Rates and Charges, EB-2012-0083, have rate riders for the metered rate classes for both the Disposition of Smart Meter Costs (sunset date-November 30, 2013) and the Recovery of Smart Meter Incremental Revenue Requirement. The expiry of both Smart Meter charges offset the increases resulting from FFPC's proposed Fixed Monthly Service charge increases.

The existing tariff also included rate riders for:

- Disposition of Deferral/Variance Account (2013), effective until April 30, 2015,
- Disposition of Global Adjustment Sub-Account (2013). Effective until April 30, 2015.

The proposed additional rate riders for:

- Recovery of Deferral/Variance Account (2014), effective until April 30, 2016,
- Disposition of Global Adjustment Sub-Account (2014). Effective until April 30, 2016

These additional proposed DVA dispositions, combined with the existing rate riders, offset the increases resulting from other rate charge adjustments.

The total bill impact for the Street Lights class is an increase of 8.97%. This increase is primarily due to increases in the Distribution Service Charge and Volumetric Rate to BB: recover allocated costs. FFPC's Street Light rates have been historically lower than neighbouring LDCs and this slight rate increase realigns charges to closer to industry levels.

EXISTING RATE CLASSES:

Residential:

This rate class governs all services intended to supply electrical energy to buildings or sections of buildings devoted to living quarters such as houses, living accommodations at the rear of stores, self-contained and individually metered suites. These services are commonly referred to as Residential or Domestic Services.

General Service Less Then 50kW:

This classification will normally be applicable to small industry, departmental or larger stores such as supermarkets, shopping centres, storage buildings, large garages, restaurants, office buildings, institutions, hotels, hospitals, schools, colleges, arenas, apartment blocks or buildings and other comparable establishments and whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW.

General Service Greater Than 50 to 4,999 kW:

This rate class will normally be applicable to small industry, departmental or larger stores such as supermarkets, shopping centres, storage buildings, large garages, restaurants, office buildings, institutions, hotels, hospitals, schools, colleges, arenas, apartment blocks or buildings and other comparable establishments and whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW.

Unmetered Scattered Load:

This rate classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters,

telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. FFPC charges on a monthly 'Per Customer' charge and not the 'Per Connection' charge.

Street Lighting:

This classification refers to an account for roadway lighting with a Municipality within the service boundaries. The consumption for these customers is based on the calculated load times the established hours of use in the OEB load shape template.

EXISTING RATE SCHEDULE

FFPC has attached the Board's Decision and Order from its 2013 Rate Application (EB-2012-0083) in Appendix 8-A, which contains a complete schedule of existing rates.

PROPOSED RATE CLASSES:

Fort Frances Power Corporation is not requesting any changes to the existing rate classes.

PROPOSED RATES AND CHARGES:

Please see Appendix 8-B for FFPC's proposed Tariff of Rates and Charges effective May 1, 2014.

RECONCILIATION OF RATE CLASS REVENUE

The following table provides the reconciliation between the 2014 distribution rate calculations based on the 2014 Proposed Rates and the total base revenue required. The reconciliation yields an acceptable difference due to changes in customer numbers and rounding of numbers.

Table 8.14: Revenue Reconciliation

Revenue Reconciliation

Rate Class	Customers/ Connections	Number of			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	3,292	3,287	3,290	37,751,518		$ 18.79	$ 0.0137		$1,258,912	$ 1,259,829		$1,259,829	$ 917
GS < 50 kW	Customers	407	403	405	13,617,679		$ 43.62	$ 0.0099		$346,808	$ 347,010		$ 347,010	$ 202
GS > 50 to 4,999 kW	Customers	47	47	47	26,376,324	67,294	$ 165.98		$2.5081	$262,393	$ 253,058	$ 9,335	$ 262,393	$ 0
Streetlighting	Connections	1,006	1,006	1,006	366,947	1,055	$ 1.60		$4.1605	$23,705	$ 23,651		$ 23,651	-$ 54
USL	Customers	6	6	6	48,552		$ 38.24	$ 0.0087		$3,176	$ 3,176		$ 3,176	$ 0
				0						$0			$ -	$ -
Total										$1,894,993	$ 1,886,724	$ 9,335	$1,896,059	$ 1,066

RATE AND BILL IMPACTS:

Appendix C to this Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are shown using the applicable current approved rates and the proposed 2014 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

APPENDIX 8-A

Fort Frances Power Corporation

Existing Tariff of Rates and Charges, Effective May 1, 2013

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0083

RESIDENTIAL SERVICE CLASSIFICATION

This section governs all services intended to supply electrical energy to buildings or sections of buildings devoted to living quarters such as houses, living accommodations at the rear of stores, self-contained and individually metered suites. These services are commonly referred to as Residential or Domestic Services. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.05
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until November 30, 2013	$	3.58
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	3.43
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0088
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2015	$/kWh	(0.0004)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0063)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0066
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0015

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0083

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This type of service will normally be applicable to small industry, departmental or larger stores such as supermarkets, shopping centres, storage buildings, large garages, restaurants, office buildings, institutions, hotels, hospitals, schools, colleges, arenas, apartment blocks or buildings and other comparable establishments and whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	29.03
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until November 30, 2013	$	13.42
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	7.19
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0066
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2015	$/kWh	(0.0004)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0063)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0013

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0083

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This type of service will normally be applicable to small industry, departmental or larger stores such as supermarkets, shopping centres, storage buildings, large garages, restaurants, office buildings, institutions, hotels, hospitals, schools, colleges, arenas, apartment blocks or buildings and other comparable establishments and whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	242.06
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until November 30, 2013	$	20.71
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	9.97
Distribution Volumetric Rate	$/kW	3.5943
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2015	$/kW	(0.1671)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	(2.4469)
Retail Transmission Rate - Network Service Rate	$/kW	2.4488
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.5516

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0083

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	29.03
Distribution Volumetric Rate	$/kWh	0.0066
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2015	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0013

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0083

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality within the service boundaries. The consumption for these customers is based on the calculated load times the established hours of use in the OEB load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1.17
Distribution Volumetric Rate	$/kW	3.0509
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2015	$/kW	(0.1545)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	(2.2660)
Retail Transmission Rate - Network Service Rate	$/kW	1.8469
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.4265

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0083

MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0083

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Orderof the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges forthe Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	20.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	45.00
Disconnect/Reconnect Charge – At Pole – After Hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary Service – Install & remove – overhead – no transformer	$	500.00
Temporary Service – Install & remove – underground – no transformer	$	300.00
Temporary Service Install & Remove – Overhead – With Transformer	$	1,000.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Fort Frances Power Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0083

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0406
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0302
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

APPENDIX 8-B

Fort Frances Power Corporation

Proposed Tariff of Rates and Charges, Effective May 1, 2014

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0130

RESIDENTIAL SERVICE CLASSIFICATION

This section governs all services intended to supply electrical energy to buildings or sections of buildings devoted to living quarters such as houses, living accommodations at the rear of stores, self-contained and individually metered suites. These services are commonly referred to as Residential or Domestic Services. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	18.79
Distribution Volumetric Rate	$/kWh	0.0137
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	(0.0004)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0063)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0016
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$	0.98
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0047)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kWh	(0.0004)
Rate Adder for GEA Direct	$	0.07

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0130

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This type of service will normally be applicable to small industry, departmental or larger stores such as supermarkets, shopping centres, storage buildings, large garages, restaurants, office buildings, institutions, hotels, hospitals, schools, colleges, arenas, apartment blocks or buildings and other comparable establishments and whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component		
Service Charge	$	43.62
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0099
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	(0.0004)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0063)
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$	8.09
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0014
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0047)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kWh	(0.0004)
Rate Adder for GEA Direct	$	0.07

MONTHLY RATES AND CHARGES - Regulatory Component		
Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

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EB-2013-0130

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This type of service will normally be applicable to small industry, departmental or larger stores such as supermarkets, shopping centres, storage buildings, large garages, restaurants, office buildings, institutions, hotels, hospitals, schools, colleges, arenas, apartment blocks or buildings and other comparable establishments and whose monthly average peak demand is equal to or greater than, or forecast to be equal to or greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	165.98
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$	22.51
Distribution Volumetric Rate	$/kW	2.5081
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kW	(0.1671)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	(2.4469)
Retail Transmission Rate - Network Service Rate	$/kW	2.4949
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.5770
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kW	0.0063
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30, 2016 Applicable only for Non-RPP Customers	$/kW	(1.8481)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kW	(0.1381)
Rate Adder for GEA Direct	$	0.07

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

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EB-2013-0130

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.24
Distribution Volumetric Rate	$/kWh	0.0087
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0014
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kWh	(0.0001)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kWh	(0.0004)
Rate Adder for GEA Direct	$	0.07

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

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EB-2013-0130

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality within the service boundaries. The consumption for these customers is based on the calculated load times the established hours of use in the OEB load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.60
Distribution Volumetric Rate	$/kW	4.1605
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kW	(0.1545)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	(2.2660)
Retail Transmission Rate - Network Service Rate	$/kW	1.8817
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.4461
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kW	(0.6102)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30, 2016 Applicable only for Non-RPP Customers	$/kW	(1.6400)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kW	(0.1225)
Rate Adder for GEA Direct	$	0.07

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

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EB-2013-0130

MICROFIT SERVICE CLASSIFICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kw	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	($1.00)

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0130

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	25.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account		
Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00

Other		
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	65.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Fort Frances Power Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0130

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the re	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.5000
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.3000
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.3000)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0470
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0365
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	N/A

APPENDIX 8-C

Fort Frances Power Corporation

Bill Impacts for Proposed

Tariff of Rates and Charges, Effective May 1, 2014

Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed a

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 12.0500	1	$ 12.05	$ 18.7900	1	$ 18.79	$ 6.74	55.93%
Smart Meter Rate Adder (SMIRR)	Monthly	$ 3.4300	1	$ 3.43		1	$ -	-$ 3.43	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0088	800	$ 7.04	$ 0.0137	800	$ 10.96	$ 3.92	55.68%
Smart Meter Disposition Rider	Monthly	$ 3.5800	1	$ 3.58		1	$ -	-$ 3.58	-100.00%
Stranded Meter Charge	Monthly		800	$ -	$ 0.9800	1	$ 0.98	$ 0.98	
Sub-Total A (excluding pass through)				$ 26.10			$ 30.73	**$ 4.63**	**17.74%**
Rate Rider for DVA (2013)	per kWh	-$ 0.0004	800	-$ 0.32	-$ 0.0004	800	-$ 0.32	$ -	0.00%
Rate Rider Global Adjust (2013)	per kWh								
Rate Rider for DVA (2014)	per kWh			$ -	$ 0.0002	800	$ 0.16		
Rate Rider CGAAP Changes	per kWh			$ -	-$ 0.0004	800	-$ 0.32		
GEA Rate Adder	Monthly				$ 0.0700	1	$ 0.07	$ 0.07	
Line Losses on Cost of Power		$ 0.0839	32.48	$ 2.73	$ 0.0839	37.60	$ 3.16	$ 0.43	15.76%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.30**			**$ 34.27**	**$ 4.97**	**16.96%**
RTSR - Network	per kWh	$ 0.0066	832	$ 5.49	$ 0.0067	838	$ 5.61	$ 0.12	2.14%
RTSR - Line and Transformation Connection	per kWh	$ 0.0015	832	$ 1.25	$ 0.0016	838	$ 1.34	$ 0.09	7.32%
Sub-Total C - Delivery (including Sub-Total B)				**$ 36.04**			**$ 41.22**	**$ 5.18**	**14.37%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	832	$ 3.66	$ 0.0044	838	$ 3.69	$ 0.02	0.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	832	$ 1.00	$ 0.0012	838	$ 1.01	$ 0.01	0.62%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0047	800	$ 3.76	$ 0.0047	800	$ 3.76	$ -	0.00%
TOU - Off Peak		$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak		$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak		$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	800	$ 60.00	$ 0.0750	800	$ 60.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 111.85**			**$ 117.05**	**$ 5.21**	**4.66%**
HST		13%		$ 14.54	13%		$ 15.22	$ 0.68	4.66%
Total Bill (including HST)				$ 126.39			$ 132.27	$ 5.88	4.66%
Ontario Clean Energy Benefit [1]				-$ 12.64			-$ 13.23	-$ 0.59	4.67%
Total Bill on TOU (including OCEB)				**$ 113.75**			**$ 119.04**	**$ 5.29**	**4.65%**
Total Bill on RPP (before Taxes)				**$ 104.71**			**$ 109.92**	**$ 5.21**	**4.97%**
HST		13%		$ 13.61	13%		$ 14.29	$ 0.68	4.97%
Total Bill (including HST)				$ 118.32			$ 124.21	$ 5.88	4.97%
Ontario Clean Energy Benefit [1]				-$ 11.83			-$ 12.42	-$ 0.59	4.99%
Total Bill on RPP (including OCEB)				**$ 106.49**			**$ 111.79**	**$ 5.29**	**4.97%**
Loss Factor (%)		4.06%			4.70%				

Bill Impacts

Customer Class: General <50 kW

TOU / non-TOU: TOU

Consumption 2,000 kWh May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 29.0300	1	$ 29.03	$ 43.6200	1	$ 43.62	$ 14.59	50.26%
Smart Meter Rate Adder (SMIRR)	Monthly	$ 7.1900	1	$ 7.19		1	$ -	-$ 7.19	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0066	2,000	$ 13.20	$ 0.0099	2,000	$ 19.80	$ 6.60	50.00%
Smart Meter Disposition Rider	Monthly	$ 13.4200	1	$ 13.42		1	$ -	-$ 13.42	-100.00%
Stranded Meter Charge	Monthly		2,000	$ -	$ 8.0900	1	$ 8.09	$ 8.09	
Sub-Total A (excluding pass through)				$ 62.84			$ 71.51	**$ 8.67**	**13.80%**
Rate Rider for DVA (2013)	per kWh	-$ 0.0004	2,000	-$ 0.80	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider Global Adjust (2013)	per kWh								
Rate Rider for DVA (2014)	per kWh				$ 0.0003	2,000	$ 0.60		
Rate Rider CGAAP Changes	per kWh				-$ 0.0004	2,000	-$ 0.80		
GEA Rate Adder	Monthly			$ -	$ 0.0700	1	$ 0.07	$ 0.07	
Line Losses on Cost of Power		$ 0.0839	81.20	$ 6.81	$ 0.0839	94.00	$ 7.89	$ 1.07	15.76%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 69.64**			**$ 79.26**	**$ 9.61**	**13.80%**
RTSR - Network	per kWh	$ 0.0060	2081	$ 12.49	$ 0.0061	2094	$ 12.77	$ 0.29	2.29%
RTSR - Line and Transformation Connection	per kWh	$ 0.0013	2081	$ 2.71	$ 0.0014	2094	$ 2.93	$ 0.23	8.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 84.84**			**$ 94.96**	**$ 10.13**	**11.94%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2081	$ 9.16	$ 0.0044	2094	$ 9.21	$ 0.06	0.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2081	$ 2.50	$ 0.0012	2094	$ 2.51	$ 0.02	0.62%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0047	2000	$ 9.40	$ 0.0047	2000	$ 9.40	$ -	0.00%
TOU - Off Peak		$ 0.0670	512	$ 34.30	$ 0.0670	512	$ 34.30	$ -	0.00%
TOU - Mid Peak		$ 0.1040	144	$ 14.98	$ 0.1040	144	$ 14.98	$ -	0.00%
TOU - On Peak		$ 0.1240	144	$ 17.86	$ 0.1240	144	$ 17.86	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750	0	$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 173.28**			**$ 183.48**	**$ 10.20**	**5.89%**
HST		13%		$ 22.53	13%		$ 23.85	$ 1.33	5.89%
Total Bill (including HST)				$ 195.80			$ 207.33	$ 11.52	5.89%
Ontario Clean Energy Benefit [1]				-$ 19.58			-$ 20.73	-$ 1.15	5.87%
Total Bill on TOU (including OCEB)				**$ 176.22**			**$ 186.60**	**$ 10.37**	**5.89%**
Total Bill on RPP (before Taxes)				**$ 106.14**			**$ 116.34**	**$ 10.20**	**9.61%**
HST		13%		$ 13.80	13%		$ 15.12	$ 1.33	9.61%
Total Bill (including HST)				$ 119.94			$ 131.46	$ 11.52	9.61%
Ontario Clean Energy Benefit [1]				-$ 11.99			-$ 13.15	-$ 1.16	9.67%
Total Bill on RPP (including OCEB)				**$ 107.95**			**$ 118.31**	**$ 10.36**	**9.60%**
Loss Factor (%)		4.06%			4.70%				

Bill Impacts

Customer Class: General >50 - 4,999 kW

TOU / non-TOU: non-TOU

	Consumption	**31,800**	**kWh**	May 1 - October 31								
	Demand	**100**	**kW**									
		Current Board-Approved				**Proposed**				**Impact**		
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**		**Rate ($)**	**Volume**	**Charge ($)**		**$ Change**	**% Change**	
Monthly Service Charge	Monthly	$ 242.0600	1	$ 242.06		$ 165.9800	1	$ 165.98		-$ 76.08	-31.43%	
Smart Meter Rate Adder (SMIRR	Monthly	$ 9.9700	1	$ 9.97			1	$ -		-$ 9.97	-100.00%	
Distribution Volumetric Rate	per kW	$ 3.5943	100	$ 359.43		$ 2.5081	100	$ 250.81		-$ 108.62	-30.22%	
Smart Meter Disposition Rider	Monthly	$ 20.7100	1	$ 20.71			1	$ -		-$ 20.71	-100.00%	
Stranded Meter Charge	Monthly			$ -		$ 22.5100	1	$ 22.51		$ 22.51		
Sub-Total A (excluding pass through)				$ 632.17				$ 439.30		**-$ 192.87**	**-30.51%**	
Rate Rider for DVA (2013)	per kW	-$ 0.1671	100	-$ 16.71		-$ 0.1671	100	-$ 16.71		$ -	0.00%	
Rate Rider Global Adjust	per kW	-$ 2.4469	100	-$ 244.69		-$ 2.4469	100	-$ 244.69				
Rate Rider for DVA (2014)	per kW					$ 0.0063	100	$ 0.63				
Rate Rider CGAAP Changes	per kW					-$ 0.1381	100	-$ 13.81				
Rate Rider DVA Global (2014)	per kW		2,000	$ -		-$ 1.8481	100	-$ 184.81		-$ 184.81		
Line Losses on Cost of Power		$ 0.0839	1,291.08	$ 108.35		$ 0.0839	1,494.60	$ 125.43		$ 17.08	15.76%	
GEA Rate Adder	Monthly			$ -		$ 0.0700	1	$ 0.07		$ 0.07		
Sub-Total B - Distribution (includes Sub-Total A)				**$ 479.12**				**$ 105.41**		**-$ 373.71**	**-78.00%**	
RTSR - Network	per kW	$ 2.4488	100	$ 244.88		$ 2.4949	100	$ 249.49		$ 4.61	1.88%	
RTSR - Line and Transformation	per kW	$ 0.5516	100	$ 55.16		$ 0.5770	100	$ 57.70		$ 2.54	4.60%	
Sub-Total C - Delivery (including Sub-Total B)				**$ 779.16**				**$ 412.60**		**-$ 366.56**	**-47.05%**	
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	31800	$ 139.92		$ 0.0044	31800	$ 139.92		$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	31800	$ 38.16		$ 0.0012	31800	$ 38.16		$ -	0.00%	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25		$ 0.2500	1	$ 0.25		$ -	0.00%	
Debt Retirement Charge (DRC)	per kWh	$ 0.0047	31800	$ 149.46		$ 0.0047	31800	$ 149.46		$ -	0.00%	
TOU - Off Peak		$ 0.0670		$ -		$ 0.0670	0	$ -		$ -		
TOU - Mid Peak		$ 0.1040		$ -		$ 0.1040	0	$ -		$ -		
TOU - On Peak		$ 0.1240		$ -		$ 0.1240	0	$ -		$ -		
Energy - RPP - Tier 1		$ 0.0750		$ -		$ 0.0750	0	$ -		$ -		
Energy - Spot & Global		$ 0.1000	31800	$ 3,180.00		$ 0.1000	31800	$ 3,180.00		$ -	0.00%	
Total Bill on Spot (before Taxes)				**$ 4,286.95**				**$ 3,920.39**		**-$ 366.56**	**-8.55%**	
HST		13%		$ 557.30		13%		$ 509.65		-$ 47.65	-8.55%	
Total Bill (including HST)				$ 4,844.25				$ 4,430.04		-$ 414.21	-8.55%	
Ontario Clean Energy Benefit [1]										$ -		
Total Bill on RPP (including OCEB)				**$ 4,844.25**				**$ 4,430.04**		**-$ 414.21**	**-8.55%**	
Loss Factor (%)		4.06%				4.70%						

