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BY E-MAIL

June 27, 2014

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Fort Frances Power Corporation
Application for Rates
Board Staff Submission
Board File No. EB-2013-0130

In accordance with Procedural Order No. 2 issued on May 21, 2014, please find attached the Board staff submission on the referenced application filed by Fort Frances Power Corporation.

Original Signed By

Martin Davies
Project Advisor, Electricity Rates & Accounting
Attachment

cc: Parties to EB-2013-0130 proceeding

2014 ELECTRICITY DISTRIBUTION RATES

Fort Frances Power Corporation

EB-2013-0130

STAFF SUBMISSION

June 27, 2014

INTRODUCTION

Fort Frances Power Corporation ("FFPC" or the "Applicant") is a licensed electricity distributor serving the Town of Fort Frances, which has approximately 3,777 customers. FFPC filed its complete 2014 rebasing application (the "Application") on February 14, 2014. FFPC requested approval of its proposed distribution rates and other charges effective May 1, 2014. FFPC's rates were declared interim effective May 1, 2014 in *Procedural Order No. 1 and Order for Interim Rates* issued by the Board on March 20, 2014. The Application was based on a future test year cost of service methodology.

The Vulnerable Energy Consumers' Coalition ("VECC") was granted intervenor status. The proceeding has been conducted through a written hearing.

This submission reflects observations and concerns which have arisen from Board staff's review of the pre-filed evidence and interrogatory and teleconference responses provided by FFPC, and are intended to assist the Board in evaluating the Application and in setting just and reasonable rates.

THE APPLICATION

FFPC requested a service revenue requirement of $1,989,765 (or a base revenue requirement of $1,881,732). Board staff notes that there may be some confusion as to whether or not FFPC updated the base revenue requirement during the course of the proceeding, but believes that $1,881,732 is the correct number.

The confusion stems from FFPC's response to a VECC teleconference question in April,[1] FFPC stated that it had updated its Other Operating Revenue for 2014 to reflect an additional $5,000 in the category of Sales and Water Power Revenues in 2014 which increased revenue offsets to $108,033 and which Board staff has reflected in the summary table below. However, Board staff notes that in response to a subsequent VECC teleconference question[2] in May, the Test year revenue offsets were shown as

[1] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on April 4, 2014 Filed on April 17, 2014,* p.16 QUESTION VECC #1

[2] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* p.26 7.6-VECC-41.

$103,033 which appears to exclude the $5,000 adjustment. Board staff has drafted this submission with the understanding that the