Bill Impacts

Customer Class: Unmetered Scattered Load

TOU / non-TOU: non-TOU

May 1 - October 31 **Consumption** 2,000 kWh May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 29.0300	1	$ 29.03	$ 38.2400	1	$ 38.24	$ 9.21	31.73%
Smart Meter Rate Adder (SMIRR)	Monthly		1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0066	2,000	$ 13.20	$ 0.0087	2,000	$ 17.40	$ 4.20	31.82%
Smart Meter Disposition Rider	Monthly		1	$ -		1	$ -	$ -	
Stranded Meter Charge	Monthly			$ -		1	$ -	$ -	
Sub-Total A (excluding pass through)				$ 42.23			$ 55.64	**$ 13.41**	**31.75%**
Rate Rider for DVA (2013)	per kWh	-$ 0.0004	2,000	-$ 0.80	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Rate Rider for DVA (2013)	per kWh				-$ 0.0001	2,000	-$ 0.20		
Rate Rider CGAAP (2014)	per kWh				-$ 0.0004	2,000	-$ 0.80		
GEA Rate Adder	Monthly		2,000	$ -	$ 0.0700	1	$ 0.07	$ 0.07	
Line Losses on Cost of Power		$ 0.0839	81.20	$ 6.81	$ 0.0839	94.00	$ 7.89	$ 1.07	15.76%
Smart Meter Entity Charge	Monthly		1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48.24**			**$ 61.80**	**$ 13.55**	**28.09%**
RTSR - Network	per kWh	$ 0.0060	2081	$ 12.49	$ 0.0061	2094	$ 12.77	$ 0.29	2.29%
RTSR - Line and Transformation	per kWh	$ 0.0013	2081	$ 2.71	$ 0.0014	2094	$ 2.93	$ 0.23	8.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 63.44**			**$ 77.50**	**$ 14.07**	**22.17%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2081	$ 9.16	$ 0.0044	2094	$ 9.21	$ 0.06	0.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2081	$ 2.50	$ 0.0012	2094	$ 2.51	$ 0.02	0.62%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0047	2000	$ 9.40	$ 0.0047	2000	$ 9.40	$ -	0.00%
TOU - Off Peak		$ 0.0670		$ -	$ 0.0670	0	$ -	$ -	
TOU - Mid Peak		$ 0.1040		$ -	$ 0.1040	0	$ -	$ -	
TOU - On Peak		$ 0.1240		$ -	$ 0.1240	0	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	2000	$ 150.00	$ 0.0750	2000	$ 150.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880	0	$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 84.74**			**$ 98.88**	**$ 14.14**	**16.68%**
HST		13%		$ 11.02	13%		$ 12.85	$ 1.84	16.68%
Total Bill (including HST)				$ 95.76			$ 111.73	$ 15.98	16.68%
Ontario Clean Energy Benefit [1]				-$ 9.58			-$ 11.17	-$ 1.59	16.60%
Total Bill on TOU (including OCEB)				**$ 86.18**			**$ 100.56**	**$ 14.39**	**16.69%**
Total Bill on RPP (before Taxes)				**$ 234.74**			**$ 248.88**	**$ 14.14**	**6.02%**
HST		13%		$ 30.52	13%		$ 32.35	$ 1.84	6.02%
Total Bill (including HST)				$ 265.26			$ 281.23	$ 15.98	6.02%
Ontario Clean Energy Benefit [1]				-$ 26.53			-$ 28.12	-$ 1.59	5.99%
Total Bill on RPP (including OCEB)				**$ 238.73**			**$ 253.11**	**$ 14.39**	**6.03%**
Loss Factor (%)		4.06%			4.70%				

Bill Impacts

Customer Class: Street Lights

TOU / non-TOU: non-TOU

Connection	1,006	#
Consumption	28,100	kWh
Demand	88	kW

May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 1.1700	1,006	$ 1,177.02	$ 1.6000	1,006	$ 1,609.60	$ 432.58	36.75%
Smart Meter Rate Adder (SMIRR)	Monthly		1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.0509	88	$ 268.48	$ 4.1605	88	$ 366.12	$ 97.64	36.37%
Smart Meter Disposition Rider	Monthly			$ -		1	$ -	$ -	
GEA Rate Adder	Monthly			$ -	$ 0.0700	1	$ 0.07	$ 0.07	
Sub-Total A (excluding pass through)				$ 1,445.50			$ 1,975.79	**$ 530.29**	**36.69%**
Rate Rider for DVA (2013)	per kW	-$ 0.1545	88	-$ 13.60	-$ 0.1545	88	-$ 13.60	$ -	0.00%
Rate Rider Global Adjust (2013)	per kW	-$ 2.2660	88	-$ 199.41	-$ 2.2660	88	-$ 199.41		
Rate Rider for DVA (2014)	per kW				-$ 0.6102	88	-$ 53.70		
Rate Rider for DVA Global (2014)	per kW				-$ 1.6400	88	-$ 144.32		
Rate Rider CGAAP (2014)	per kW		2,000	$ -	-$ 0.1225	88	-$ 10.78	-$ 10.78	
Line Losses on Cost of Power		$ 0.0839	1,291.08	$ 108.32	$ 0.0839	1,494.60	$ 125.43	$ 17.11	15.79%
GEA Rate Adder	Monthly			$ -	$ 0.0700	1	$ 0.07	$ 0.07	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,340.82**			**$ 1,679.49**	**$ 338.67**	**25.26%**
RTSR - Network	per kW	$ 1.8469	88	$ 162.53	$ 1.8817	88	$ 165.59	$ 3.06	1.88%
RTSR - Line and Transformation Connection	per kW	$ 0.4265	88	$ 37.53	$ 0.4461	88	$ 39.26	$ 1.72	4.60%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,540.88**			**$ 1,884.34**	**$ 343.46**	**22.29%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	28100	$ 123.64	$ 0.0044	28100	$ 123.64	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	28100	$ 33.72	$ 0.0012	28100	$ 33.72	$ -	0.00%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0047	28100	$ 132.07	$ 0.0047	28100	$ 132.07	$ -	0.00%
TOU - Off Peak		$ 0.0670		$ -	$ 0.0670	0	$ -	$ -	
TOU - Mid Peak		$ 0.1040		$ -	$ 0.1040	0	$ -	$ -	
TOU - On Peak		$ 0.1240		$ -	$ 0.1240	0	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750	0	$ -	$ -	
Energy - Spot & Global		$ 0.1000	29241	$ 2,924.09	$ 0.1000	28100	$ 2,810.00	-$ 114.09	-3.90%
Total Bill on Spot (before Taxes)				**$ 4,754.64**			**$ 4,984.02**	**$ 229.37**	**4.82%**
HST		13%		$ 618.10	13%		$ 647.92	$ 29.82	4.82%
Total Bill (including HST)				$ 5,372.75			$ 5,631.94	$ 259.19	4.82%
Ontario Clean Energy Benefit [1]								$ -	
Total Bill on RPP (including OCEB)				**$ 5,372.75**			**$ 5,631.94**	**$ 259.19**	**4.82%**
Loss Factor (%)		4.06%			4.70%				

APPENDIX 8-D

Fort Frances Power Corporation

Track Changes of Current Bill and Proposed

Tariff of Rates and Charges,

Effective May 1, 2014

RESIDENTIAL SERVICE CLASSIFICATION		Current	Proposed
Service Charge	$	12.05	18.79
Distribution Volumetric Rate	$/kWh	0.0088	0.0137
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79	0.79
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until November 30, 2013	$	3.58	
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	3.43	
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	(0.0004)	(0.0004)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30,	$/kWh	(0.0063)	(0.0063)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0066	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0015	0.0016
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$		0.98
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kWh		0.0002
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30,	$/kWh		(0.0047)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kWh		(0.0004)
Rate Adder for GEA Direct	$		0.07
MONTHLY RATES AND CHARGES - Regulatory Component			
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25
GENERAL SERVICE LESS THAN 50 kW CLASSIFICATION		Current	Proposed
Service Charge	$	29.03	43.62
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79	0.79
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until November 30, 2013	$	13.42	
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	7.79	
Distribution Volumetric Rate	$/kWh	0.0066	0.0099
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	(0.0004)	(0.0004)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30,	$/kWh	(0.0063)	(0.0063)
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$		8.09
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0013	0.0014
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kWh		0.0003
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30, 2016 Applicable only for Non-RPP Customers	$/kWh		(0.0047)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kWh		(0.0004)
Rate Adder for GEA Direct	$		0.07
MONTHLY RATES AND CHARGES - Regulatory Component			
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.2500	0.25

GENERAL SERVICE 50 TO 4,999 KW CLASSIFICATION			
MONTHLY RATES AND CHARGES - Delivery Component		**Current**	**Proposed**
Service Charge	$	242.06	165.98
Rate Rider for Recovery of Stranded Meter Assets – effective until April 30, 2015	$		22.51
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until November 30, 2013	$	20.71	
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order	$	9.97	
Distribution Volumetric Rate	$/kW	3.5943	2.5081
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kW	(0.1671)	(0.1671)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30,	$/kW	(2.4469)	(2.4469)
Retail Transmission Rate - Network Service Rate	$/kW	2.4488	2.4949
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.5516	0.5770
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kW		0.0063
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30,	$/kW		(1.8481)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kW		(0.1381)
Rate Adder for GEA Direct	$		0.07
MONTHLY RATES AND CHARGES - Regulatory Component			
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION			
MONTHLY RATES AND CHARGES - Delivery Component		**Current**	**Proposed**
Service Charge	$	29.03	38.24
Distribution Volumetric Rate	$/kWh	0.0066	0.0087
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	(0.0004)	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0013	0.0014
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016	$/kWh		(0.0001)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018	$/kWh		(0.0004)
Rate Adder for GEA Direct	$		0.07
MONTHLY RATES AND CHARGES - Regulatory Component			
Wholesale Market Service Rate	$/kWh	0.0044	0.0044
Rural Rate Protection Charge	$/kWh	0.0012	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	0.25

STREET LIGHTING SERVICE CLASSIFICATION				
MONTHLY RATES AND CHARGES - Delivery Component			**Current**	**Proposed**
Service Charge (per connection)		$	1.17	1.60
Distribution Volumetric Rate		$/kW	3.0509	4.1605
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015		$/kW	(0.1545)	(0.1545)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30,		$/kW	(2.2660)	(2.2660)
Retail Transmission Rate - Network Service Rate		$/kW	1.8469	1.8817
Retail Transmission Rate - Line and Transformation Connection Service Rate		$/kW	0.4265	0.4461
Rate Rider for Dispostion of Deferral/Variance Account (2014) - effective until April 30. 2016		$/kW		(0.6102)
Rate Rider for Disposition of Global Adjustment Sub-Account (2014) - effective until April 30,		$/kW		(1.6400)
Rate Rider for Disposition of CGAAP Changes-1576 Effective until April 30, 2018		$/kW		(0.1225)
Rate Adder for GEA Direct		$		0.07
MONTHLY RATES AND CHARGES - Regulatory Component				
Wholesale Market Service Rate		$/kWh	0.0044	0.0044
Rural Rate Protection Charge		$/kWh	0.0012	0.0012
Standard Supply Service - Administrative Charge (if applicable)		$	0.25	0.25
MICROFIT SERVICE CLASSIFICATION				
MONTHLY RATES AND CHARGES - Delivery Component			**Current**	**Proposed**
Service Charge		$	5.40	5.40

APPENDIX 8-E

Fort Frances Power Corporation

Retail Transmission Service

Rate Work Form

PDF Version



v 4.0

RTSR Workform for Electricity Distributors (2014 Filers)

Utility Name	Fort Frances Power Corporation
Service Territory	
Assigned EB Number	EB-2013-0130
Name and Title	Joerg Ruppenstein, President and CEO
Phone Number	807-274-9291
Email Address	ffpc@fort-frances.com
Date	20-Dec-13
Last COS Re-based Year	

Note: Drop-down lists are shaded blue; Input cells are shaded green.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your COS/IRM application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.



RTSR Workform for Electricity Distributors (2014 Filers)

1. Info
2. Table of Contents
3. Rate Classes
4. RRR Data
5. UTRs and Sub-Transmission
6. Historical Wholesale
7. Current Wholesale
8. Forecast Wholesale
9. Adj Network to Current WS
10. Adj Conn. to Current WS
11. Adj Network to Forecast WS
12. Adj Conn. to Forecast WS
13. Final 2013 RTS Rates



RTSR Workform for Electricity Distributors (2014 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	$ 0.0066	$ 0.0015
General Service Less Than 50 kW	kWh	$ 0.0060	$ 0.0013
General Service 50 to 4,999 kW	kW	$ 2.4488	$ 0.5516
Unmetered Scattered Load	kWh	$ 0.0060	$ 0.0013
Street Lighting	kW	$ 1.8469	$ 0.4265
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			



RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	**kWh**	37,048,424		1.0406		38,552,590	-
General Service Less Than 50 kW	**kWh**	14,513,641		1.0406		15,102,895	-
General Service 50 to 4,999 kW	**kW**	23,619,302	58,302		**55.53%**	23,619,302	58,302
Unmetered Scattered Load	**kWh**	62,628		1.0406		65,171	-
Street Lighting	**kW**	366,947	1,055		**47.67%**	366,947	1,055



RTSR Workform for Electricity Distributors (2014 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.57	$ 3.63	$ 3.63
Line Connection Service Rate	kW	$ 0.80	$ 0.75	$ 0.75
Transformation Connection Service Rate	kW	$ 1.86	$ 1.85	$ 1.85

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 3.18	$ 3.18
Line Connection Service Rate	kW	$ 0.64	$ 0.70	$ 0.70
Transformation Connection Service Rate	kW	$ 1.50	$ 1.63	$ 1.63
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.33	$ 2.33

If needed , add extra host here (I)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed , add extra host here (II)	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

Hydro One Sub-Transmission Rate Rider 9A	Unit	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ -	$ 0.1465	$ 0.1465

RSVA Transmission connection – 4716 – which affects 1586	kW	**$**	**-**	**$**	**0.0667**	**$**	**0.0667**
RSVA LV – 4750 – which affects 1550	kW	**$**	**-**	**$**	**0.0475**	**$**	**0.0475**
RARA 1 – 2252 – which affects 1590	kW	**$**	**-**	**$**	**0.0419**	**$**	**0.0419**
RARA 1 – 2252 – which affects 1590 (2008)	kW	**$**	**-**	**-$**	**0.0270**	**-$**	**0.0270**
RARA 1 – 2252 – which affects 1590 (2009)	kW	**$**	**-**	**-$**	**0.0006**	**-$**	**0.0006**
Hydro One Sub-Transmission Rate Rider 9A	kW	**$**	**-**	**$**	**0.2750**	**$**	**0.2750**

		Historical 2012	Current 2013	Forecast 2014
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			



RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	13,963	$3.57	$ 49,848	16,288	$0.80	$ 13,030		$0.00		$ 13,030
February	13,527	$3.57	$ 48,291	14,508	$0.80	$ 11,606		$0.00		$ 11,606
March	12,412	$3.57	$ 44,311	12,826	$0.80	$ 10,261		$0.00		$ 10,261
April	9,647	$3.57	$ 34,440	10,900	$0.80	$ 8,720		$0.00		$ 8,720
May	8,273	$3.57	$ 29,535	9,733	$0.80	$ 7,786		$0.00		$ 7,786
June	10,316	$3.57	$ 36,828	12,137	$0.80	$ 9,710		$0.00		$ 9,710
July	11,099	$3.57	$ 39,623	12,749	$0.80	$ 10,199		$0.00		$ 10,199
August	10,978	$3.57	$ 39,191	12,915	$0.80	$ 10,332		$0.00		$ 10,332
September	9,016	$3.57	$ 32,187	10,607	$0.80	$ 8,486		$0.00		$ 8,486
October	10,759	$3.57	$ 38,410	11,296	$0.80	$ 9,037		$0.00		$ 9,037
November	13,583	$3.57	$ 48,491	14,169	$0.80	$ 11,335		$0.00		$ 11,335
December	14,002	$3.57	$ 49,987	15,506	$0.80	$ 12,405		$0.00		$ 12,405
Total	137,575	$ 3.57	$ 491,142	153,634	$ 0.80	$ 122,907	-	$ -	$ -	$ 122,907

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -



RTSR Workform for Electricity Distributors (2014 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

May		$0.00			$0.00			$0.00			$	-	$	-
June		$0.00			$0.00			$0.00			$	-	$	-
July		$0.00			$0.00			$0.00			$	-	$	-
August		$0.00			$0.00			$0.00			$	-	$	-
September		$0.00			$0.00			$0.00			$	-	$	-
October		$0.00			$0.00			$0.00			$	-	$	-
November		$0.00			$0.00			$0.00			$	-	$	-
December		$0.00			$0.00			$0.00			$	-	$	-
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$	-	$ -	$	-

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	13,963	$3.57	$ 49,848	16,288	$0.80	$ 13,030	-	$0.00	$ -	$ 13,030
February	13,527	$3.57	$ 48,291	14,508	$0.80	$ 11,606	-	$0.00	$ -	$ 11,606
March	12,412	$3.57	$ 44,311	12,826	$0.80	$ 10,261	-	$0.00	$ -	$ 10,261
April	9,647	$3.57	$ 34,440	10,900	$0.80	$ 8,720	-	$0.00	$ -	$ 8,720
May	8,273	$3.57	$ 29,535	9,733	$0.80	$ 7,786	-	$0.00	$ -	$ 7,786
June	10,316	$3.57	$ 36,828	12,137	$0.80	$ 9,710	-	$0.00	$ -	$ 9,710
July	11,099	$3.57	$ 39,623	12,749	$0.80	$ 10,199	-	$0.00	$ -	$ 10,199
August	10,978	$3.57	$ 39,191	12,915	$0.80	$ 10,332	-	$0.00	$ -	$ 10,332
September	9,016	$3.57	$ 32,187	10,607	$0.80	$ 8,486	-	$0.00	$ -	$ 8,486
October	10,759	$3.57	$ 38,410	11,296	$0.80	$ 9,037	-	$0.00	$ -	$ 9,037
November	13,583	$3.57	$ 48,491	14,169	$0.80	$ 11,335	-	$0.00	$ -	$ 11,335
December	14,002	$3.57	$ 49,987	15,506	$0.80	$ 12,405	-	$0.00	$ -	$ 12,405
Total	137,575	$ 3.57	$ 491,142	153,634	$ 0.80	$ 122,907	-	$ -	$ -	$ 122,907



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	13,963	$ 3.6300	$ 50,686	16,288	$ 0.7500	$ 12,216	-	$ 1.8500	$ -	$ 12,216
February	13,527	$ 3.6300	$ 49,103	14,508	$ 0.7500	$ 10,881	-	$ 1.8500	$ -	$ 10,881
March	12,412	$ 3.6300	$ 45,056	12,826	$ 0.7500	$ 9,620	-	$ 1.8500	$ -	$ 9,620
April	9,647	$ 3.6300	$ 35,019	10,900	$ 0.7500	$ 8,175	-	$ 1.8500	$ -	$ 8,175
May	8,273	$ 3.6300	$ 30,031	9,733	$ 0.7500	$ 7,300	-	$ 1.8500	$ -	$ 7,300
June	10,316	$ 3.6300	$ 37,447	12,137	$ 0.7500	$ 9,103	-	$ 1.8500	$ -	$ 9,103
July	11,099	$ 3.6300	$ 40,289	12,749	$ 0.7500	$ 9,562	-	$ 1.8500	$ -	$ 9,562
August	10,978	$ 3.6300	$ 39,850	12,915	$ 0.7500	$ 9,686	-	$ 1.8500	$ -	$ 9,686
September	9,016	$ 3.6300	$ 32,728	10,607	$ 0.7500	$ 7,955	-	$ 1.8500	$ -	$ 7,955
October	10,759	$ 3.6300	$ 39,055	11,296	$ 0.7500	$ 8,472	-	$ 1.8500	$ -	$ 8,472
November	13,583	$ 3.6300	$ 49,306	14,169	$ 0.7500	$ 10,627	-	$ 1.8500	$ -	$ 10,627
December	14,002	$ 3.6300	$ 50,827	15,506	$ 0.7500	$ 11,630	-	$ 1.8500	$ -	$ 11,630
Total	137,575	$ 3.63	$ 499,397	153,634	$ 0.75	$ 115,226	-	$ -	$ -	$ 115,226

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
February	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
March	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
April	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
May	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
June	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
July	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
August	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
September	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
October	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
November	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
December	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -


RTSR Workform for
Electricity Distributors
(2014 Filers)

The purpose of this sheet is to calculate the expected billing when current 2013 Uniform Transmission Rates are applied against historical 2012 transmission units.

December	-	$	-	$	-	-	$	-	$	-	-	$	-	$	-	$	-
Total	-	$	-	$	-	-	$	-	$	-	-	$	-	$	-	$	-

Total	**Network**			**Line Connection**			**Transformation Connection**			**Total Line**
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	13,963	$3.63	$ 50,686	16,288	$0.75	$ 12,216	-	$0.00	$ -	$ 12,216
February	13,527	$3.63	$ 49,103	14,508	$0.75	$ 10,881	-	$0.00	$ -	$ 10,881
March	12,412	$3.63	$ 45,056	12,826	$0.75	$ 9,620	-	$0.00	$ -	$ 9,620
April	9,647	$3.63	$ 35,019	10,900	$0.75	$ 8,175	-	$0.00	$ -	$ 8,175
May	8,273	$3.63	$ 30,031	9,733	$0.75	$ 7,300	-	$0.00	$ -	$ 7,300
June	10,316	$3.63	$ 37,447	12,137	$0.75	$ 9,103	-	$0.00	$ -	$ 9,103
July	11,099	$3.63	$ 40,289	12,749	$0.75	$ 9,562	-	$0.00	$ -	$ 9,562
August	10,978	$3.63	$ 39,850	12,915	$0.75	$ 9,686	-	$0.00	$ -	$ 9,686
September	9,016	$3.63	$ 32,728	10,607	$0.75	$ 7,955	-	$0.00	$ -	$ 7,955
October	10,759	$3.63	$ 39,055	11,296	$0.75	$ 8,472	-	$0.00	$ -	$ 8,472
November	13,583	$3.63	$ 49,306	14,169	$0.75	$ 10,627	-	$0.00	$ -	$ 10,627
December	14,002	$3.63	$ 50,827	15,506	$0.75	$ 11,630	-	$0.00	$ -	$ 11,630
Total	137,575	$ 3.63	$ 499,397	153,634	$ 0.75	$ 115,226	-	$ -	$ -	$ 115,226



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	13,963	$ 3.6300	$ 50,686	16,288	$ 0.7500	$ 12,216	-	$ 1.8500	$ -	$ 12,216
February	13,527	$ 3.6300	$ 49,103	14,508	$ 0.7500	$ 10,881	-	$ 1.8500	$ -	$ 10,881
March	12,412	$ 3.6300	$ 45,056	12,826	$ 0.7500	$ 9,620	-	$ 1.8500	$ -	$ 9,620
April	9,647	$ 3.6300	$ 35,019	10,900	$ 0.7500	$ 8,175	-	$ 1.8500	$ -	$ 8,175
May	8,273	$ 3.6300	$ 30,031	9,733	$ 0.7500	$ 7,300	-	$ 1.8500	$ -	$ 7,300
June	10,316	$ 3.6300	$ 37,447	12,137	$ 0.7500	$ 9,103	-	$ 1.8500	$ -	$ 9,103
July	11,099	$ 3.6300	$ 40,289	12,749	$ 0.7500	$ 9,562	-	$ 1.8500	$ -	$ 9,562
August	10,978	$ 3.6300	$ 39,850	12,915	$ 0.7500	$ 9,686	-	$ 1.8500	$ -	$ 9,686
September	9,016	$ 3.6300	$ 32,728	10,607	$ 0.7500	$ 7,955	-	$ 1.8500	$ -	$ 7,955
October	10,759	$ 3.6300	$ 39,055	11,296	$ 0.7500	$ 8,472	-	$ 1.8500	$ -	$ 8,472
November	13,583	$ 3.6300	$ 49,306	14,169	$ 0.7500	$ 10,627	-	$ 1.8500	$ -	$ 10,627
December	14,002	$ 3.6300	$ 50,827	15,506	$ 0.7500	$ 11,630	-	$ 1.8500	$ -	$ 11,630
Total	137,575	$ 3.63	$ 499,397	153,634	$ 0.75	$ 115,226	-	$ -	$ -	$ 115,226

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
February	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
March	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
April	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
May	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
June	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
July	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
August	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
September	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
October	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
November	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
December	-	$ 3.3265	$ -	-	$ 0.7667	$ -	-	$ 1.6300	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2014 Uniform Transmission Rates are applied against historical 2012 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	13,963	$ 3.63	$ 50,686	16,288	$ 0.75	$ 12,216	-	$ -	$ -	$ 12,216
February	13,527	$ 3.63	$ 49,103	14,508	$ 0.75	$ 10,881	-	$ -	$ -	$ 10,881
March	12,412	$ 3.63	$ 45,056	12,826	$ 0.75	$ 9,620	-	$ -	$ -	$ 9,620
April	9,647	$ 3.63	$ 35,019	10,900	$ 0.75	$ 8,175	-	$ -	$ -	$ 8,175
May	8,273	$ 3.63	$ 30,031	9,733	$ 0.75	$ 7,300	-	$ -	$ -	$ 7,300
June	10,316	$ 3.63	$ 37,447	12,137	$ 0.75	$ 9,103	-	$ -	$ -	$ 9,103
July	11,099	$ 3.63	$ 40,289	12,749	$ 0.75	$ 9,562	-	$ -	$ -	$ 9,562
August	10,978	$ 3.63	$ 39,850	12,915	$ 0.75	$ 9,686	-	$ -	$ -	$ 9,686
September	9,016	$ 3.63	$ 32,728	10,607	$ 0.75	$ 7,955	-	$ -	$ -	$ 7,955
October	10,759	$ 3.63	$ 39,055	11,296	$ 0.75	$ 8,472	-	$ -	$ -	$ 8,472
November	13,583	$ 3.63	$ 49,306	14,169	$ 0.75	$ 10,627	-	$ -	$ -	$ 10,627
December	14,002	$ 3.63	$ 50,827	15,506	$ 0.75	$ 11,630	-	$ -	$ -	$ 11,630
Total	137,575	$ 3.63	$ 499,397	153,634	$ 0.75	$ 115,226	-	$ -	$ -	$ 115,226



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0066	38,552,590	-	$ 254,447	51.9%	$ 259,235	$0.0067
General Service Less Than 50 kW	kWh	$ 0.0060	15,102,895	-	$ 90,617	18.5%	$ 92,322	$0.0061
General Service 50 to 4,999 kW	kW	$ 2.4488	23,619,302	58,302	$ 142,770	29.1%	$ 145,456	$2.4949
Unmetered Scattered Load	kWh	$ 0.0060	65,171	-	$ 391	0.1%	$ 398	$0.0061
Street Lighting	kW	$ 1.8469	366,947	1,055	$ 1,948	0.4%	$ 1,985	$1.8817
					$ 490,174			



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0015	38,552,590	-	$ 57,829	52.5%	$ 60,490	$0.0016
General Service Less Than 50 kW	kWh	$ 0.0013	15,102,895	-	$ 19,634	17.8%	$ 20,537	$0.0014
General Service 50 to 4,999 kW	kW	$ 0.5516	23,619,302	58,302	$ 32,159	29.2%	$ 33,639	$0.5770
Unmetered Scattered Load	kWh	$ 0.0013	65,171	-	$ 85	0.1%	$ 89	$0.0014
Street Lighting	kW	$ 0.4265	366,947	1,055	$ 450	0.4%	$ 471	$0.4461
					$ 110,157			



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$0.0067	38,552,590	-	259,234.89	51.9%	$ 259,235	$0.0067
General Service Less Than 50 kW	kWh	$0.0061	15,102,895	-	$ 92,322	18.5%	$ 92,322	$0.0061
General Service 50 to 4,999 kW	kW	$2.4949	23,619,302	58,302	$ 145,456	29.1%	$ 145,456	$2.4949
Unmetered Scattered Load	kWh	$0.0061	65,171	-	$ 398	0.1%	$ 398	$0.0061
Street Lighting	kW	$1.8817	366,947	1,055	$ 1,985	0.4%	$ 1,985	$1.8817
					$ 499,397			



RTSR Workform for Electricity Distributors (2014 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0016	38,552,590	-	$ 60,490	52.5%	$ 60,490	$ 0.0016
General Service Less Than 50 kW	kWh	$ 0.0014	15,102,895	-	$ 20,537	17.8%	$ 20,537	$ 0.0014
General Service 50 to 4,999 kW	kW	$ 0.5770	23,619,302	58,302	$ 33,639	29.2%	$ 33,639	$ 0.5770
Unmetered Scattered Load	kWh	$ 0.0014	65,171	-	$ 89	0.1%	$ 89	$ 0.0014
Street Lighting	kW	$ 0.4461	366,947	1,055	$ 471	0.4%	$ 471	$ 0.4461
					$ 115,226			



RTSR Workform for Electricity Distributors (2014 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I.
Please note that the rate descriptions for the RTSRs are transfered automatically from Sheet 4 to Sheet 11, Column A.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0067	$ 0.0016
General Service Less Than 50 kW	kWh	$ 0.0061	$ 0.0014
General Service 50 to 4,999 kW	kW	$ 2.4949	$ 0.5770
Unmetered Scattered Load	kWh	$ 0.0061	$ 0.0014
Street Lighting	kW	$ 1.8817	$ 0.4461



Filing Number: EB-2013-0130
Filed: December 20, 2013

EXHIBIT NINE

DEFERRAL AND VARIANCE ACCOUNTS

1

Exhibit	Tab	Schedule	Appendix	Contents
9 – Deferral and Variance Accounts				
				Overview
		2		Previous Deferral/Variance Account Disposition
	2	1		Status of Deferral and Variance Accounts
		2		Deferral and Variance Account Balances
	3	1		Accounts Requested for Disposition by way of a DVA Rate Rider
		2		Methods of Disposition
		3		Stranded Meter Rate Rider
		4		Green Energy Act
		5		LRAM Recovery
		6		Account 1576 Disposition
				Appendix
			A	2014 Regulatory Asset Continuity Schedule
			B	2011 OPA Final Evaluation Report
			C	2012 OPA Final Evaluation Report

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3

DEFERRAL AND VARIANCE ACCOUNTS: OVERVIEW

The information contained in this exhibit includes the status and description of Fort Frances Power Corporation's (FFPC) deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

FFPC has completed the required DVA continuity schedule and account balances match the trial balance in the RRR filing and the audited financial statement with the exception of the one account, USoA 1595, Sub-Account for Shared Tax Savings. The accounting entry of -$3,098.34 was completed in 2013 and omitted from the 2012 audited financial statements and RRR reporting.

PREVIOUS DEFERRAL AND VARIANCE ACCOUNT DISPOSITION

2013 IRM Approval and Board Directive

On April 4, 2013, the Ontario Energy Board's Decision and Order EB-2012-0083 approved a two year disposition for FFPC's audited December 31, 2011 Group 1 deferral and variance account credit balances in the amount of -$380,940, which includes a credit balance of -$311,986 in the 1588 global adjustment sub-account.

In 2013, the approved balances were transferred to a sub-account of 1595 in accordance with the Decision and Order EB-2012-0083. The corresponding rate riders for the refund of the approved balances over a two year period are effective until April 30, 2015. Table 9.1 below summarizes the 2013 IRM approved Group 1 accounts and amounts for disposition.

Table 9.1: 2013 IRM Approved Group 1 Amounts for Disposition

Table 9.1- EB-2012-0083 Approved Group One Accounts for Disposition				
Account Description	Account	December 31, 2011 Principal Balance	December 31, 2011 Interest Balance	Total Claim
		A	B	C
RSVA - Wholesale Market Service Charge	1580	-$76,144	-$636	-$76,780
RSVA - Retail Transmission Network Charge	1584	$17,336	$508	$17,844
RSVA - Retail Transmission Connection Charge	1586	-$3,146	$1,846	-$1,300
RSVA - Power (excluding Global Adjustment)	1588	-$9,401	$513	-$8,888
Recovery of Regulatory Asset Balances	1590		$170	$170
Total Excluding Global Adjustment Sub-Account		**-$71,355**	**$2,401**	**-$68,954**
RSVA - Global Adjustment	1589	-$305,824	-$6,162	-$311,986
Total Dispostion of Regulatory Balances		**-$377,179**	**-$3,761**	**-$380,940**

2012 IRM Approval and Board Directive

On March 7, 2012, the Ontario Energy Board's Decision and Order EB-2011-0146 approved a one year disposition for FFPC's audited December 31, 2010 Group 1 deferral and variance account credit balances, excluding the Global Adjustment Sub-Account balance, in the amount of -$389,236, and approved a one year disposition for FFPC's December 31, 2010 Group 1

Global Adjustment Sub-Account in the amount of the credit balance of -$37,391 on a prospective basis to all non-RPP customers.

In 2012, the approved balances were transferred to a sub-account of 1595 in accordance with the Decision and Order EB-2011-0146. The corresponding rate riders for the approved Group 1 deferral and variance account balances including the Global Adjustment Sub-Account balances are effective until April 30, 2013. Table 9.1.2 below summarizes the 2012 IRM approved Group 1 accounts and amounts for disposition.

Table 9.2: 2012 IRM Approved Group 1 Amounts for Disposition

Table 9.2 -IRM EB-2011-0146 Approved Group One Accounts for Disposition				
Account Description	Account	December 31, 2010 Principal Balance	December 31, 2010 Interest Balance	Total Claim
		A	B	C
RSVA - Wholesale Market Service Charge	1580	-$280,612	$27,302	-$253,310
RSVA - Retail Transmission Network Charge	1584	$12,889	-$12,705	$184
RSVA - Retail Transmission Connection Charge	1586	-$404,911	-$128,449	-$533,360
RSVA - Power (excluding Global Adjustment)	1588	$436,070	$36,575	$472,645
Recovery of Regulatory Asset Balances	1590	-$34,526	-$3,478	-$38,004
Total Excluding Global Adjustment Sub-Account		**-$271,091**	**-$80,754**	**-$351,845**
RSVA - Global Adjustment	1588 sub	-$35,115	-$2,276	-$37,391
Total Dispostion of Regulatory Balances		**-$306,206**	**-$83,030**	**-$389,236**

Review and Disposition of Account 1521 – Special Purpose Charge

On March 7, 2012, the Ontario Energy Board's Decision and Order EB-2011-0146 approved, on a final basis, the disposition of a balance of $2,280 in Account #1521. In 2012, the approved balance was transferred to a subaccount of 1595 in accordance with the Decision and Order EB-2011-0146.

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS:

This Schedule contains the status of Deferral and Variance Accounts ("DVAs") currently used by FFPC. The audited Dec 31, 2012 DVAs account balances include the audited balances for Dec 31, 2011 which will need to be adjusted for each time from the 2013 IRM approved disposition amount. The balances as at December 31, 2012 and the proposed recovery amounts are summarized in Table 9.3, following the descriptions of each account:

GROUP 1 ACCOUNTS

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by the IESO and Hydro One based on the settlement invoices for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. FFPC uses the accrual method in accordance with the Board's directive. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2014, FFPC is requesting disposition of the December 31, 2012 audited balance, less the 2013 IRM approved disposition amounts plus the forecasted interest through April 30, 2015 for account 1580. The requested amount is a credit balance of -$99,297.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by Hydro One, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Retail Transmission Network Charge. FFPC uses the accrual method in accordance with the Board's directive. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2014, FFPC is requesting disposition of the December 31, 2012 audited balance, less the 2013 IRM approved disposition amounts plus the forecasted interest through April 30, 2015 for account 1584. The requested amount is a debit balance of $1,588.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by Hydro One, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge. FFPC uses the accrual method in accordance with the Board's directive. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2014, FFPC is requesting disposition of the December 31, 2012 audited balance, less the 2013 IRM approved disposition amounts plus the forecasted interest through April 30, 2014 for account 1586. The requested amount is a credit balance of -$ 156.

1588 Retail Settlement Variance Account – Power (Excluding Global Adjustment)

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to FFPC using the settlement invoices from the Independent Electricity System Operator (IESO) and Hydro One. FFPC uses the accrual method in accordance with the Board's directive. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2014, FFPC is requesting disposition of the December 31, 2012 audited balance, less the 2013 IRM approved disposition amounts plus the forecasted interest through April 30, 2015 for account 1588 - Power. The requested amount is a debit balance of $56,078.

1589 Retail Settlement Variance Account - Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to FFPC using the settlement invoices from the IESO. FFPC pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions are part of the settlement with IESO. FFPC uses the accrual method in accordance with the Board's directive. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2014, FFPC is requesting disposition of the December 31, 2012 audited balance, less the 2013 IRM approved disposition amounts plus the forecasted interest through April 30, 2015 for account 1589 Global Adjustment through a separate non-RPP rate rider. The requested amount is a credit balance of -$224,583.

1595 Disposition and Recovery of Regulatory Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery.

Sub-Account 2012 for EB-2011-0146: In accordance with the OEB EB-2011-0146 Decision and Order for FFPC's 2012 IRM, the December 31, 2010 credit balance of -$386,956., including the global adjustment sub-account and the interest forecast to April 30, 2012 was transferred to a sub-account of 1595 in April 2012. As of April 30, 2013 the disposition period for Group 1 balances, including the global adjustment, was completed, however, FFPC is not requesting disposition of the residual balance in this sub-account, as the balance has not been audited.

Sub-Account 2013 for EB-2012-0083: In accordance with the OEB EB-2012-0083 Decision and Order for FFPC's 2013 IRM, the December 31, 2011 credit balance of $-380,940., including the global adjustment sub-account and the interest forecast to April 30, 2013 was transferred to a sub-account of 1595 in May 2013. As of April 30, 2013 the disposition period for Group 1 balances, including the global adjustment, was completed, however, FFPC is not requesting disposition of the residual balance in this sub-account, as the recovery period is not complete until April 30, 2014.

Sub-Account for Shared Tax Savings: In accordance with the OEB EB-2011-0146 Decision and Order for FFPC's 2012 IRM and OEB EB-2012-0083 Decision and Order for FFPC's 2013 IRM, FFPC was instructed to record the tax sharing refund of -$3,072 (2012) and for a total credit balance of -$3,159 including interest. FFPC is seeking disposition of this account in this application.

Table 9.3 below details the Group 1 disposition balances:

Proposed Group One Accounts for Disposition								
Account Description	Account	December 31, 2012 Principal Balance	December 31, 2012 Interest Balance	Audited Financial Statement Balances December 31, 2012	Principal Disposition during 2013 as instructed by the Board - EB-2012-0083	Interest Disposition during 2013 as instructed by the Board - EB-2012-0083	Projected Interest on December 31, 2012 balances for Jan 1, 2013 to April 30,2014	Total
Group 1 Accounts		A	B	Account Balance				C
RSVA - Wholesale Market Service Charge	1580	-$171,483	-$2,685	-$174,168	$76,144	$636	-$1,909	-$99,297
RSVA - Retail Transmission Network Charge	1584	$18,522	$878	$19,401	-$17,336	-$508	$31	$1,588
RSVA - Retail Transmission Connection Charge	1586	-$755	-$698	-$1,453	$3,146	-$1,846	-$3	-$156
RSVA - Power (excluding Global Adjustment)	1588	$39,899	$6,213	$46,112	$9,401	-$513	$1,078	$56,078
RSVA - Global Adjustment	1589	-$525,543	-$6,710	-$532,253	$305,824	$6,162	-$4,317	-$224,584
Recovery of Regulatory Asset Balances	1590	$170		$170	-$170			$0
Sub-Total (Including Account 1589 - Global Adjustment)		**-$639,190**	**-$3,001**	-$642,191	$377,009	$3,931	**-$5,120**	**-$266,371**
Sub-Total (Excluding Account 1589 - Global Adjustment)		**-$113,647**	**$3,709**	-$109,938			**-$803**	**-$110,741**

GROUP 2 ACCOUNTS

1508 Other Regulatory Assets – Sub-account OEB Cost Assessment

This account includes amounts to record the variance between the OEB annual cost assessment fees previously captured in 2001 rates and the amounts charged in 2004 until April 2006. This account balance was verified in a DVA Group 2 Audit by Board staff completed in March 2012.

FFPC has not rebased since the 2006 EDR and has not previously addressed the disposition of this account. FFPC is seeking disposition of the account balance of December 31, 2012 of $8,288 plus the forecasted interest through April 30, 2014 for a total of $8,451.

1508 Other Regulatory Assets – Sub-account IFRS Transition Costs

This account includes amounts paid for one-time incremental International Financial Reporting Standards (IFRS) transition costs not included in rates, until the transition to IFRS has commenced. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

FFPC has established Account 1508 – sub account – Deferred IFRS Transition Costs in accordance with the Board requirements. In the Board's Accounting Procedures Handbook Frequently Asked Questions October 2009 ("APH-FAQ October 2009"), the Board permitted the deferral of one-time administrative costs caused by the transition of accounting policies, procedures, systems, and processes to International Financial Reporting Standards ("IFRS") in this sub-account. Also in the Board's Accounting Procedures Handbook Frequently Asked Questions October 2009 ("APH-FAQ October 2009"), the Board permitted interest carrying charges to be calculated on the monthly opening principal balance of this sub-account at the Board's prescribed interest rates. Based on this guidance, FFPC commenced to defer professional accounting fees, incremental salaries, wages, and benefits of staff attributable to the transition to IFRS, staff training costs solely related to IFRS and carrying charges solely related to these items.

FFPC is seeking disposition of the December 31, 2012 audited balance of $27,183 for one-time administrative costs in this Application which includes carrying charges of

$851 up to April 30, 2014. These costs represent only professional accounting fees paid to BDO Dunwoody to assist with the transition.

All of the incremental IFRS transition costs relate to third party consultants that were used to help implement IFRS. This includes consultancy costs from BDO to assist with IFRS implementation within FFPC. BDO was hired to assist with the transitional analysis, analysis regarding fixed assets componentization, useful lives, and overheads. This work was completed with the assistance of FFPC staff and in consultation with external auditors by the end of December 31, 2012. These costs would not be incurred if FFPC was not required to transition to IFRS. There were no costs included in this account for incremental labour costs of staff to work on the IFRS project and training. These costs may be incurred in the future as FFPC completes its transition to IFRS.

FFPC confirms these costs are not already approved and included for recovery in distribution rates. FFPC also confirms the balance requested for disposition does not include ongoing IFRS compliance costs, impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income, costs related to system upgrades where IFRS was not the major reason for conversion, and costs that are capital in nature.

CONTINUATION OF IFRS TRANSITION COST SUB – ACCOUNT 1508

In 2010, the OEB approved 1508 – Other Regulatory Assets – Sub Account – Deferred IFRS Transition Costs, to record incremental costs incurred in relation to the transition to International Financial Reporting Standards (IFRS). The July 28, 2009 Report of the Board EB-2008-0408, Transition to International Financial Reporting Standards, stated "As required by the Canadian Accounting Standards Board, Canadian Generally

Accepted Accounting Principles (CGAAP) for publically accountable enterprises will transition to IFRS effective January 1, 2011". It was expected by the Board that incremental transition costs incurred after the January 1, 2011 were expected to be minimal.

On July 20 and 22, 2010, the International Accounting Standards Board (IASB) held deliberations on rate-regulated activities and made the decision to continue with its project addressing the recognition, measurement and disclosure of regulatory assets and liabilities, and not to develop transitional guidance for use by first-time adopters. The Canadian Accounting Standards Board (AcSB) discussed these developments and decided to amend the CICA Handbook to require that qualifying entities with rate-regulated activities adopt IFRS for the first time no later than fiscal periods beginning on or after January 1, 2012. Entities electing to defer the first time adoption of IFRS must also disclose that fact.

On March 20, 2012, the Canadian Accounting Standards Board ("AcSB") announced on March 30, 2012 that it would again extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate regulated activities by one year to January 1, 2013. The deferral of the mandatory changeover date for an additional year would permit the AcSB to consider the actions it might take should the IASB add to its agenda a project on the effects of rate regulation.

FFPC is deferring implement IFRS until January 1, 2015, or until pending future decisions and direction from the IASB, the AcSB, and the OEB. Because of this, FFPC will continue to incur costs associated with the transition to IFRS. FFPC therefore requests the continuation of the 1508 – Other Regulatory Assets – Sub Account – Deferred IFRS Transition Costs for disposition in a future rate proceeding.

FFPC has incurred additional professional accounting fees and salaries, wages and benefits expenses in 2013. Consequently, FFPC is requesting disposition of the 2012 audited balance only and respectfully requests continuation of the IFRS Transition Cost sub-account 1508 for disposition in a future rate proceeding.

1518 Retail Settlement Variance Account – Retail

FFPC does not track to recover the net differences between the revenues recovered from Retailer Service Agreements and Billing options and the cost of managing the retailer contracts.

FFPC has approximately 80 retailer enrolled customers, which is 2% of our customer base number and our retailer enrollment is decreasing each year.

1531 Renewable Generation Connection Capital Deferral Account

FFPC will discuss the disposition of the account further in this exhibit.

1548 Retail Settlement Variance Account – Service Transaction Request

This account is used to recover the net differences between the revenues recovered from Service Transaction Requests and the incremental costs of providing these services. FFPC does not track these costs due to our low retailer enrollment and associated costs.

1555 Smart Meter Capital and Recoveries – Sub-Accounts

Amounts recorded in this account include the revenues from smart meter adders approved by the Board for smart meters and related capital costs incurred by FFPC. On

November 1, 2012 the Ontario Energy Board's Decision and Order EB-2012-0327 approved the disposition of this account on a final basis. The corresponding rate rider was effective until November 30, 2013. In 2012, the approved balance was transferred to the corresponding revenue and capital accounts. FFPC will be requested the disposition of the Stranded Meter Assets further in this application.

1556 Smart Meter OM&A Variance Account

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. November 1, 2012, the Ontario Energy Board's Decision and Order EB-2012-0327 approved the disposition of this account on a final basis. The corresponding rate rider is effective until FFPC's next cost of service application, effective April 30, 2014. In 2012, the approved balances were transferred to the corresponding OM&A accounts. Within the application, FFPC was directed to deal this the disposition of stranded meter assets in its next rebasing application and to continue the amortization of the stranded meter until disposition.
FFPC has requested the disposition of the stranded meters in a separate rate rider as detailed below.

1562 Deferred Payments in Lieu of Taxes

This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2006.

In accordance with the Decision and Order EB-2011-0146 dated April 19, 2012, FFPC was ordered to transfer the balance of Account 1562 to the principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements of Article 220, Account Descriptions, of the Accounting Procedures Handbook for the Electricity

Distributors. FFPC has transferred a credit balance of $25,203 and an interest credit balance of $6,679 to Account 1595 for disposition to customers from May 1, 2012 to April 30, 2013 on a final basis. FFPC is seeking to discontinue the tracking of this account as all Board requirements have been met.

1568 LRAM Variance Account

This account includes the lost revenue adjustment mechanism ("LRAM") variances in relation to the conservation and demand management ("CDM") programs or activities undertaken by FFPC in accordance with Board- prescribed requirements. FFPC is requesting disposition of a debit amount of $22,523. More detail in regards to the LRAM claim can be found in the LRAM Recovery section below.

1576 Accounting Changes Under CGAAP

This account is used to record difference arising as a result of accounting policy changes for depreciation expenses and capitalization policies effective January 1, 2013. The "Kinectrics Report, (EB-2010-0178)" dated July 8, 2010 provided the necessary framework that FFPC used to underpin FFPC's Asset Management Policy that determined FFPC's "Expected Useful Life" determinants. Disposition of this account can be found in the 'Accounting Changes Under CGAAP' section below.

1582 RSVA- One Time Charges

FFPC is seeking the disposition of the residual variance account balance of $6,891 for recovery. The account includes charges totaling $4,256 and carrying charges of $2,635.

1592 PILs and Tax Variance for 2006 and Subsequent Years; and

This account is used to record the tax impact of differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model, differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published by federal or provincial tax authorities, or any differences in 2006 PILs that result in changes in a distributor's "opening" 2006 balances for tax accounts due to changes arising from a tax re-assessment for specific time periods.

FFPC did not track the perceived tax savings variance as FFPC is a 'not-for-profit' LDC and, within this profit structure, has elected to seek a zero rate of return. All savings realized through tax changes or efficiencies are wholly returned to our customers through our rate minimization cost structure. FFPC sought guidance from our auditor group that recommended the tracking and subsequent disposal would create an extraneous regulatory accounting burden that would be borne by the customer. Our auditors also stated that as FFPC has an accumulated deficit of $513,338, any additional regulatory liability would be a further pass-through cost to our customers, again negating any perceived benefit.

FFPC is requesting an exception from recording any tax variances in the account 1592-PILs and Tax Variance for 2006 and Subsequent Years due to our 'not-for-profit' status and our rate minimization strategy.

1592 PILs and Tax Variance for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITC's)

Effective on July 1, 2010, distributors were to record the incremental ITC they received on distribution revenue requirement items that were previously subject to PST and become subject to HST. 50 percent of the confirmed balance in this account shall be returnable to the ratepayers.

FFPC did not track the perceived tax savings variance as FFPC is a 'not-for-profit' LDC as any savings realized would not advantage FFPC. FFPC consulted our independent auditors to review this standpoint. The auditor's position reinforced that an Input Tax Credit (ITC) variance account would result in a calculated regulatory liability and an increased administrative cost burden for disposition which would subsequently be recovered in rates. This regulatory liability would result in a pass-through of burdened disposition costs to the customer. As FFPC elects a zero rate of return and operates under a rate minimization strategy, where all savings through legislation, regulatory and found efficiencies are continually passed on to the customer, the implement of this liability would increase rates rather than decrease rates.

Further to this point, FFPC's Customer Satisfaction survey stated that 6.4% of customers sought an improvement in 'rate reduction'. It is FFPC's belief that this request is acting on the best interest of our customers and is seeking an exemption in the tracking of this variance from the July 1, 2010 introduction of HST and all future variance tracking.

Further to that point and, as outlined previously, FFPC is an accumulated deficit position and any further variance disposition would result in a further financial burden that if not recovered in rates would undermine future capital projects and customer services provided.

Table 9.3 - Group 2 Disposition Balances

Table 9.9 - Group Two Accounts for Disposition						
Account Description	Account	December 31, 2012 Principal Balance	December 31, 2012 Interest Balance	Audited Financial Statement Balances December 31, 2012	Projected Interest on December 31, 2012 balances for Jan 1, 2013 to April 30,2014	Total
Group 2 Accounts						
Other-Reg Assets - Sub-Account - OEB Cost Assessments	1508	**$6,914**	**$1,374**	$8,288	$162	$8,450
Other-Reg Assets - Sub-Account - IFRS Transition Costs	1508	**$26,332**	**$328**	$26,660	$523	$27,183
Renewable Generation Connection Capital Deferral Account	1531	**$31,993**	**$150**	$32,143	$630	$32,773
Stranded Meters	1556	**$92,216**		$92,216		$92,216
RSVA-One Time	1582	**$4,256**	**$2,503**	$6,759	$132	$6,891
Group 2 Sub-total		**$161,711**	**$4,355**	**$166,066**	$1,447	**$167,513**

DEFERRAL AND VARIANCE ACCOUNT BALANCES

Table 9.6 contains account balances from the 2012 Audited Financial Statements as at December 31, 2012 and agrees to the 2012 year end balances for RRR filing E2.1.7 Trial Balance as filed April 30, 2013 with the OEB. The only exception is the recording entry to USoA 1595, Sub-Account for Shared Tax Savings. The accounting for -$3,098.34 was entered in 2013 and omitted from the 2012 audited financial statements and RRR reporting.

Table 9.6: December 31, 2012 Audited Balances

Table 9.6 December 31, 2012 Audited Balances – Group One & Group Two Balanced to Audited Financial Statement

Account Description	Account	December 31, 2012 Principal Balance	December 31, 2012 Interest Balance	Audited Financial Statement Balances December 31, 2012
Group 1 Accounts		**A**	**B**	**Account Balance**
RSVA - Wholesale Market Service Charge	1580	($171,483)	($2,685)	($174,168)
RSVA-One Time	1582	**$4,256**	**$2,503**	$6,759
RSVA - Retail Transmission Network Charge	1584	$18,522	$878	$19,401
RSVA - Retail Transmission Connection Charge	1586	($755)	($698)	($1,453)
RSVA - Power (excluding Global Adjustment)	1588	$39,899	$6,213	$46,112
RSVA - Global Adjustment	1589	($525,543)	($6,710)	($532,253)
Disposition and Recovery of Regulatory Balances-(2012)	1595	($185,935)	($2,160)	($188,095)
Group 1 Sub-Total (Including Account 1589 - Global Adjustment)		**($821,039)**	**($2,658)**	($823,697)
Other-Reg Assets - Sub-Account - OEB Cost Assessments	1508	**$6,914**	**$1,374**	$8,288
Other-Reg Assets - Sub-Account - IFRS Transition Costs	1508	**$26,332**	**$328**	$26,660
Renewable Generation Connection Capital Deferral Account	1531	**$31,993**	**$150**	$32,143
Stranded Meters	1556	**$92,216**		$92,216
Group 2 Sub-total		**$157,455**	**$1,852**	**$159,307**
Group 1 & Group 2 Total		**($663,584)**	**($806)**	**($664,390)**

INTEREST RATES

Table 9.7 provides the interest rates that have been used to calculate actual and forecast carrying charges on the accounts in accordance with the methodology approved by the Board in EB-2006-0117 on November 28, 2006.

Table 9.7: Interest Rates Applied to Deferral and Variance Accounts (%)

Prescribed Interest Rates by Quarter														
Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010
1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.2	0.89	0.55	0.55
Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008	Q2 2008	Q1 2008	Q4 2007	Q3 2007	Q2 2007	Q1 2007	Q4 2006	Q3 2006	Q2 2006
0.55	0.55	1	2.45	3.35	3.35	4.08	5.14	5.14	4.59	4.59	4.59	4.59	4.59	4.14

ENERGY SALES AND COST OF POWER EXPENSE BALANCES

The table below maps the energy sales and cost of power expense balances to the USoA accounts effectiver December 31, 2012. The numbers were reconciled to the Audited Financial Statements and FFPC does not make a profit or loss on the sale of commodity.

Table 9.8: Mapping of Energy Sales and COP Expense to Zero Profit

FFPC Energy Breakdown Mapped to USoA Accounts, as of December 31, 2012

		RVSA Breakdown			
	All RSVAs	1588 Power & GA	1580 Wholesale Market	1584 Network	1586 Connection
4006 Residential Energy Sales	-$ 3,018,434.50	-$ 3,018,434.50			
4025 Street Lighting Energy Sales	-$ 76,651.65	-$ 76,651.65			
4035 General Energy Sales	-$ 3,072,296.32	-$ 3,072,296.32			
4050 Revenue Adjustment	-$ 1,191.98	-$ 1,191.98			
4055 Energy Sales for Resale	$ 1,191.98	$ 1,191.98			
4062 Billed WMS	-$ 507,206.23		-$ 507,206.23		
4066 Billed NW	-$ 489,956.38			-$ 489,956.38	
4068 Billed CN	-$ 120,516.68				-$ 120,516.68
	-$ 7,285,061.76	**-$ 6,167,382.47**	**-$ 507,206.23**	**-$ 489,956.38**	**-$ 120,516.68**
4705 Power Purchased	$ 5,996,962.25	$ 5,996,962.25			
4707 Charges - Global Adjustment	$ -	$ -			
4708 Charges-WMS	$ 411,867.68		$ 411,867.68		
4710 Cost of Power Adjustments	$ 262,181.88	$ 262,181.88			
4714 Charges-NW	$ 491,142.75			$ 491,142.75	
4716 Charges-CN	$ 122,907.20				$ 122,907.20
	$ 7,285,061.76	**$ 6,259,144.13**	**$ 411,867.68**	**$ 491,142.75**	**$ 122,907.20**
	$ 0.00	**$ 91,761.66**	**-$ 95,338.55**	**$ 1,186.37**	**$ 2,390.52**

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

FFPC is requesting disposition of the variance accounts noted below according to the Report of the Board EB-2009-0046, which states that "at the time of rebasing, all account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline."

FFPC has followed the guidelines in the Report of the Board and requests disposition over a one-year period. FFPC has provided a continuity schedule of the accounts listed below in Appendix A of this exhibit.

FFPC is requesting the disposition of the following Group 1 DVA Accounts shown in Table 9.8, below. These amounts are comprised of the audited balances as of December 31, 2012 and the forecasted interest through April 30, 2014.

Table 9.9: Group 1 Deferral/Variance Accounts for Disposition

Proposed Group One Accounts for Disposition								
Account Description	Account	December 31, 2012 Principal Balance	December 31, 2012 Interest Balance	Audited Financial Statement Balances December 31, 2012	Principal Disposition during 2013 as instructed by the Board - EB-2012-0083	Interest Disposition during 2013 as instructed by the Board - EB-2012-0083	Projected Interest on December 31, 2012 balances for Jan 1, 2013 to April 30,2014	Total
Group 1 Accounts		A	B	Account Balance				C
RSVA - Wholesale Market Service Charge	1580	-$171,483	-$2,685	-$174,168	$76,144	$636	-$1,909	-$99,297
RSVA - Retail Transmission Network Charge	1584	$18,522	$878	$19,401	-$17,336	-$508	$31	$1,588
RSVA - Retail Transmission Connection Charge	1586	-$755	-$698	-$1,453	$3,146	-$1,846	-$3	-$156
RSVA - Power (excluding Global Adjustment)	1588	$39,899	$6,213	$46,112	$9,401	-$513	$1,078	$56,078
RSVA - Global Adjustment	1589	-$525,543	-$6,710	-$532,253	$305,824	$6,162	-$4,317	-$224,584
Recovery of Regulatory Asset Balances	1590	$170		$170	-$170			$0
Sub-Total (Including Account 1589 - Global Adjustment)		**-$639,190**	**-$3,001**	-$642,191	$377,009	$3,931	**-$5,120**	**-$266,371**
Sub-Total (Excluding Account 1589 - Global Adjustment)		**-$113,647**	**$3,709**	-$109,938			**-$803**	**-$110,741**

FFPC is requesting the disposition of the following Group 2 DVA Accounts shown in Table 9.9, below. These amounts are comprised of the balances as of December 31, 2012 and the forecasted interest through April 30, 2014.

Table 9.10: Group 2 Deferral/Variance Accounts for Disposition

Group Two Accounts for Disposition						
Account Description	**Account**	**December 31, 2012 Principal Balance**	**December 31, 2012 Interest Balance**	**Audited Financial Statement Balances December 31, 2012**	**Projected Interest on December 31, 2012 balances for Jan 1, 2013 to April 30,2014**	**Total**
Group 2 Accounts						
Other Reg Assets - Sub-Acc - OEB Cost Assessments	1508	**$6,914**	**$1,374**	$8,288	$162	$8,450
Other-Reg Assets - Sub-Acc - IFRS Transition Costs	1508	**$26,332**	**$328**	$26,660	$523	$27,183
Renewable Generation Connection Capital Deferral	1531	**$1,816**	**$150**	$1,966	$630	$2,596
RSVA-One Time	1582	**$4,256**	**$2,503**	$6,759	$132	$6,891
Group 2 Sub-total		**$39,318**	**$4,355**	**$43,673**	$1,447	**$45,120**

FFPC has reduced the disposition recovery for account 1531 to $1,966, which is 6% of the 2012 account balance of $32,772. FFPC is seeking recovery of the remaining $30,806 from IESO as part of FFPC REI Investment recovery,

METHODS OF DISPOSITION

Allocators

FFPC submits the following billing determinants in Table 9.11 assign the Group 1 and Group 2 balances to each rate class. FFPC is proposing to use the billing allocators from FFPC's 2014 Load Forecast. The allocators in the Load Forecast are most appropriate as they have been adjusted for both weather normalized load, customer and connection forecasts and the Conservation Demand Management (CDM) adjustment to the extensive Street Lighting retrofit as detailed in Exhibit 3.

Table 9.11: Billing Determinants

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers
Residential	kWh	3,290	37,751,518		659,196	-
General Service Less Than 50 kW	kWh	405	13,617,679		285,050	-
General Service 50 to 4,999 kW	kW	47	26,376,324	67,294	22,504,279	57,415
Unmetered Scattered Load	kWh	6	48,552			-
Street Lighting	kW	1,006	366,947	1,055	366,947	1,055
						-
Total		**4,754**	**78,161,019**	**68,349**	**23,815,472**	**58,470**

FFPC used the allocators in Deferral/Variance Account Workform, EDDVAR model as shown in the table below to determine the proposed regulatory asset rate rider by rate class for the Group 1 and Group 2 accounts, excluding the Non-RPP rate rider for the 1588 Sub-Account Global Adjustment.

Table 9.12: Allocation of DVA Balances, Excluding 1589

		Amounts	Allocator	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Street Lighting
RSVA - Wholesale Market Service Charge	1580	$ (99,297)	kWh	$ (47,960)	$ (17,300)	$ (33,509)	$ (62)	$ (466)
RSVA - Retail Transmission Network Charge	1584	$ 1,588	kWh	$ 767	$ 277	$ 536	$ 1	$ 7
RSVA - Retail Transmission Connection Charge	1586	$ (156)	kWh	$ (76)	$ (27)	$ (53)	$ (0)	$ (1)
RSVA - Power (excluding Global Adjustment)	1588	$ 56,077	kWh	$ 27,085	$ 9,770	$ 18,924	$ 35	$ 263
Total of Group 1 Accounts (excluding 1589)		**$ (41,789)**		**$ (20,184)**	**$ (7,280)**	**$ (14,102)**	**$ (26)**	**$ (197)**
Other Reg Assets - Sub-Account - OEB Cost Assessments	1508	$ 8,451	kWh	$ 4,082	$ 1,472	$ 2,852	$ 5	$ 40
Other Reg Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 27,183	kWh	$ 13,129	$ 4,736	$ 9,173	$ 17	$ 128
Renewable Generation Connection Capital Deferral Account	1531	$ 1,966	kWh	$ 950	$ 343	$ 663	$ 1	$ 9
RSVA - One-time	1582	$ 6,891	kWh	$ 3,328	$ 1,201	$ 2,325	$ 4	$ 32
Other Deferred Credits	2425	$ (6,144)	kWh	$ (4,252)	$ (523)	$ (61)	$ (8)	$ (1,300)
Total of Group 2 Accounts		**$ 38,346**		**$ 17,237**	**$ 7,229**	**$ 14,952**	**$ 19**	**$ (1,091)**
Total Balance Allocated to each class (excluding 1589)		**$ (3,442)**		**$ (2,947)**	**$ (51)**	**$ 850**	**$ (7)**	**$ (1,288)**

FFPC used the allocators in the table below to determine the proposed regulatory asset rate rider by rate class for the Group 1 for the Non-RPP rate rider for the 1589 Sub-Account Global Adjustment.

Table 9.12: Allocation of Balance- Account 1589 Global Adjustment

		Amounts	Allocator	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Street Lighting
RSVA - Global Adjustment	**1589**	**$ (224,583)**	**Non-RPP**	**$ (6,216)**	**$ (2,688)**	**$ (212,218)**	**$ -**	**$ (3,460)**

Calculation of Rate Riders

The following tables summarizes the variables used to determine the proposed regulatory asset rate rider by rate class for the Group 1 and Group 2 accounts, excluding the Non-RPP rate rider for the 1588 Sub-Account Global Adjustment. The billing determinants are based 2014 Load Forecast study.

The Group 1 and Group 2 disposition balances are calculated on a two-year disposition period as a shorter disposition would create financial hardship for FFPC.

Table 9.13: 2014 Deferral and Variance Account Rate Rider by Class

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)					
Rate Class	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	37,751,518	$ 15,259	0.0002	$/kWh
General Service Less Than 50 kW	kWh	13,617,679	$ 9,313	0.0003	$/kWh
General Service 50 to 4,999 kW	kW	67,294	$ 851	0.0063	$/kW
Unmetered Scattered Load	kWh	48,552	-6	-0.0001	$/kWh
Street Lighting	kW	1,055	-1,287	-0.6102	$/kW
Total			$ 24,129		

Table 9.14 summarizes the variables used to determine the proposed non-RPP global adjustment rate rider by rate class. The billing determinants are based on 2012 Actual data as filed in FFPC's 2012 RRR Filing of April 30, 2013. The non-RPP Global Adjustment balances are calculated using a two-year disposition period.

Table 9.14: 2014 Non-RPP Global Adjustment Rate Rider by Class

Rate Rider Calculation for Non-RPP Global Adjustment Account Balance					
Rate Class	Units	kW / kWh / # of Customers	Allocated Balance (excluding	Rate Rider for Deferral/Va	
Residential	kWh	659,196	-$6,216	-$0.0047	$/kWh
General Service Less Tha	kWh	285,050	-$2,688	-$0.0047	$/kWh
General Service 50 to 4,9	kW	57,415	-$212,218	-$1.8481	$/kW
Unmetered Scattered Lo	kWh		$0		
Street Lighting	kW	1,055	-$3,460	-$1.6400	$/kW
Total			-$224,582		

STRANDED METERS

FFPC is seeking disposition of its stranded meter costs. FFPC's rate order for its Smart Meter Rate Application EB-2012-0327 effective November 1, 2012 issued a revised Tariff of Rates and Charges. FFPC was authorized to use the established sub-account Stranded Meter Costs of Account 1555 to record and track the remaining costs of the stranded conventional meters. The order also stated that the balance of the sub-account should be brought forward for disposition as part of FFPC's next cost of service application.

The net book value of the stranded conventional meters at December 31, 2012 was $92,216.

Table 9.15: Stranded Meter Treatment

Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ 351,835	$ 216,225		$ 135,610		$ 135,610
2007		$ 382,601	$ 230,248		$ 152,353		$ 152,353
2008		$ 390,590	$ 244,323		$ 146,267		$ 146,267
2009		$ 391,865	$ 258,449		$ 133,416		$ 133,416
2010		$ 391,865	$ 272,575		$ 119,290		$ 119,290
2011		$ 391,865	$ 286,700		$ 105,165		$ 105,165
2012		$ 391,865	$ 299,649		$ 92,216		$ 92,216
2013	(1)	$ 391,865	$ 299,649		$ 92,216		$ 92,216

FFPC removed the stranded meter costs from rate base USoA #1860, where the applicable depreciation had been recorded in each year up to December 31, 2012. There were no capital additions or DVA carrying charges added to the stranded assets in 2013.

FFPC has recorded the stranded meters in USoA #1555 sub-account $92,216, indicated above.

FFPC's rate order for its Smart Meter Rate Application EB-2012-0327 effective November 1, 2012, ordered the recovery of FFPC's Smart Meter costs from all metered rate classes, including GS>50kW rate class. The decision and order stated regarding 'Costs Beyond Minimum Functionality', that:

> "FFPC documented $54,402 capital costs and $14,119 operating expenses for costs beyond minimum functionality related to FFPC's smart meter deployment of 47 smart meter for the GS >50 kW rate class, …"

FFPC, in the application, proposed that due to the small number of GS>50 kW customers (47) served by FFPC and the fact that FFPC's larger energy consumers would be excluded from the potential consumption analysis and conservation opportunities that may arise from this information, it sought approval for the recovery of these costs within the appropriate rate class.

The Board approved the recovery of these costs as included and justified in the Application and approved the following rate riders for capital (SMDR) and incremental (SMIRR) cost recovery in the table below:

Table 9.16: Smart Meter Rate Riders

EB-2012-0327 -Smart Meter Disposition Rider (SMDR) & Smart Meter Interim Rate Rider (SMIRR)					
	SMDR	**SMIRR**			
Residential	$3.58	$3.43			
General Service <50 kW	$13.42	$7.19			
General Service >50 kW	$20.71	$9.97			

In preparation for the Smart Meter initiative, FFPC established the costs of the conventional meter value by rate class, as shown in Table 9.3.3.

FFPC established the value of each meter type by analyzing the age of each meter, the initial capital cost (i.e. GS>50kW transformer type meters capital costs $600 per meter- versus self contained mechanical meter- $45.) and any additional capital costs borne by FFPC for the metering installation-i.e. potential and current transformer, etc. FFPC established the stranded meter net book value by rate class as detailed in the column marked '2008'. Subsequent years 2009-2012 are reduced by depreciation.

Table 9.17: Smart Meter Rate Rider Cost Allocation

9.3.3 Stranded Meter History and Cost Allocation							
Rate	**# Meters in Service**	**2008**	**2009**	**2010**	**2011**	**2012**	**Stranded Meter Disposition Rate Rider Per Customer**
							Monthly Charge
Residential	3283	$61,001	$56,192	$49,998	$44,287	$38,578	$0.98
GS <50 kW	422	$66,471	$61,020	$53,975	$47,459	$40,944	$8.09
GS >50 kW	47	$18,795	$16,204	$15,317	$13,419	$12,694	$22.51
					$0		
Net Book Value	3752	**$146,267**	**$133,416**	**$119,290**	**$105,165**	**$92,216**	
Accumulated Amortization		*$244,323*	*$258,449*	*$272,575*	*$286,700*	*$299,649*	
Gross Book Value		$390,590	$391,865	$391,865	$391,865	$391,865	

FFPC is proposing a one-year recovery for Stranded Meter Rate Recovery (SMRR), as above, from all rate classes to align with the cost recovery methodology used in FFPC's smart meter rate order EB-2012-0327.

GREEN ENERGY PLAN – FUNDING ADDER

FFPC has submitted a basic Green Energy Plan to the OPA and has provided a copy in Exhibit 2, Appendix 2-A. The OPA provided a Letter of Communication which has also been provided in Exhibit 2, Appendix 2-A.

At the time of writing of this plan, FFPC estimated capital spending requirements of $35,000 in 2013 and $55,000 in 2014, of which $90,000 in 2013 is in regards to capital investment spending on "Renewable Enabling Improvements" ("REIs") was to be input to calculate the funding adder.

As discussed in its GEA Plan, FFPC plans to purchase two digital numeric relays for an estimated a $25,000 each, as discussed in the Distribution System Plan, that are required as REIs for FIT renewable generation projects. FFPC used the simplified method in which 6% of the costs are to be borne by its customers and 94% by the Province.

Table 9.18 below shows the associated renewable capital investment and the annual program descriptors. FFPC is also seeking the recovery of the audited 2012 DVA balance of Account 1531, Renewable Generation Connection Capital Deferral of $32,142 less the Direct Benefit amount of $1,966.

Table 9.18: FFPC's Renewable Capital Investment.

Appendix 2-FA
Renewable Generation Connection Investment Summary (over the rate setting period)

REI Investments (Direct Benefit at 6%)	2014	2015	2016	2017	2018
Project 1					
Transformer T1 Protection					
Capital Costs	$25,000	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$2,500	$0	$0	$0	$0
Project 2					
Transformer T2 Protection					
Capital Costs	$25,000	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$2,500	$0	$0	$0	$0
Project 3					
Station Data Acquisition System					
Capital Costs	$0	$20,000	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$2,000	$0	$0	$0
Project 4					
Station Communication Network Installation					
Capital Costs	$0	$20,000	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$2,000	$0	$0	$0
Project 5					
Station OCB Protection					
Capital Costs	$0	$0	$20,000	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$2,000	$0	$0
Project 6					
Station Supervisory Control					
Capital Costs	$0	$0	$0	$45,000	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$3,500	$0
Project 7					
Station DC System Monitoring & Remote Annunciation					
Capital Costs	$0	$0	$0	$0	$12,000
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$1,200
Total Capital Costs	**$ 50,000**	**$ 40,000**	**$ 20,000**	**$ 45,000**	**$ 12,000**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ 5,000**	**$ 4,000**	**$ 2,000**	**$ 3,500**	**$ 1,200**

FFPC requests a funding adder to be included in its rates, based on the Incremental Revenue Requirement Calculation provided below in Table 9.19. FFPC is proposing to recover a funding rate rider of $.0566 per month from all customers over the five year period and seeks a Monthly Adder Paid by IESO of $267. An electronic version of this model has been provided as part of this application.

Table 9.19 Incremental Revenue Requirement & Funding Adder Calculation

	2012		2013		2014		2015		2016		2017		2018		
Net Fixed Assets		$ 32,142				$ 50,000		$ 20,000		$ 20,000		$ 45,000		$ 12,000	
OM&A	$ -		$ -		$5,000		$ 2,000		$2,000		$ 3,500		$ 1,200		
WCA	15.0%	$ -	13.0%	$ -	13.0%	$ 650	13.0%	$ 260	13.0%	$ 260	13.0%	$ 455	13.0%	$ 156	
Rate Base		$ 32,142		$ -		$ 50,650		$ 20,260		$ 20,260		$ 45,455		$ 12,156	
Deemed ST Debt	50%	$ 16,071	50%	$ -	4%	$ 2,026	4%	$ 810	4%	$ 810	4%	$ 1,818	4%	$ 486	
Deemed LT Debt	50%	$ 16,071	50%	$ -	56%	$ 28,364	56%	$ 11,346	56%	$ 11,346	56%	$ 25,455	56%	$ 6,807	
Deemed Equity		$ -	0%	$ -	40%	$ 20,260	40%	$ 8,104	40%	$ 8,104	40%	$ 18,182	40%	$ 4,862	
ST Interest	6.25%	$ 1,004	2.11%	$ -	2.11%	$ 43	2.11%	$ 17	2.11%	$ 17	2.11%	$ 38	2.11%	$ 10	
LT Interest	0.00%	$ -	4.88%	$ -	4.88%	$ 1,384	4.88%	$ 554	4.88%	$ 554	4.88%	$ 1,242	4.88%	$ 332	
ROE	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	
		$ 1,004		$ -		$ 1,427		$ 571		$ 571		$ 1,281		$ 342	
OM&A						$ 5,000		$ 2,000		$ 2,000		$ 3,500		$ 1,200	
Amortization		$ 357		$ 714		$ 1,270		$ 2,270		$ 2,937		$ 4,292		$ -	
Grossed-up PILs		$ -		$ -		$ -		$ -		$ -		$ -		$ -	
Revenue Requirement		$ 1,362		$ 714		$ 7,697		$ 4,841		$ 5,507		$ 9,073		$ 1,542	$ 30,736
Direct Benefit															
OM&A		$ -		$ -		$ 5,000		$ 2,000		$ 2,000		$ 3,500		$ 1,200	
Capital		$ 1,362		$ 714		$ 2,697		$ 2,841		$ 3,507		$ 5,573		$ 342	
Direct Benefit % on capital		6.00%		6.00%		6.00%		6.00%		6.00%		6.00%		0.00%	
Direct Benefit on capital		$ 82		$ 43		$ 162		$ 170		$ 210		$ 334		$ -	
Total Direct Benefit		$ 82		$ 43		$ 5,162		$ 2,170		$ 2,210		$ 3,834		$ 1,200	$ 14,702
Total # of Customers (excl connections)		3,742		3,742		3,742		3,742		3,742		3,742		3,742	3,742
GEA Rate Adder		$ 0.0018		$0.0010		$ 0.1150		$ 0.0483		$ 0.0492		$ 0.0854		$0.0267	$ 0.0655
Provincial Rate Protection		$ 1,280		$ 671		$ 2,535		$ 2,670		$ 3,297		$ 5,238		$ 342	$ 16,034
Monthly Adder Amount Paid by IESO		$ 107		$ 56		$ 211		$ 223		$ 275		$ 437		$ 29	$ 267

Lost Revenue Adjustment Mechanism ("LRAM") and Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")

Summary

In accordance with the Board's Guidelines for Electricity Distributor Conservation and Demand Management ("CDM Guidelines") issued on April 26, 2012, Fort Frances Power Corporation ("FFPC") requests approval for the recovery of lost revenue reflecting savings from its Conservation and Demand Management ("CDM") activities in 2011, 2012 and 2013 resulting from pre-2011 programs as well as 2011 and 2012 programs. The LRAM claim for CDM activities in 2011, 2012 and 2013 from pre-2011 programs reflect the persistent savings from 2006 to 2010 Ontario Power Authority (OPA) programs that occurred from 2011 to 2013. The LRAM claim from pre-2011 programs is $21,917 plus interest to April 30, 2014 of $616 for a total of $22,523.

In addition, in the CDM Guidelines, the Board stated that it will adopt an approach for LRAM for the 2011-2014 CDM program period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board authorized the establishment of LRAM account 1568 (LRAMVA) to capture, at the customer rate class level, the difference between:

- The results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011-2014 for both Board-Approved CDM programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or are delivered for the distributor by the third party under contract (in the distributor's franchise area), and;

- The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded in rates).

FFPC has verified results from the OPA for 2011 and 2012. Based on these results, FFPC is requesting that $5,050 be included in account 1568 and be recovered as part of the standard deferral and variance account recovery process.

LRAM for 2011 to 2013 CDM activities from pre-2011 programs

FFPC participated in over fifteen OPA provincial programs from 2006 to 2010. Persistent savings resulting from these OPA-sponsored programs have resulted in foregone revenues from 2011 to 2013 of $21,917 plus interest to April 30, 2014 of $616 for a total LRAM claim of $22,523. FFPC is seeking to recover this lost revenue its 2014 rates. FFPC will not be seeking recovery for any ongoing savings from per-2011 programs past 2013 as these savings are assumed to be included in the proposed 2014 load forecast that supports this application. The detailed calculations supporting this claim are provided in a live Excel spreadsheet named **FFPC LRAM 2006-2010 Programs Persist into 2011 to 2013.** The Excel spreadsheet also provides information on the savings by program by year on a gross and net basis and outlines the free ridership percentage. The information on the level of achieved savings used in the spreadsheet was provided by OPA in a file named **FFPC 2006-2010 Final OPA CDM Results** which is also a live Excel spreadsheet.

LRAM was calculated as the product of the demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to each respective class. It assumed the savings reported by the OPA are on a calendar year basis. As a result, the variable distribution charge used in the LRAM calculations has been adjusted to a calendar year basis. For the purposes of this request, FFPC has assumed only OPA sponsored program are eligible for LRAM. All results are net of free ridership.

The impact of CDM savings was not reflected in the approved load forecast used to support the approved rates in FFPC's 2006 EDR application which was FFPC's last cost of service application. It is FFPC submission that the entire actual load reduction achieved by the 2006 to 2010 OPA sponsored programs for the years 2011 to 2013 is subject to LRAM treatment at this time. The

LRAM associated with the actual load reduction achieved by the 2006 to 2010 OPA sponsored programs for the years 2006 to 2010 was approved in FFPC's 2012 rate application (EB-2011-0146) for rates effective May 1, 2012.

The following Table 9.18 provides the summary of the LRAM calculation and rate rider by rate class. FFPC is requesting a 1 (One) year rate rider for the LRAM claim.

Table 9.20: LRAM Calculation and Rate Rider by Rate Class for Persistence of Pre-2011 Programs into 2011 to 2013

Rate Class Allocation (kWh Saved)			2011	2012	2013	Total
Residential (Market - Consumer)	2006 to 2010 OPA Programs		624,150	594,922	582,455	1,801,527
General Service < 50 kW (Market - Business)	2006 to 2010 OPA Programs		318,562	318,562	318,562	955,687
Total			942,713	913,484	901,018	2,757,215
Rate Class Distribution Volumetric Rates		Eff: May 1, 2010	Eff: May 1, 2011	Eff: May 1, 2012	Eff: May 1, 2013	
Residential ($/kWh)		0.0083	0.0087	0.0088	0.0088	
General Service Less Than 50 kW ($/kWh)		0.0061	0.0065	0.0066	0.0066	
Rate Class Distribution Volumetric Rates (Annualized)			2011	2012	2013	
Residential ($/kWh)			0.0086	0.0088	0.0088	
General Service Less Than 50 kW ($/kWh)			0.0064	0.0066	0.0066	
LRAM			2011	2012	2013	Total
Residential (/kWh)			$5,351	$5,215	$5,126	$15,692
General Service Less Than 50 kW (/kWh)			$2,030	$2,092	$2,103	$6,225
Total			$7,381	$7,307	$7,228	$21,917
LRAM Rate Rider	LRAM	Interest	Total LRAM Claim	2014 Proposed Billing Determinant	UOM	LRAM Rider - One Year	
Residential	$15,692	$434	$16,126	37,751,518	kWh	0.0004	($/kWh)
General Service Less Than 50 kW	$6,225	$172	$6,397	13,617,679	kWh	0.0005	($/kWh)
Total	$21,917	$606	$22,523				

LRAMVA for 2011 and 2012 OPA programs

On March 31, 2010, the Minister of Energy and Infrastructure issued a directive (the "Directive") to the Board with regards to electricity CDM targets to be met by licensed electricity distributors ("Distributors"). The Directive required that the Board amend the licenses of Distributors to add, as a condition of license, the requirement for Distributor to achieve reductions in electricity demand through the delivery of CDM programs over a four-year period beginning January 1, 2011. Section 12 of the Directive required that the Board have regard to the objective that lost revenues that result from CDM Programs should not act as a disincentive to a Distributor.

In keeping with the Directive, the Board adopted a mechanism, outlined in the CDM Guidelines, to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by Distributors between 2011 and 2014 and the level of activities embedded into rates through the Distributors load forecast in an LRAMVA

With regards to LRAMVA calculations, FFPC has relied on the most recent final evaluation report from the OPA in support of its LRAMVA calculation for its Contracted Province-wide CDM programs for 2011 and 2012. The OPA has used the most recent input assumptions available at the time of the program evaluation.

As discussed above, none of the load reductions estimated have been factored into the load forecast supporting FFPC's current rates since 2006 was the last cost of service year. The reduction in demand (kWh and MW) related to the 2011 to 2014 OPA Programs has been incorporated into FFPC's load forecast for May 1, 2014 onward. FFPC has calculated the LRAMVA for 2011 and 2012 amounts using FFPC's annualized variable distribution rates.

It is FFPC understanding that the final 2011 and 2012 OPA have been verified as part of the OPA's process to finalize these results. In addition, the LRAMVA amount is significantly below

the materiality of $50,000. Based on these two factors FFPC has not incurred the additional expense to have these results once again verified by a third party.

FFPC has calculated the LRAMVA 2011 and 2012 amounts by rate class based upon the OPA's 2011 Final Annual Report released on September 1, 2012 and the OPA's 2012 Final Annual Report released on August 30, 2013. A copy of the OPA's final 2011 evaluation report is provided as Appendix B to this Exhibit. A copy of the OPA's final 2012 evaluation report is provided as Appendix C. The LRAMVA amounts for the Residential rate classification are calculated based upon the Incremental Energy Savings for the Consumer Programs as reported by the OPA. The LRAMVA amounts for the General Service < 50 kW are based on an allocation of the Incremental Energy Savings for Business Programs as reported by the OPA. The LRAMVA amounts by 2011 and 2012 rate class are provided in Table 9.19 along with calculated carrying charges on the LRAMVA amounts from January 1, 2011 to April 30, 2014 using the Board's prescribed rates. Detailed calculations are provided in the live Excel file named **FFPC LRAMVA 2011 and 2012 Programs.**

Table 9.21: LRAMVA Calculation by Rate Class for 2011 and 2012 Program

Rate Class Allocation (kWh Saved)	2011	2012	Total
Residential (Market - Consumer)	81,974	150,179	232,152
General Service < 50 kW (Market - Business)	25,159	414,547	439,706
Total	107,133	564,726	671,858
Rate Class Distribution Volumetric Rates	Eff: May 1, 2010	Eff: May 1, 2011	Eff: May 1, 2012
Residential ($/kWh)	0.0083	0.0087	0.0088
General Service Less Than 50 kW ($/kWh)	0.0061	0.0065	0.0066
Rate Class Distribution Volumetric Rates (Annualized)	2011	2012	
Residential ($/kWh)	0.0086	0.0088	
General Service Less Than 50 kW ($/kWh)	0.0064	0.0066	
LRAMVA	2011	2012	Total
Residential (/kWh)	$703	$1,317	$2,019
General Service Less Than 50 kW (/kWh)	$160	$2,722	$2,883
Total	$863	$4,039	$4,902
LRAMVA - Account 1568 Allocation	LRAMVA	Interest	Total
Residential	$2,019	$61	$2,080
General Service Less Than 50 kW	$2,883	$87	$2,969
Total	$4,902	$148	$5,050

With regards to the disposition of the LRAMVA for 2011 and 2012, FFPC requests recovery of the LRAMVA amount be included in account 1568 as part of the standard deferral and variance account recovery process and that account 1568 be allocated to rate class as shown in Table 9.19. The recovery of account 1568 will be included in the volumetric deferral and variance account rate riders to be recovered over a one-year period, effective May 1, 2014.

ACCOUNTING CHANGES UNDER CGAAP

On July 17, 2012, the Board issued a letter stating they will permit electricity distributors electing to remain on Canadian GAAP ("CGAAP") in 2012 to implement regulatory accounting changes for depreciation expense and capitalization policies effective on January 1, 2012.

FFPC decided to make the change to depreciation and capitalization policies effective January 1, 2013. The "Kinectrics Report, (EB-2010-0178)" dated July 8, 2010 provided the necessary framework that FFPC used to underpin FFPC's Asset Management Policy that determined FFPC's "Expected Useful Life" determinants as detailed in Exhibit 2.

Impact on Fixed Assets

FFPC changed its' accounting policies under CGAAP for depreciation and the capitalization policy commencing January 1, 2013. FFPC has followed the accounting treatment as published in the July 2012 FAQs. The accounting requirements and treatment OHL is Account 1576 to record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the Board under Canadian GAAP in 2013.

FFPC has provided the completed Appendices 2-CS and 2-CT below as found in the Board Chapter 2 Appendices.

Appendix 2-CS – Former CGAAP

Year 2013 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2013 Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (I)	Variance [2] (m) = (h) - (I)
1611	Computer Software (Formally known as Account 1925)	$ 29,854	$ 11,789	$ 18,065	$ 27,500	$ 31,815	5.00	20.00%	$ 6,363	$ 4,614	$ 1,749
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0.00%	$ -		$ -
1805	Land	$ 100,000		$ 100,000		$ 100,000	0.00	0.00%	$ -		$ -
1808	Buildings	$ 823,377	$ 555,434	$ 267,943	$ 2,000	$ 268,943	25.00	4.00%	$ 10,758	$ 15,153	-$ 4,395
1810	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 1,076,223		$ 1,076,223	$ 2,000	$ 1,077,223	40.00	2.50%	$ 26,931	$ 26,174	$ 757
1820	Distribution Station Equipment <50 kV	$ -		$ -		$ -		0.00%	$ -		$ -
1825	Storage Battery Equipment	$ 9,565		$ 9,565	$ 2,000	$ 10,565	10.00	10.00%	$ 1,057		$ 1,057
1830	Poles, Towers & Fixtures	$ 5,169,630	$ 1,166,745	$ 4,002,885	$ 121,891	$ 4,063,830	25.00	4.00%	$ 162,553	$ 160,847	$ 1,706
1835	Overhead Conductors & Devices	$ 401,309	$ 401,309	-$ 0	$ 14,500	$ 7,250	25.00	4.00%	$ 290		$ 290
1840	Underground Conduit	$ 2,183		$ 2,183		$ 2,183	25.00	4.00%	$ 87		$ 87
1845	Underground Conductors & Devices	$ 97,937		$ 97,937	$ 8,769	$ 102,322	25.00	4.00%	$ 4,093	$ 4,004	$ 89
1850	Line Transformers	$ 1,209,373	$ 566,794	$ 642,579	$ 15,000	$ 650,079	25.00	4.00%	$ 26,003	$ 24,897	$ 1,106
1855	Services (Overhead & Underground)	$ 7,197		$ 7,197	$ 2,000	$ 8,197	25.00	4.00%	$ 328		$ 328
1860	Meters	-$ 0		-$ 0		-$ 0		0.00%	$ -		$ -
1860	Meters (Smart Meters)	$ 841,418		$ 841,418		$ 841,418	15.00	6.67%	$ 56,095	$ 56,094	$ 1
1905	Land	$ -		$ -		$ -		0.00%	$ -		$ -
1908	Buildings & Fixtures	$ 405,109	$ 248,358	$ 156,751	$ 24,000	$ 168,751	25.00	4.00%	$ 6,750	$ 74	$ 6,676
1910	Leasehold Improvements	$ 86,122	$ 10,506	$ 75,616	$ 1,500	$ 76,366	30.00	3.33%	$ 2,546	$ 2,545	$ 1
1915	Office Furniture & Equipment (10 years)	$ 117,407	$ 81,373	$ 36,034	$ 3,000	$ 37,534	10.00	10.00%	$ 3,753	$ 3,729	$ 24
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 47,053	$ 20,645	$ 26,408	$ 5,900	$ 29,358	5.00	20.00%	$ 5,872	$ 3,456	$ 2,416
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment	$ 696,397	$ 483,347	$ 213,050	$ 120,000	$ 273,050	10.00	10.00%	$ 27,305	$ 22,393	$ 4,912
1935	Stores Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 153,134	$ 91,185	$ 61,949	$ 11,500	$ 67,699	10.00	10.00%	$ 6,770	$ 6,808	-$ 38
1945	Measurement & Testing Equipment	$ -		$ -	$ 1,500	$ 750	10.00	10.00%	$ 75	$ 150	-$ 75
1950	Power Operated Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1955	Communications Equipment	$ -		$ -	$ 900	$ 450	5.00	20.00%	$ 90	$ 90	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -		0.00%	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1970	Load Management Controls - Customer Premises	$ -		$ -		$ -		0.00%	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -		0.00%	$ -		$ -
1980	System Supervisor Equipment	$ -		$ -		$ -		0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -		0.00%	$ -		$ -
1990	Other Tangible Property	$ -		$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants	$ -		$ -		$ -		0.00%	$ -		$ -
etc.				$ -		$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	**$11,273,288**	**$ 3,637,485**	**$ 7,635,803**	**$ 363,960**	**$ 7,817,783**			**$ 347,717**	**$ 331,028**	**$ 16,689**

Appendix 2-CT – New Revised CGAAP

Appendix 2-CT
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2013 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 5,538	$ 27,500	1.20	5.00	20.00%	$ 4,615	$ 2,750	$ 7,365	$ 4,614	$ 2,751	$ 5,500		$ 10,115
1612	Land Rights (Formally known as Account 1906)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land	$ 100,000				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings	$ 81,096	$ 2,000	23.50	62.00	1.61%	$ 3,451	$ 16	$ 3,467	$ 15,153	-$ 11,686	$ 32		$ 3,483
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 138,298	$ 2,000	21.00	62.00	1.61%	$ 6,586	$ 16	$ 6,602	$ 26,174	-$ 19,572	$ 32		$ 6,618
1820	Distribution Station Equipment <50 kV					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment	$ 9,565	$ 2,000	6.00	15.00	6.67%	$ 1,594	$ 67	$ 1,661		$ 1,661	$ 133		$ 1,728
1830	Poles, Towers & Fixtures	$ 1,184,058	$ 121,891	23.21	45.00	2.22%	$ 51,015	$ 1,354	$ 52,369	$ 160,847	-$ 108,478	$ 2,709	$ 16,552	$ 37,172
1835	Overhead Conductors & Devices	$ 400,558	$ 14,500	26.00	60.00	1.67%	$ 15,406	$ 121	$ 15,527		$ 15,527	$ 242		$ 15,648
1840	Underground Conduit	$ 2,183		40.00	60.00	1.67%	$ 55	$ -	$ 55		$ 55	$ -		$ 55
1845	Underground Conductors & Devices	$ 71,774	$ 8,769	13.00	40.00	2.50%	$ 5,521	$ 110	$ 5,631	$ 4,004	$ 1,627	$ 219		$ 5,740
1850	Line Transformers	$ 170,974	$ 15,000	11.21	40.00	2.50%	$ 15,252	$ 188	$ 15,439	$ 24,897	-$ 9,458	$ 375		$ 15,627
1855	Services (Overhead & Underground)	$ 7,197	$ 2,000	7.00	40.00	2.50%	$ 1,028	$ 25	$ 1,053		$ 1,053	$ 50		$ 1,078
1860	Meters					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 631,655		10.00	15.00	6.67%	$ 63,166	$ -	$ 63,166	$ 56,094	$ 7,072	$ -		$ 63,166
1905	Land					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures	$ 151,642	$ 24,000	17.50	40.00	2.50%	$ 8,665	$ 300	$ 8,965	$ 74	$ 8,891	$ 600		$ 9,265
1910	Leasehold Improvements	$ 67,949	$ 1,500	15.00	20.00	5.00%	$ 4,530	$ 38	$ 4,567	$ 2,545	$ 2,022	$ 75		$ 4,605
1915	Office Furniture & Equipment (10 years)	$ 13,728	$ 3,000	5.00	15.00	6.67%	$ 2,746	$ 100	$ 2,846	$ 3,729	-$ 883	$ 200	$ 376	$ 2,570
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 4,309	$ 5,900	2.00	5.00	20.00%	$ 2,155	$ 590	$ 2,745		$ 2,745	$ 1,180	$ 1,309	$ 2,026
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -	$ 3,456	-$ 3,456	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment	$ 196,721	$ 120,000	9.00	15.00	6.67%	$ 21,858	$ 4,000	$ 25,858	$ 22,393	$ 3,465	$ 8,000		$ 29,858
1935	Stores Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 13,120	$ 11,500	2.00	10.00	10.00%	$ 6,560	$ 575	$ 7,135	$ 6,808	$ 327	$ 1,150	$ 443	$ 7,267
1945	Measurement & Testing Equipment		$ 1,500	8.00	8.00	12.50%	$ -	$ 94	$ 94	$ 150	-$ 56	$ 188		$ 188
1950	Power Operated Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communications Equipment		$ 900	10.00	10.00	10.00%	$ -	$ 45	$ 45	$ 90	-$ 45	$ 90		$ 90
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1970	Load Management Controls - Customer Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1990	Other Tangible Property					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributions & Grants					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
etc.						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
						0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	**$ 3,250,365**	**$ 363,960**				**$ 214,201**	**$ 10,387**	**$ 224,589**	**$ 331,028**	**-$ 106,439**	**$ 20,775**	**$ 18,680**	**$ 216,296**

Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

	2006 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				3,250,363					
Net Additions - Note 4				256,922					
Net Depreciation (amounts should be negative) - Note 4				-223,990					
Closing net PP&E (1)				3,283,295					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				3,250,363					
Net Additions - Note 4				256,922					
Net Depreciation (amounts should be negative) - Note 4				-109,261					
Closing net PP&E (2)				3,398,024					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-114,729					

Effect on Deferral and Variance Account Rate Riders	
Closing balance in Account 1576	- 114,729
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 22,946
Amount included in Deferral and Variance Account Rate Rider Calculation	- 137,675

WACC	4.00%
# of years of rate rider disposition period	5

FFPC will complete a journal entry for the financial differences arising from the accounting changes at the fiscal year end of 2013 and will discontinue this when FFPC rebases its rates through a cost of service application. The offsetting entry will be recorded in Account 4305, Regulatory Debit, or Account 4310, Regulatory Credit.

FFPC has included a credit balance in Account 1576 of -$137,675 in the EDDVAR continuity schedule in order to calculate rate riders. FFPC has included the rate of return component in the amount refunded to ratepayers, however this amount will not be recorded in Account 1576. No interest carrying charges or a rate of return is permitted on this account.

FFPC has calculated this adjustment to depreciation expense at 2013 year end for the amount of -$137,675 that will be refunded to the rate payers in this application. FFPC is proposing a five year period of disposition to be consistent with the new IRM period.

FFPC's proposed disposition rate riders for account 1576 are detailed below:

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) **5**

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576	
Residential	kWh	37,751,518	-$ 66,497	- **0.0004**	$/kW
General Service Less Than 50 kW	kWh	13,617,679	-$ 23,987	- **0.0004**	$/kW
General Service 50 to 4,999 kW	**kW**	67,294	-$ 46,460	- **0.1381**	**$/kW**
Unmetered Scattered Load	kWh	48,552	-$ 86	- **0.0004**	$/kW
Street Lighting	**kW**	1,055	-$ 646	- **0.1225**	**$/kW**
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 137,675**		

APPENDIX A

Fort Frances Power Corporation

2014 DEFERRAL AND VARIANCE ACCOUNT CONTINUITY SCHEDULE

Account Descriptions	Account Number	Projected Interest on Dec-31-12 Balances: Projected Interest from Jan 1, 2013 to December 31, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest on Dec-31-12 Balances: Projected Interest from January 1, 2014 to April 30, 2014 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest on Dec-31-12 Balances: Total Claim	2.1.7 RRR: As of Dec 31-12	Variance RRR vs. 2012 Balance (Principal + Interest)
LRAM Variance Account	1568	$753		$27,572		-$26,819
Total including Account 1568		-$2,003	-$918	-$200,454	-$568,512	$10,131
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555			$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555			$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555			$92,216	$92,216	$0
Smart Meter OM&A Variance[10]	1556			$0		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575			$0		$0
Accounting Changes Under CGAAP Balance + Return Component[9]	1576			-$137,675		$137,675
The following is not included in the total claim but are included on a memo basis:						
Deferred PILs Contra Account [5]	1563			$0		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$0		$0
Disposition and Recovery of Regulatory Balances[7]	1595	-$388		-$569,423	-$188,095	$0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g
negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wri

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transac

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obli
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from Ja
balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or re

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the
1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in cell F3
relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)



Deferral/Variance Ac
for 2014 I

Account Descriptions	Account Number	Projected Interest on Dec-31-12 Balances: Projected Interest from Jan 1, 2013 to December 31, 2013 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest on Dec-31-12 Balances: Projected Interest from January 1, 2014 to April 30, 2014 on Dec 31 -12 balance adjusted for disposition during 2013 [6]	Projected Interest on Dec-31-12 Balances: Total Claim	2.1.7 RRR: As of Dec 31-12	Variance RRR vs. 2012 Balance (Principal + Interest)
Group 1 Accounts						
LV Variance Account	1550			$0		$0
RSVA - Wholesale Market Service Charge	1580	-$1,432	-$477	-$99,297	-$174,168	$0
RSVA - Retail Transmission Network Charge	1584	$23	$8	$1,588	$19,401	-$0
RSVA - Retail Transmission Connection Charge	1586	-$2	-$1	-$156	-$1,453	$1
RSVA - Power (excluding Global Adjustment)	1588	$808	$269	$56,077	$46,112	$0
RSVA - Global Adjustment	1589	-$3,238	-$1,079	-$224,583	-$532,253	-$1
Recovery of Regulatory Asset Balances	1590			-$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595			$0		$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$3,841	-$1,280	-$266,372	-$642,361	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$603	-$201	-$41,789	-$110,108	$1
RSVA - Global Adjustment	**1589**	-$3,238	-$1,079	-$224,583	-$532,253	-$1
Group 2 Accounts						
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$122	$41	$8,451	$8,288	$0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$0		$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$392	$131	$27,183	$26,660	$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$0		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$0		$0
Other Regulatory Assets - Sub-Account - Other [4]	1508			$0		$0
Retail Cost Variance Account - Retail	1518			$0		$0
Misc. Deferred Debits	1525			$0		-$0
Renewable Generation Connection Capital Deferral Account	1531	$472	$157	$1,966	$32,142	$30,806
Renewable Generation Connection OM&A Deferral Account	1532			$0		$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0		$0
Smart Grid Capital Deferral Account	1534			$0		$0
Smart Grid OM&A Deferral Account	1535			$0		$0
Smart Grid Funding Adder Deferral Account	1536			$0		$0
Retail Cost Variance Account - STR	1548			$0		$0
Board-Approved CDM Variance Account	1567			$0		$0
Extra-Ordinary Event Costs	1572			$0		$0
Deferred Rate Impact Amounts	1574			$0		$0
RSVA - One-time	1582	$99	$33	$6,891	$6,759	-$0
Other Deferred Credits	2425			-$6,144		$6,144
Group 2 Sub-Total		$1,085	$362	$38,346	$73,849	$36,950
Deferred Payments in Lieu of Taxes	1562			$0		$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$0		$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$2,756	-$918	-$228,026	-$568,512	$36,950

Account Descriptions	Account Number	2012										2013			
		Other [2] Adjustments during Q1 2012	Other [2] Adjustments during Q2 2012	Other [2] Adjustments during Q3 2012	Other [2] Adjustments during Q4 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Adjustments during 2012 - other [2]	Closing Interest Amounts as of Dec-31-12	Principal Disposition during 2013 - instructed by Board	Interest Disposition during 2013 - instructed by Board	Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2013	Closing Interest Balances as of Dec 31-12 Adjusted for Dispositions during 2013
LRAM Variance Account	1568					$0	$0			$26,819	$26,819			$0	$26,819
Total including Account 1568		$0	$0	$0	$27,673	-$576,008	-$75,513	-$12,649	-$89,515	-$3,987	-$2,635	-$377,179	-$3,931	-$198,829	$1,296
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555					$0	$0				$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555					$0	$0				$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555				$92,216	$92,216	$0	$0			$0			$92,216	$0
Smart Meter OM&A Variance[10]	1556					$0	$0				$0			$0	$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575					$0	$0				$0			$0	$0
Accounting Changes Under CGAAP Balance + Return Component[9]	1576				-$137,675	-$137,675	$0				$0			-$137,675	$0
The following is not included in the total claim but are included on a memo basis:															
Deferred PILs Contra Account [5]	1563					$0	$0				$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$0	$0				$0			$0	$0
Disposition and Recovery of Regulatory Balances[7]	1595					-$96,419	$0	-$2,160	$89,515		-$91,676	$377,009	$3,931	-$473,428	-$95,607

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wri

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transac

Please describe "other" components of 1508 and add more component lines if necessary.

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Include Account 1595 as part of Group 1 accounts (lines 31, 32, 33 and 34) for review and disposition if the recovery (or re

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit: "By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1 balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the ' 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please provide the value in cell F3 relevant Chapter 2 Appendix (i.e. 2-ED or 2-EE).

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)



Deferral/Variance Ac
for 2014 I

Account Descriptions	Account Number	2012										2013			
		Other [2] Adjustments during Q1 2012	Other [2] Adjustments during Q2 2012	Other [2] Adjustments during Q3 2012	Other [2] Adjustments during Q4 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Adjustments during 2012 - other [2]	Closing Interest Amounts as of Dec-31-12	Principal Disposition during 2013 - instructed by Board	Interest Disposition during 2013 - instructed by Board	Closing Principal Balances as of Dec 31-12 Adjusted for Dispositions during 2013	Closing Interest Balances as of Dec 31-12 Adjusted for Dispositions during 2013
Group 1 Accounts															
LV Variance Account	1550					$0	$0				$0			$0	$0
RSVA - Wholesale Market Service Charge	1580					-$171,483	$28,158	-$3,541	$27,302		-$2,685	-$76,144	-$636	-$95,339	-$2,049
RSVA - Retail Transmission Network Charge	1584					$18,522	-$12,537	$711	-$12,705		$879	$17,336	$508	$1,186	$371
RSVA - Retail Transmission Connection Charge	1586					-$755	-$126,542	-$2,605	-$128,449		-$698	-$3,146	$1,846	$2,391	-$2,544
RSVA - Power (excluding Global Adjustment)	1588					$39,899	$37,180	$5,608	$36,575		$6,213	-$9,401	$513	$49,300	$5,700
RSVA - Global Adjustment	1589					-$525,543	-$2,443	-$6,542	-$2,276		-$6,709	-$305,824	-$6,162	-$219,719	-$547
Recovery of Regulatory Asset Balances	1590					$1	-$3,330	-$147	-$3,476		-$1			$1	-$1
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$0	$0				$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$0	$0				$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$0	$0				$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595					$0	$0				$0			$0	$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	-$639,359	-$79,514	-$6,517	-$83,029	$0	-$3,002	-$377,179	-$3,931	-$262,180	$929
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	-$113,816	-$77,071	$25	-$80,753	$0	$3,707	-$71,355	$2,231	-$42,461	$1,476
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	-$525,543	-$2,443	-$6,542	-$2,276	$0	-$6,709	-$305,824	-$6,162	-$219,719	-$547
Group 2 Accounts															
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$6,914	$1,284	$90			$1,374			$6,914	$1,374
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$26,332	$7	$321			$328			$26,332	$328
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$0	$0				$0			$0	$0
Other Regulatory Assets - Sub-Account - Other [4]	1508					$0	$0				$0			$0	$0
Retail Cost Variance Account - Retail	1518					$0	$0				$0			$0	$0
Misc. Deferred Debits	1525					$0	$183	$10	$193		$0			$0	$0
Renewable Generation Connection Capital Deferral Account	1531				$27,673	$31,993	$86	$64		-$30,806	-$30,656			$31,993	-$30,656
Renewable Generation Connection OM&A Deferral Account	1532					$0	$0				$0			$0	$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0	$0				$0			$0	$0
Smart Grid Capital Deferral Account	1534					$0	$0				$0			$0	$0
Smart Grid OM&A Deferral Account	1535					$0	$0				$0			$0	$0
Smart Grid Funding Adder Deferral Account	1536					$0	$0				$0			$0	$0
Retail Cost Variance Account - STR	1548					$0	$0				$0			$0	$0
Board-Approved CDM Variance Account	1567					$0	$0				$0			$0	$0
Extra-Ordinary Event Costs	1572					$0	$0				$0			$0	$0
Deferred Rate Impact Amounts	1574					$0	$0				$0			$0	$0
RSVA - One-time	1582					$4,256	$2,440	$63			$2,503			$4,256	$2,503
Other Deferred Credits	2425					-$6,144	$0				$0			-$6,144	$0
Group 2 Sub-Total		$0	$0	$0	$27,673	$63,351	$4,001	$547	$193	-$30,806	-$26,452	$0	$0	$63,351	-$26,452
Deferred Payments in Lieu of Taxes	1562					$0	$0	-$6,679	-$6,679	$0	$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$0	$0				$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$0	$0				$0			$0	$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	$0	$0	$27,673	-$576,008	-$75,513	-$12,649	-$89,515	-$30,806	-$29,454	-$377,179	-$3,931	-$198,829	-$25,523

Account Descriptions	Account Number	2011										2012		
		Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11	Opening Principal Amounts as of Jan-1-12	Transactions Debit / (Credit) during 2012 excluding interest and adjustments [3]	Board-Approved Disposition during 2012
LRAM Variance Account	1568	$0				$0	$0				$0	$0		
Total including Account 1568		-$290,384	-$9,771	$0	-$353,392	-$653,547	-$73,490	-$2,024	$0	$0	-$75,513	-$653,547	-$279,457	-$329,323
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0				$0	$0				$0	$0		
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0	$0		
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575													
Accounting Changes Under CGAAP Balance + Return Component[9]	1576													
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0	$0		
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0	$0		
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0	$0	$232,903	$329,322

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Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)



Deferral/Variance Ac for 2014 I

Account Descriptions	Account Number	2011													
		Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11	Opening Principal Amounts as of Jan-1-12	Transactions Debit / (Credit) during 2012 excluding interest and adjustments [3]	Board-Approved Disposition during 2012
Group 1 Accounts															
LV Variance Account	1550	$0				$0	$0				$0	$0		
RSVA - Wholesale Market Service Charge	1580	-$280,612	-$76,144			-$356,756	$32,788	-$4,630			$28,158	-$356,756	-$95,339	-$280,612
RSVA - Retail Transmission Network Charge	1584	$12,889	$17,336			$30,225	-$12,957	$420			-$12,537	$30,225	$1,186	$12,889
RSVA - Retail Transmission Connection Charge	1586	-$404,911	-$3,146			-$408,057	-$120,532	-$6,010			-$126,542	-$408,057	$2,391	-$404,911
RSVA - Power (excluding Global Adjustment)	1588	$436,070	-$9,401			$426,669	$28,050	$9,130			$37,180	$426,669	$49,300	$436,070
RSVA - Global Adjustment	1589	-$35,115	$44,497		-$350,320	-$340,938	-$1,590	-$853			-$2,443	-$340,938	-$219,720	-$35,115
Recovery of Regulatory Asset Balances	1590	-$34,527				-$34,527	-$2,822	-$508			-$3,330	-$34,527		-$34,528
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0	$0		
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$306,206	-$26,858	$0	-$350,320	-$683,384	-$77,063	-$2,451	$0	$0	-$79,514	-$683,384	-$262,182	-$306,207
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$271,091	-$71,355	$0	$0	-$342,446	-$75,473	-$1,598	$0	$0	-$77,071	-$342,446	-$42,462	-$271,092
RSVA - Global Adjustment	**1589**	-$35,115	$44,497	$0	-$350,320	-$340,938	-$1,590	-$853	$0	$0	-$2,443	-$340,938	-$219,720	-$35,115
Group 2 Accounts															
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$6,914				$6,914	$1,171	$113			$1,284	$6,914		
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$332	$15,000			$15,332	$3	$5			$7	$15,332	$11,000	
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0	$0		
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0		
Misc. Deferred Debits	1525	$0	$2,087			$2,087	$0	$183			$183	$2,087		$2,087
Renewable Generation Connection Capital Deferral Account	1531	$4,320				$4,320	$23	$64			$86	$4,320		
Renewable Generation Connection OM&A Deferral Account	1532	$0				$0	$0				$0	$0		
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0	$0		
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0		
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0		
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0		
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0		
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0		
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0		
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0		
RSVA - One-time	1582	$4,256				$4,256	$2,378	$63			$2,440	$4,256		
Other Deferred Credits	2425	$0			-$3,072	-$3,072	$0				$0	-$3,072	-$3,072	
Group 2 Sub-Total		$15,822	$17,087	$0	-$3,072	$29,837	$3,573	$427	$0	$0	$4,001	$29,837	$7,928	$2,087
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0	$0	-$25,203	-$25,203
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0	$0		
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0	$0		
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$290,384	-$9,771	$0	-$353,392	-$653,547	-$73,490	-$2,024	$0	$0	-$75,513	-$653,547	-$279,457	-$329,323

Account Descriptions	Account Number	2010									
		Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
LRAM Variance Account	1568					$0					$0
Total including Account 1568		$6,914	$8,908	$0	-$306,206	-$290,384	$1,115	$2,458	$0	-$77,063	-$73,490
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[10]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[10]	1556	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[9]	1575										
Accounting Changes Under CGAAP Balance + Return Component[9]	1576										
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$0				$0	$0				$0
Disposition and Recovery of Regulatory Balances[7]	1595	$0				$0	$0				$0

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Deferral/Variance Ac
for 2014 I

Account Descriptions	Account Number	2010									
		Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0			-$280,612	-$280,612	$0			$32,788	$32,788
RSVA - Retail Transmission Network Charge	1584	$0			$12,889	$12,889	$0			-$12,957	-$12,957
RSVA - Retail Transmission Connection Charge	1586	$0			-$404,911	-$404,911	$0			-$120,532	-$120,532
RSVA - Power (excluding Global Adjustment)	1588	$0			$436,070	$436,070	$0			$28,050	$28,050
RSVA - Global Adjustment	1589	$0			-$35,115	-$35,115	$0			-$1,590	-$1,590
Recovery of Regulatory Asset Balances	1590	$0			-$34,527	-$34,527	$0			-$2,822	-$2,822
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[7]	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	-$306,206	-$306,206	$0	$0	$0	-$77,063	-$77,063
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	-$271,091	-$271,091	$0	$0	$0	-$75,473	-$75,473
RSVA - Global Adjustment	**1589**	$0	$0	$0	-$35,115	-$35,115	$0	$0	$0	-$1,590	-$1,590
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$6,914				$6,914	$1,115	$55			$1,171
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0	$332			$332	$0	$3			$3
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Renewable Generation Connection Capital Deferral Account	1531	$0	$4,320			$4,320	$0	$23			$23
Renewable Generation Connection OM&A Deferral Account	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567					$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0	$4,256			$4,256	$0	$2,378			$2,378
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$6,914	$8,908	$0	$0	$15,822	$1,115	$2,458	$0	$0	$3,573
Deferred Payments in Lieu of Taxes	1562	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$0				$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$6,914	$8,908	$0	-$306,206	-$290,384	$1,115	$2,458	$0	-$77,063	-$73,490

APPENDIX B

FORT FRANCES POWER CORPORATION

2011 OPA FINAL EVALUATION REPORT

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2011 Results Report.

Despite some of the inertial challenges in 2011 with program start up, on average, year one province-wide forecasts were met and the year finished out with strong momentum which continues to build 2012. There are still challenges for LDCs of all sizes and we are committed to ensuring LDCs are successful in meeting their objectives. We look forward to further dialogue to discover opportunities to improve the current program suite with local program opportunities, best practices and successes to better reach our customers in the years to come.

This report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. Between the draft and final reports several improvements were made to improve clarity and transparency based on feedback provided by LDCs, such as: the addition of a glossary tab, total adjustments to savings are now broken out into both the realization rate and net-to-gross ratio for both peak demand and energy savings and modifications were made to the methodology tab. We invite you to continue to provide your feedback.

All results are now considered final for 2011. Any additional 2011 program activity not captured will be reported in the Final 2012 Results Report. Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2012.

Sincerely,
Andrew Pride

Table of Contents

Summary	Provides a "snapshot" of your LDC's OPA-Contracted Province-Wide Program performance in 2011: progress to target using 2 scenarios, sector breakdown and progress against the LDC community.
LDC-Specific Data: table formats, section references and table numbers align with the OEB Reporting Template	
2.3 Results Participation - LDC	Breakdown of initiative-level participation in 2011 for your LDC.
2.5.1 Evaluation Findings	Provides a summary of the province-wide evaluation findings for each initiative and highlights which initiatives were not evaluated.
2.5.2 Results - LDC	Provides LDC-specific initiative-level results (net and gross peak demand and energy savings, realization rates, net-to-gross ratios and how each initiative contributes to target)
3.1.1 Summary - LDC	Provides a portfolio level view of achievement towards your OEB targets in 2011. Contains space to input LDC-specific progress to milestones set out in your CDM Strategy.
Province-Wide Data: LDC performance in aggregate (province-wide results)	
Provincial - Participation	Breakdown of initiative-level participation in 2011 for the province.
Provincial - Results	Provides province-wide initiative-level results (net and gross peak demand and energy savings, realization rates, net-to-gross ratios and how each initiative contributes to target)
Provincial - Progress Summary	Provides a portfolio level view of provincial achievement towards province-wide OEB targets in 2011.
Methodology	Provides key equations, notes and an initiative-level breakdown of: how savings are attributed to LDCs, when the savings are considered to 'start' (i.e. what period the savings are attributed to) and how the savings are calculated.
Reference Tables	Provides the sector mapping used for Retrofit and the allocation methodology table used in the consumer program when
Glossary	Contains definitions for terms used throughout the report.

OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

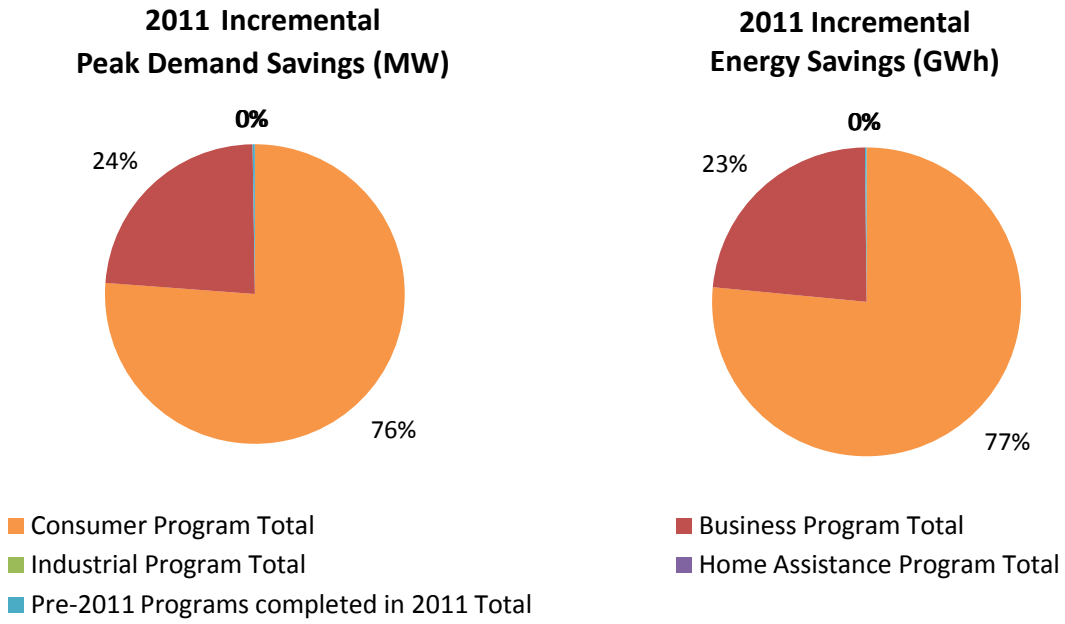
LDC: Fort Frances Power Corporation

FINAL 2011 Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.0	**2.3%**	**2.4%**
Net Cumulative Energy Savings (GWh)	0.1	**11.7%**	**11.7%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector



Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

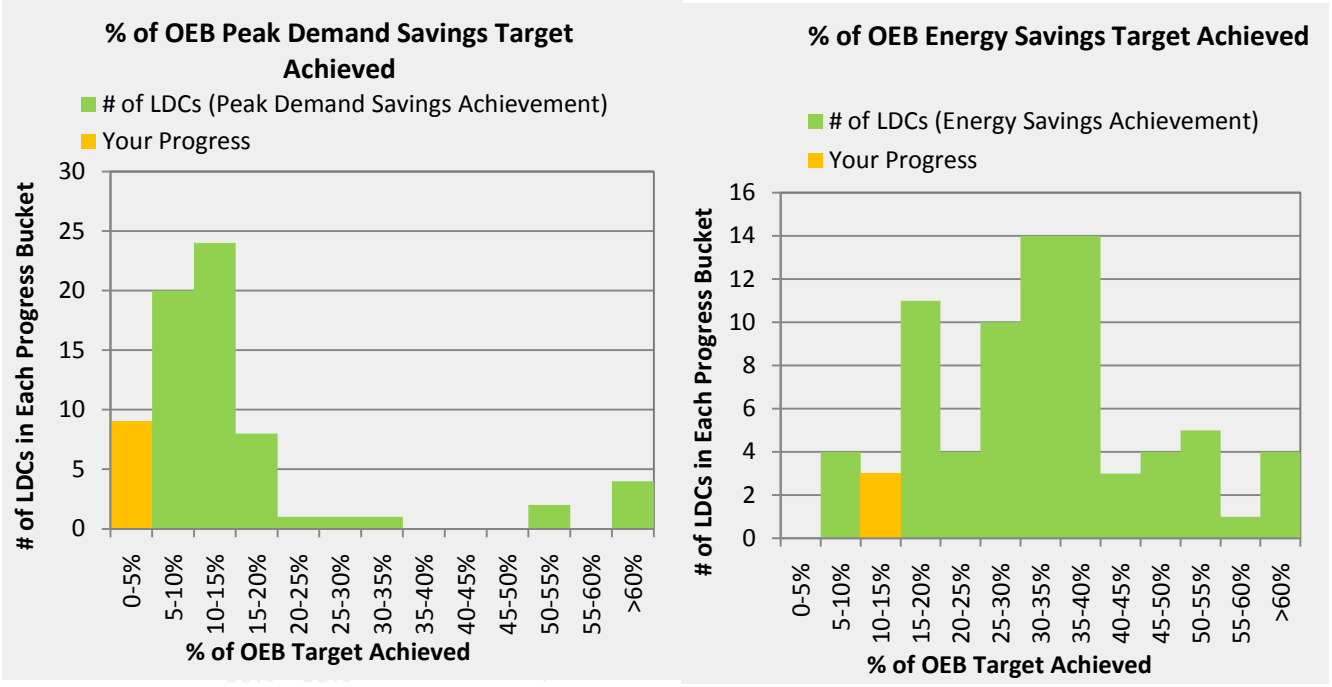


Table 1: Participation[1]

#	Initiative	Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	59
2	Appliance Exchange	Appliances	14
3	HVAC Incentives	Equipment	11
4	Conservation Instant Coupon Booklet	Products	494
5	Bi-Annual Retailer Event	Products	866
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	0
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	1
10	Direct Install Lighting	Projects	0
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	0
14	Commercial Demand Response (part of the Residential program schedule)	Devices	0
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	0
20	Demand Response 3	Facilities	0
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	0
23	High Performance New Construction	Projects	0
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

[1] *Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

Table 3: OPA Province-Wide Evaluation Findings

#	Initiative	OPA Province-Wide Key Evaluation Findings
Consumer Program		

1	Appliance Retirement	* Overall participation continues to decline year over year
		  * Participation declined 17% from 2010 (from over 67,000 units in 2010 to over 56,000 units in 2011)
		* 97% of net resource savings achieved through the home pick-up stream
		  * Measure Breakdown: 66% refrigerators, 30% freezers, 4% Dehumidifiers and window air conditioners
		* 3% of net resource savings achieved through the Retailer pick-up stream
		  * Measure Breakdown: 90% refrigerators, 10% freezers
		* Net-to-Gross ratio for the initiative was 50%
		  * Measure-level free ridership ranges from 82% for the retailer pick-up stream to 49% for the home pick-up stream
		  * Measure-level spillover ranges from 3.7% for the retailer pick-up stream to 1.7% for the home pick-up stream

2	Appliance Exchange	* Overall eligible units exchanged declined by 36% from 2010 (from over 5,700 units in 2010 to
		  * Measure Breakdown: 75% window air conditioners, 25% dehumidifiers
		* Dehumidifiers and window air conditioners contributed almost equally to the net energy
		  * Dehumidifiers provide more than three times the energy savings per unit than window air conditioners
		* Window air conditioners contributed to 64% of the net peak demand savings achieved
		* Approximately 96% of consumers reported having replaced their exchanged units (as opposed to retiring the unit)
		* Net-to-Gross ratio for the initiative is consistent with previous evaluations (51.5%)

3	HVAC Incentives	* Total air conditioner and furnace installations increased by 14% (from over 95,800 units in 2010 to over 111,500 units in 2011)
		  * Measure Breakdown: 64% furnaces, 10% tier 1 air conditioners (SEER 14.5) and 26% tier 2 air conditioners (SEER 15)
		  * Measure breakdown did not change from 2010 to 2011
		* The HVAC Incentives initiative continues to deliver the majority of both the energy (45%) and demand (83%) savings in the consumer program
		  * Furnaces accounted for over 91% of energy savings achieved for this initiative
		* Net-to-Gross ratio for the initiative was 17% higher than 2010 (from 43% in 2010 to 60% in
		  * Increase due in part to the removal of programmable thermostats from the program, and an increase in the net-to-gross ratio for both Furnaces and Tier 2 air conditioners (SEER 15)

4	Conservation Instant Coupon Booklet	* Customers redeemed nearly 210,000 coupons, translating to nearly 560,000 products
		  * Majority of coupons redeemed were downloadable (~40%) or LDC-branded (~35%)
		  * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (37%), followed by multi-packs of specialty CFLs (17%)
		* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings
		* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed

#	Initiative	OPA Province-Wide Key Evaluation Findings
5	Bi-Annual Retailer Event	* Customers redeemed nearly 370,000 coupons, translating to over 870,000 products * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (49%), followed by multi-packs of specialty CFLs (16%) * Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings * Standard CFLs and heavy duty outdoor timers were reintroduced to the initiative in 2011 and contributed more than 64% of the initiative's 2011 net annual energy savings * While the volume of coupons redeemed for heavy duty outdoor timers was relatively small (less than 1%), the measure accounted for 10% of net annual savings due to high per unit savings * Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed.
6	Retailer Co-op	* Initiative was not evaluated in 2011 due to low uptake. Verified Bi-Annual Retailer Event per unit assumptions and free-ridership rates were used to calculate net resource savings
7	Residential Demand Response	* Approximately 20,000 new devices were installed in 2011 * 99% of the new devices enrolled controlled residential central AC (CAC) * 2011 only saw 1 atypical event (in both weather and timing) that had limited participation * The ex ante impact developed through the 2009/2010 evaluations was maintained for 2011; residential CAC: 0.56 kW/device, commercial CAC: 0.64 kW/device, and Electric Water Heaters: 0.30 kW/device
8	Residential New Construction	* Initiative was not evaluated in 2011 due to limited uptake * Business case assumptions were used to calculate savings
Business Program		
9	Efficiency: Equipment Replacement	* Gross verified energy savings were boosted by lighting projects in the prescriptive and * Lighting projects overall were determined to have a realization rate of 112%; 116% when including interactive energy changes * On average, the evaluation found high realization rates as a result of both longer operating hours and larger wattage reductions than initial assumptions * Low realization rates for engineered lighting projects due to overstated operating hour assumptions * Custom non-lighting projects suffered from process issues such as: the absence of required M&V plans, the use of inappropriate assumptions , and the lack of adherence to the M&V plan * The final realization rate for summer peak demand was 94% * 84% was a result of different methodologies used to calculate peak demand savings * 10% due to the benefits from reduced air conditioning load in lighting retrofits * Overall net-to-gross ratios in the low 70's represent an improvement over the 2009 and Strict eligibility requirements and improvements in the pre-approval process contributed to the improvement in net-to-gross ratios
		* Though overall performance is above expectations, participation continues to decline year over year as the initiative reaches maturity * 70% of province-wide resource savings persist to 2014

#	Initiative	OPA Province-Wide Key Evaluation Findings
10	Direct Install Lighting	* Over 35% of the projects for 2011 included at least one CFL measure * Resource savings from CFLs in the commercial sector only persist for the industry standard of 3 years * Since 2009 the overall realization rate for this program has improved * 2011 evaluation recorded the highest energy realization rate to date at 89.5% * The hours of use values were held constant from the 2010 evaluation and continue to be the main driver of energy realization rate * Lights installed in "as needed" areas (e.g., bathrooms, storage areas) were determined to have very low realization rates due to the difference in actual energy saved vs. reported savings
11	Existing Building Commissioning Incentive	* Initiative was not evaluated in 2011, no completed projects in 2011
12	New Construction and Major Renovation Incentive	* Initiative was not evaluated in 2011 due to low uptake * Assumptions used are consistent with preliminary reporting based on the 2010 Evaluation findings and consultation with the C&I Work Group (100% realization rate and 50% net-to-gross ratio)
13	Energy Audit	* The evaluation is ongoing. The sample size for 2011 was too small to draw reliable conclusions.
14	Commercial Demand Response (part of the Residential program schedule)	* See residential demand response (#7)
15	Demand Response 3 (part of the Industrial program schedule)	* See Demand Response 3 (#20)
Industrial Program		
16	Process & System Upgrades	* Initiative was not evaluated in 2011, no completed projects in 2011
17	Monitoring & Targeting	* Initiative was not evaluated in 2011, no completed projects in 2011
18	Energy Manager	* Initiative was not evaluated in 2011, no completed projects in 2011
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	* See Efficiency: Equipment Replacement (#9)
20	Demand Response 3	* Program performance for Tier 1 customers increased with DR-3 participants providing 75% * Industrial customers outperform commercial customers by provide 84% and 76% of contracted MW, respectively * Program continues to diversify but still remains heavily concentrated with less than 5% of

#	Initiative	OPA Province-Wide Key Evaluation Findings
		* By increasing the number of contributors in each settlement account and implementation of the new baseline methodology the performance of the program is expected to increase
Home Assistance Program		
21	Home Assistance Program	* Initiative was not evaluated in 2011 due to low uptake * Business Case assumptions were used to calculate savings
Pre-2011 Programs completed in 2011		
22	Electricity Retrofit Incentive Program	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (multifamily buildings 99% realization rate and 62% net-to-gross ratio and C&I buildings 77% realization rate and 52% net-to-gross ratio)
23	High Performance New Construction	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (realization rate of 100% and net-to-gross ratio of 50%)
24	Toronto Comprehensive	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
25	Multifamily Energy Efficiency Rebates	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
26	Data Centre Incentive Program	* Initiative was not evaluated
27	EnWin Green Suites	* Initiative was not evaluated

Table 5: Summarized Program Results

Program	Gross Savings			Net Savings	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)		Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program Total	18	107,907		11	81,974
Business Program Total	5	32,687		4	24,977
Industrial Program Total	0	0		0	0
Home Assistance Program Total	0	0		0	0
Pre-2011 Programs completed in 2011 Total	0	364		0	182
Total OPA Contracted Province-Wide CDM Programs	**23**	**140,959**		**15**	**107,133**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	7	49,283	51%	52%	4	25,562
2	Appliance Exchange	100%	100%	3	3,277	52%	52%	1	1,689
3	HVAC Incentives	100%	100%	6	11,810	59%	59%	4	7,002
4	Conservation Instant Coupon Booklet	100%	100%	1	16,780	114%	111%	1	18,489
5	Bi-Annual Retailer Event	100%	100%	1	26,757	113%	110%	2	29,232
6	Retailer Co-op	-	-	0	0	-	-	0	0
7	Residential Demand Response	0%	0%	0	0	-	-	0	0
8	Residential New Construction	-	-	0	0	-	-	0	0
Business Program									
9	Efficiency: Equipment Replacement	93%	135%	5	32,687	75%	76%	4	24,977
10	Direct Install Lighting	-	-	0	0	-	-	0	0
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0
12	New Construction and Major Renovation Incentive	-	-	0	0	-	-	0	0
13	Energy Audit	-	-	0	0	-	-	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	0	0	-	-	0	0
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	0	0	n/a	n/a	0	0
Industrial Program									
16	Process & System Upgrades	-	-	0	0	-	-	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0
18	Energy Manager	-	-	0	0	-	-	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	-	-	0	0	-	-	0	0
20	Demand Response 3	84%	100%	0	0	n/a	n/a	0	0
Home Assistance Program									
21	Home Assistance Program	-	-	0	0	-	-	0	0
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	-	-	0	0	-	-	0	0
23	High Performance New Construction	100%	100%	0	364	50%	50%	0	182
24	Toronto Comprehensive	-	-	0	0	-	-	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	10	327,057
Business Program Total	4	99,907
Industrial Program Total	0	0
Home Assistance Program Total	0	0
Pre-2011 Programs completed in 2011 Total	0	729
Total OPA Contracted Province-Wide CDM Programs	**14**	**427,693**

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	4	102,247
2	Appliance Exchange	0	5,917
3	HVAC Incentives	4	28,008
4	Conservation Instant Coupon Booklet	1	73,956
5	Bi-Annual Retailer Event	2	116,929
6	Retailer Co-op	0	0
7	Residential Demand Response	0	0
8	Residential New Construction	0	0
Business Program			
9	Efficiency: Equipment Replacement	4	99,907
10	Direct Install Lighting	0	0
11	Existing Building Commissioning Incentive	0	0
12	New Construction and Major Renovation Incentive	0	0
13	Energy Audit	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0	0
15	Demand Response 3 (part of the Industrial program schedule)	0	0
Industrial Program			
16	Process & System Upgrades	0	0
17	Monitoring & Targeting	0	0
18	Energy Manager	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	0	0
20	Demand Response 3	0	0
Home Assistance Program			
21	Home Assistance Program	0	0
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	0	0
23	High Performance New Construction	0	729
24	Toronto Comprehensive	0	0
25	Multifamily Energy Efficiency Rebates	0	0
26	Data Centre Incentive Program	0	0
27	EnWin Green Suites	0	0

Assumes demand response resources have a persistence of 1 year

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Yellow cells are intended for the LDC to input information to complete their OEB Reporting Template.

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.01	0.01	0.01	0.01
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.01
Fort Frances Power Corporation 2014 Annual CDM Capacity Target:				0.61
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				2.30%
LDC Milestone submitted for 2011				-%
Variance				

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.11	0.11	0.11	0.11	0.43
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					0.43
Fort Frances Power Corporation 2011-2014 Cumulative CDM Energy Target:					3.64
Verified Portion of Cumulative Energy Target Achieved (%):					11.75%
LDC Milestone submitted for 2011					-%
Variance					

Table P1: Province-Wide Participation

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	56,110
2	Appliance Exchange	Appliances	3,688
3	HVAC Incentives	Equipment	111,587
4	Conservation Instant Coupon Booklet	Products[4]	559,462
5	Bi-Annual Retailer Event	Products[5]	870,332
6	Retailer Co-op	Products	152
7	Residential Demand Response	Devices	19,577
8	Residential New Construction	Houses	7
Business Program			
9	Efficiency: Equipment Replacement	Projects	2,516
10	Direct Installed Lighting	Projects	20,297
11	Existing Building Commissioning Incentive	Buildings	-
12	New Construction and Major Renovation Incentive	Buildings	10
13	Energy Audit	Audits	103
14	Commercial Demand Response (part of the Residential program schedule)	Devices	264
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	148
Industrial Program			
16	Process & System Upgrades[2]	Projects	-
17	Monitoring & Targeting[2]	Projects	-
18	Energy Manager[2 3]	Managers	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)[1]	Projects	433
20	Demand Response 3	Facilities	134
Home Assistance Program			
21	Home Assistance Program	Homes	46
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	2,023
23	High Performance New Construction	Projects	145
24	Toronto Comprehensive	Projects	553
25	Multifamily Energy Efficiency Rebates	Projects	110
26	Data Centre Incentive Program	Projects	5
27	EnWin Green Suites	Projects	3

[2] Results are based on completed incentive projects (see "Methodology" tab for more information)

[3] Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers with completed projects

[4] 209,693 valid coupons redeemed

[5] 369,446 valid coupons redeemed

Table P2: Province-Wide Results

Program	Gross Savings			Net Savings	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)		Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program Total	73,757	192,379,633		49,123	133,519,668
Business Program Total	78,048	251,304,448		64,594	198,124,227
Industrial Program Total	68,648	41,493,145		57,099	31,947,577
Home Assistance Program Total	4	56,119		2	39,283
Pre-2011 Programs completed in 2011 Total	87,169	460,822,079		44,833	241,853,020
Total OPA Contracted Province-Wide CDM Programs	**307,626**	**946,055,425**		**215,651**	**605,483,775**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	6,750	45,971,627	51%	51%	3,299	23,005,812
2	Appliance Exchange	100%	100%	719	873,531	51%	51%	371	450,187
3	HVAC Incentives	100%	100%	53,209	99,413,430	60%	60%	32,037	59,437,670
4	Conservation Instant Coupon Booklet	100%	100%	1,184	19,192,453	114%	111%	1,344	21,211,537
5	Bi-Annual Retailer Event	100%	100%	1,504	26,899,265	112%	110%	1,681	29,387,468
6	Retailer Co-op	100%	100%	0	3,917	68%	68%	0	2,652
7	Residential Demand Response	n/a	n/a	10,390	23,597	n/a	n/a	10,390	23,597
8	Residential New Construction	100%	100%	0	1,813	41%	41%	0	743
Business Program									
9	Efficiency: Equipment Replacement	106%	91%	34,201	184,070,265	72%	74%	24,467	136,002,258
10	Direct Installed Lighting	108%	93%	22,155	65,777,197	108%	93%	23,724	61,076,701
11	Existing Building Commissioning Incentive	-	-	-	-	-	-	-	-
12	New Construction and Major Renovation Incentive	50%	50%	247	823,434	50%	50%	123	411,717
13	Energy Audit	-	-	-	-	-	-	-	-
14	Commercial Demand Response (part of the Residential program schedule)	n/a	n/a	55	131	n/a	n/a	55	131
15	Demand Response 3 (part of the Industrial program schedule)	76%	n/a	21,390	633,421	n/a	n/a	16,224	633,421
Industrial Program									
16	Process & System Upgrades	-	-	-	-	-	-	-	-
17	Monitoring & Targeting	-	-	-	-	-	-	-	-
18	Energy Manager	-	-	-	-	-	-	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	111%	91%	6,372	38,412,408	72%	75%	4,615	28,866,840
20	Demand Response 3	84%	n/a	62,276	3,080,737	n/a	n/a	52,484	3,080,737
Home Assistance Program									
21	Home Assistance Program	100%	100%	4	56,119	70%	70%	2	39,283
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	80%	80%	40,418	223,956,390	54%	54%	21,550	120,492,549
23	High Performance New Construction	100%	100%	10,197	52,371,183	49%	49%	5,098	26,185,591
24	Toronto Comprehensive	113%	113%	33,467	174,070,574	50%	52%	15,805	86,964,886
25	Multifamily Energy Efficiency Rebates	93%	93%	2,553	9,774,792	78%	78%	1,981	7,595,683
26	Data Centre Incentive Program	100%	100%	81	533,038	100%	100%	81	533,038
27	EnWin Green Suites	100%	100%	453	116,102	70%	70%	317	81,272

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	38,405	534,017,835
Business Program Total	41,048	767,657,790
Industrial Program Total	4,613	118,543,019
Home Assistance Program Total	2	157,134
Pre-2011 Programs completed in 2011 Total	44,833	967,412,079
Total OPA Contracted Province-Wide CDM Programs	**128,901**	**2,387,787,856**

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	3,160	91,903,303
2	Appliance Exchange	181	1,930,651
3	HVAC Incentives	32,037	237,750,681
4	Conservation Instant Coupon Booklet	1,344	84,846,148
5	Bi-Annual Retailer Event	1,681	117,549,874
6	Retailer Co-op	0	10,607
7	Residential Demand Response	0	23,597
8	Residential New Construction	0	2,973
Business Program			
9	Efficiency: Equipment Replacement	24,438	543,856,392
10	Direct Installed Lighting	16,486	221,520,977
11	Existing Building Commissioning Incentive	-	-
12	New Construction and Major Renovation Incentive	123	1,646,869
13	Energy Audit	-	-
14	Commercial Demand Response (part of the Residential program schedule)	0	131
15	Demand Response 3 (part of the Industrial program schedule)	0	633,421
Industrial Program			
16	Process & System Upgrades	-	-
17	Monitoring & Targeting	-	-
18	Energy Manager	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	4,613	115,462,282
20	Demand Response 3	0	3,080,737
Home Assistance Program			
21	Home Assistance Program	2	157,134
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	21,550	481,970,197
23	High Performance New Construction	5,098	104,742,366
24	Toronto Comprehensive	15,805	347,859,545
25	Multifamily Energy Efficiency Rebates	1,981	30,382,733
26	Data Centre Incentive Program	81	2,132,152
27	EnWin Green Suites	317	325,086

Assumes demand response resources have a persistence of 1 year

Summary - Provincial Progress

Table P3: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	215.7	136.4	135.7	128.9
2012				
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				128.9
2014 Annual CDM Capacity Target				1,330
Verified Peak Demand Savings Target Achieved - 2011 (%):				9.69%

Table P4: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	605.5	601.6	599.6	580.9	2,388
2012					0
2013					0
2014					0
Verified Net Cumulative Energy Savings 2011-2014:					2,388
2011-2014 Cumulative CDM Energy Target:					6,000
Verified Portion of Energy Target Achieved - 2011 (%):					39.79%

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011				

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%

Hydro One Networks Inc.	30.0%
Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

APPENDIX C

FORT FRANCES POWER COPORATION

2012 OPA FINAL EVALUATION REPORT

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2012 Results Report. We have seen a 39% increase in energy savings for our new province-wide 2011-2014 suite of saveONenergy initiatives. Overall progress to targets is moving up with 29% of demand and 65% of energy savings achieved. Many LDCs, both large and small, continue to stay on track to meet or exceed their OEB targets. Conservation programs continue to be a valuable and cost effective resource for customers across the province, over the past two years the program cost to consumers remains within 3 cents per kWh.

Further to programmatic savings, capability building efforts launched in 2011 are yielding healthy enabled savings through Embedded Energy Managers and Audit initiative projects. The strong momentum continues in 2013.

We remain committed to ensuring LDCs are successful in meeting their objectives and our collective efforts to date have improved the current program suite by offering more local program opportunities, implementing a new expedited change management process, and enhancing incentives to make it easier for customers to participate in programs. We invite you to continue to provide your feedback to us and to celebrate our successes as we move forward.

The format of this report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. All results are now considered final for 2012. Any additional 2012 program activity not captured will be reported in the Final 2013 Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year.

Sincerely,



Andrew Pride

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OPA-Contracted Province-Wide CDM Programs FINAL 2012 Results

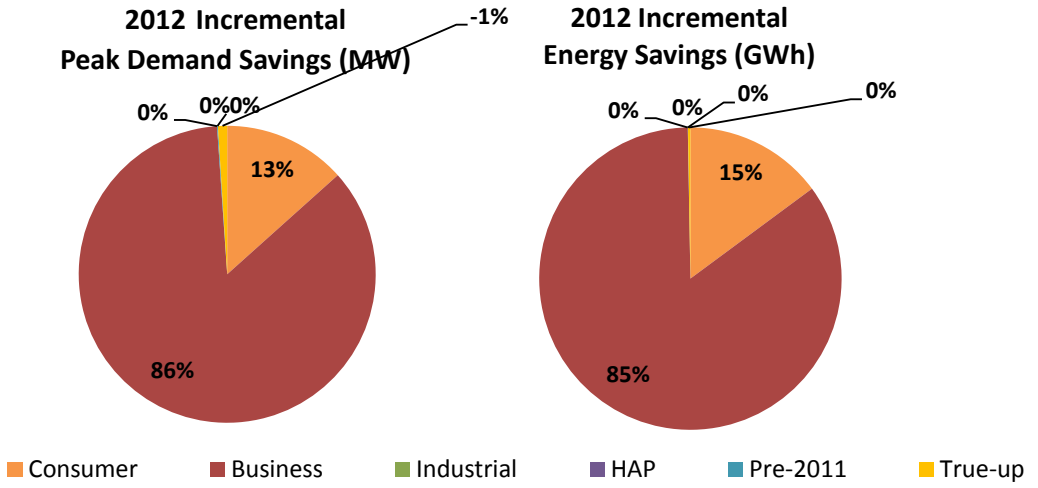
LDC: Fort Frances Power Corporation

FINAL 2012 Progress to Targets	2012 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.1	0.1	**21.0%**	**21.0%**
Net Energy Savings (GWh)	0.5	1.8	**49.4%**	**49.4%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector



Comparison: Your Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

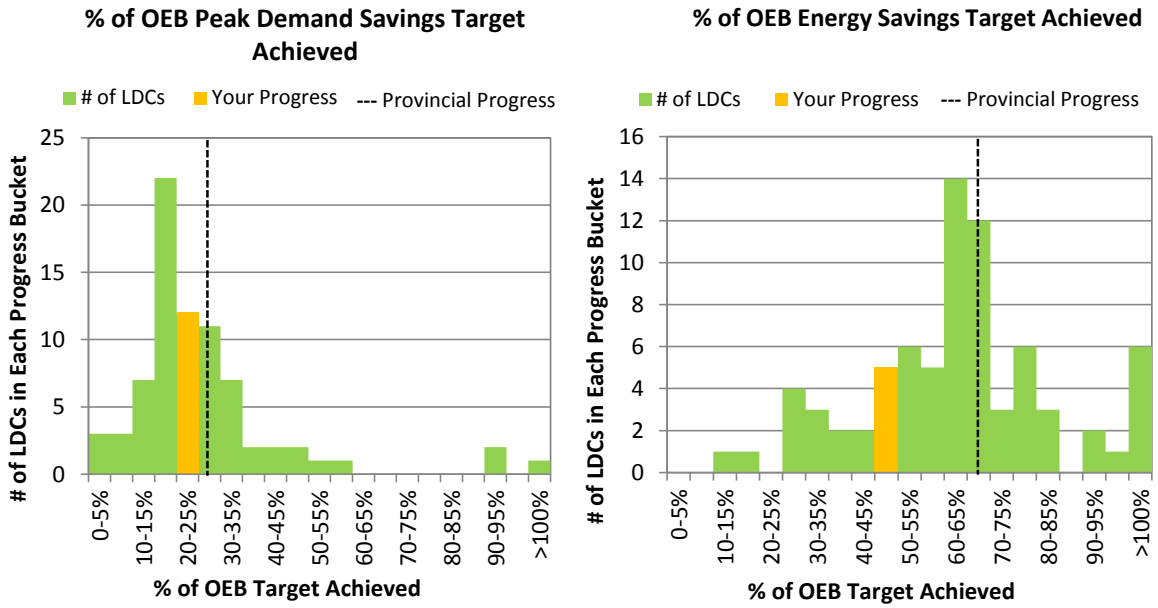


Table 1: **Fort Frances Power Corporation** Initiative and Program Level Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW) 2014	2011-2014 Net Cumulative Energy Savings (kWh) 2014
Consumer Program															
Appliance Retirement	Appliances	59	53			4	3			25,562	20,595			7	164,031
Appliance Exchange	Appliances	14	4			1	1			1,689	1,156			1	9,385
HVAC Incentives	Equipment	11	37			4	10			7,002	18,423			13	83,276
Conservation Instant Coupon Booklet	Items	494	31			1	0			18,489	1,391			1	78,129
Bi-Annual Retailer Event	Items	866	1,055			2	1			29,232	26,640			3	196,849
Retailer Co-op	Items	0	0			0	0			0	0			0	0
Residential Demand Response (switch/pstat)	Devices	0	0			0	0			0	0			0	0
Residential Demand Response (IHD)	Devices	0	0			0				0					
Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total						**11**	**16**			**81,974**	**68,204**			**26**	**531,670**
Business Program															
Retrofit	Projects	1	7			4	39			24,977	116,824			43	450,378
Direct Install Lighting	Projects	0	34			0	19			0	71,129			19	211,866
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	0	0			0	0			0	0			0	0
Energy Audit	Audits	0	8			0	41			0	201,410			41	604,230
Small Commercial Demand Response	Devices	0	0			0	0			0	0			0	0
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3	Facilities	0	0			0	0			0	0			0	0
Business Program Total						**4**	**100**			**24,977**	**389,363**			**103**	**1,266,475**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	0			0	0			0	0			0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3	Facilities	0	0			0	0			0	0			0	0
Industrial Program Total						**0**	**0**			**0**	**0**			**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0	0			0	0			0	0			0	0
Home Assistance Program Total						**0**	**0**			**0**	**0**			**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0			0	0			0	0			0	0
High Performance New Construction	Projects	0	0			0	0			182	109			0	1,055
Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total						**0**	**0**			**182**	**109**			**0**	**1,055**
Other															
Program Enabled Savings	Projects	0	0			0	0			0	0			0	0
Time-of-Use Savings	Homes														
Other Total							**0**				**0**			**0**	**0**
Adjustments to Previous Year's Verified Results							**-1**				**-84**			**-1**	**-337**
Energy Efficiency Total						**15**	**116**			**107,133**	**457,676**			**129**	**1,799,200**
Demand Response Total (Scenario 1)						**0**	**0**			**0**	**0**			**0**	**0**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**15**	**115**			**107,133**	**457,592**			**128**	**1,798,863**
													Full OEB Target:	**610**	**3,640,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**21.0%**	**49.4%**

Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 2: Adjustments to **Fort Frances Power Corporation** Verified Results due to Errors or Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-4				-1				-2,530				-1	-10,121
Conservation Instant Coupon Booklet	Items	8				0				274				0	1,097
Bi-Annual Retailer Event	Items	81				0				2,172				0	8,687
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	0				0				0				0	0
Consumer Program Total						**-1**				**-84**				**-1**	**-337**
Business Program															
Retrofit	Projects	0				0				0				0	0
Direct Install Lighting	Projects	0				0				0				0	0
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	0				0				0				0	0
Energy Audit	Audits	0				0				0				0	0
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**0**				**0**				**0**	**0**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0				0				0				0	0
High Performance New Construction	Projects	0				0				0				0	0
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**0**				**0**				**0**	**0**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**-1**				**-84**				**-1**	**-337**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3: Fort Frances Power Corporation Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.45				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.49				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		n/a				n/a				n/a				n/a		
Business Program																
Retrofit		0.93				0.76				1.07				0.78		
Direct Install Lighting		0.68				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		n/a				n/a				n/a				n/a		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		n/a				n/a				n/a				n/a		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		n/a				n/a				n/a				n/a		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		n/a				n/a				n/a				n/a		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.0	0.0	0.0	0.0
2012 - Verified		0.1	0.1	0.1
2013				
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.1
Fort Frances Power Corporation 2014 Annual CDM Capacity Target				0.6
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				21.0%

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.1	0.1	0.1	0.1	0.4
2012 - Verified		0.5	0.5	0.5	1.4
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					1.8
Fort Frances Power Corporation 2011-2014 Annual CDM Energy Target					3.6
Verified Portion of Cumulative Energy Target Achieved (%):					49.4%

*2011 energy adjustments included in cumulative energy savings.

Table 6: Province-Wide Initiatives and Program Level Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146			3,299	2,011			23,005,812	13,424,518			5,171	132,176,857
Appliance Exchange	Appliances	3,688	3,836			371	556			450,187	974,621			689	4,512,525
HVAC Incentives	Equipment	111,587	85,221			32,037	19,060			59,437,670	32,841,283			51,097	336,274,530
Conservation Instant Coupon Booklet	Items	559,462	30,891			1,344	230			21,211,537	1,398,202			1,575	89,040,754
Bi-Annual Retailer Event	Items	870,332	1,060,901			1,681	1,480			29,387,468	26,781,674			3,161	197,894,897
Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
Residential Demand Response (switch/pstat)*	Devices	19,550	98,388			10,947	49,038			24,870	359,408			0	384,279
Residential Demand Response (IHD)	Devices	0	49,689			0				0					
Residential New Construction	Homes	7	19			0	2			743	17,152			2	54,430
Consumer Program Total						**49,681**	**72,377**			**133,520,941**	**75,796,859**			**61,696**	**760,348,879**
Business Program															
Retrofit	Projects	2,516	5,605			24,467	61,147			136,002,258	314,922,468			84,018	1,480,647,459
Direct Install Lighting	Projects	20,297	18,494			23,724	15,284			61,076,701	57,345,798			31,181	391,072,869
Building Commissioning	Buildings	0	0			0	0			0	0			0	0
New Construction	Buildings	10	69			123	764			411,717	1,814,721			888	7,091,031
Energy Audit	Audits	103	280			0	1,450			0	7,049,351			1,450	21,148,054
Small Commercial Demand Response	Devices	132	294			84	187			157	1,068			0	1,224
Small Commercial Demand Response (IHD)	Devices	0	0			0				0				0	0
Demand Response 3*	Facilities	145	151			16,218	19,389			633,421	281,823			0	915,244
Business Program Total						**64,617**	**98,221**			**198,124,253**	**381,415,230**			**117,535**	**1,900,875,881**
Industrial Program															
Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
Energy Manager	Projects	0	39			0	1,086			0	7,372,108			1,086	22,116,324
Retrofit	Projects	433				4,615				28,866,840				4,613	115,462,282
Demand Response 3*	Facilities	124	185			52,484	74,056			3,080,737	1,784,712			0	4,865,449
Industrial Program Total						**57,098**	**75,141**			**31,947,577**	**9,156,820**			**5,699**	**142,444,054**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033			2	566			39,283	5,442,232			569	16,483,831
Home Assistance Program Total						**2**	**566**			**39,283**	**5,442,232**			**569**	**16,483,831**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
High Performance New Construction	Projects	145	69			5,098	3,251			26,185,591	11,901,944			8,349	140,448,197
Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
LDC Custom Programs	Projects	8	0			399	0			1,367,170	0			399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**			**243,251,550**	**11,901,944**			**48,195**	**1,008,712,030**
Other															
Program Enabled Savings	Projects	0	16			0	2,304			0	1,188,362			2,304	3,565,086
Time-of-Use Savings	Homes														
Other Total							**2,304**				**1,188,362**			**2,304**	**3,565,086**
Adjustments to Previous Year's Verified Results							**1,406**				**18,689,081**			**1,156**	**73,918,598**
Energy Efficiency Total						**136,610**	**109,191**			**603,144,419**	**482,474,435**			**235,998**	**3,826,263,564**
Demand Response Total (Scenario 1)						**79,733**	**142,670**			**3,739,185**	**2,427,011**			**0**	**6,166,196**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**			**606,883,604**	**503,590,526**			**237,154**	**3,906,348,358**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**17.8%**	**65.1%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Due to the limited timeframe of data, which didn't include the summer months, 2012 IHD results have been deemed inconclusive. The IHD line item on the 2012 annual report will be left blank. Once a full year of data is available (2013 evaluation), and the savings are quantified, 2012 results will be updated to reflect the quantified savings.

Table 7: Adjustments to **Province-Wide** Verified Results due to Errors & Omissions (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW) 2014	2011-2014 Net Cumulative Energy Savings (kWh) 2014
Consumer Program															
Appliance Retirement	Appliances	0				0				0				0	0
Appliance Exchange	Appliances	0				0				0				0	0
HVAC Incentives	Equipment	-18,866				-5,278				-9,721,817				-5,278	-38,887,267
Conservation Instant Coupon Booklet	Items	8,216				16				275,655				16	1,102,621
Bi-Annual Retailer Event	Items	81,817				108				2,183,391				108	8,733,563
Retailer Co-op	Items	0				0				0				0	0
Residential Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Residential Demand Response (IHD)	Devices	0				0				0				0	0
Residential New Construction	Homes	19				1				13,767				1	55,069
Consumer Program Total						**-5,153**				**-7,249,004**				**-5,153**	**-28,996,015**
Business Program															
Retrofit	Projects	303				3,204				16,216,165				3,083	64,398,674
Direct Install Lighting	Projects	444				501				1,250,388				372	4,624,945
Building Commissioning	Buildings	0				0				0				0	0
New Construction	Buildings	12				828				3,520,620				828	14,082,482
Energy Audit	Audits	93				481				2,341,392				481	9,365,567
Small Commercial Demand Response (switch/pstat)*	Devices	0				0				0				0	0
Small Commercial Demand Response (IHD)	Devices	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Business Program Total						**5,014**				**23,328,565**				**4,764**	**92,471,668**
Industrial Program															
Process & System Upgrades	Projects	0				0				0				0	0
Monitoring & Targeting	Projects	0				0				0				0	0
Energy Manager	Projects	0				0				0				0	0
Retrofit	Projects	0				0				0				0	0
Demand Response 3*	Facilities	0				0				0				0	0
Industrial Program Total						**0**				**0**				**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0				0				0				0	0
Home Assistance Program Total						**0**				**0**				**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12				138				545,536				138	2,182,145
High Performance New Construction	Projects	34				1,407				2,065,200				1,407	8,260,800
Toronto Comprehensive	Projects	0				0				0				0	0
Multifamily Energy Efficiency Rebates	Projects	0				0				0				0	0
LDC Custom Programs	Projects	0				0				0				0	0
Pre-2011 Programs completed in 2011 Total						**1,545**				**2,610,736**				**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	0				0				0				0	0
Time-of-Use Savings	Homes														
Other Total						**0**				**0**				**0**	**0**
Adjustments to Previous Year's Verified Results						**1,406**				**18,690,297**				**1,156**	**73,918,598**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement		1.00				0.46				1.00				0.47		
Appliance Exchange		1.00				0.52				1.00				0.52		
HVAC Incentives		1.00				0.50				1.00				0.49		
Conservation Instant Coupon Booklet		1.00				1.00				1.00				1.05		
Bi-Annual Retailer Event		1.00				0.91				1.00				0.92		
Retailer Co-op		n/a				n/a				n/a				n/a		
Residential Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Residential Demand Response (IHD)		n/a				n/a				n/a				n/a		
Residential New Construction		3.65				0.49				7.17				0.49		
Business Program																
Retrofit		0.93				0.75				1.05				0.76		
Direct Install Lighting		0.69				0.94				0.85				0.94		
Building Commissioning		n/a				n/a				n/a				n/a		
New Construction		0.98				0.49				0.99				0.49		
Energy Audit		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (switch/pstat)*		n/a				n/a				n/a				n/a		
Small Commercial Demand Response (IHD)		n/a				n/a				n/a				n/a		
Demand Response 3*		n/a				n/a				n/a				n/a		
Industrial Program																
Process & System Upgrades		n/a				n/a				n/a				n/a		
Monitoring & Targeting		n/a				n/a				n/a				n/a		
Energy Manager		1.16				0.90				1.16				0.90		
Retrofit																
Demand Response 3*		n/a				n/a				n/a				n/a		
Home Assistance Program																
Home Assistance Program		0.32				1.00				0.99				1.00		
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program		n/a				n/a				n/a				n/a		
High Performance New Construction		1.00				0.50				1.00				0.50		
Toronto Comprehensive		n/a				n/a				n/a				n/a		
Multifamily Energy Efficiency Rebates		n/a				n/a				n/a				n/a		
LDC Custom Programs		n/a				n/a				n/a				n/a		
Other																
Program Enabled Savings		1.06				1.00				2.26				1.00		
Time-of-Use Savings		n/a				n/a				n/a				n/a		

Summary - Provincial Progress

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012		253.3	109.8	108.2
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				237.2
2014 Annual CDM Capacity Target				1,330
Verified Peak Demand Savings Target Achieved - 2011 (%):				17.8%

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393
2012		503.6	498.4	492.6	1,513
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					3,906
2011-2014 Cumulative CDM Energy Target:					6,000
Verified Portion of Energy Target Achieved - 2011 (%):					65.1%

*2011 energy adjustments included in cumulative energy savings.

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings =** Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Engineered and Custom Projects	**Gross Savings =** Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
Demand Response	**Peak Demand: Gross Savings = Net Savings =** contracted MW at contributor level * Provincial contracted to ex ante ratio **Energy: Gross Savings = Net Savings =** provincial ex post energy savings * LDC proportion of total provincial contracted MW All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)
Adjustments to Previous Year's Verified Results	All errors and omissions from the prior years Final Annual Results report will be adjusted within this report. Any errors and ommissions with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2012 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; No completed projects in 2011 or 2012.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).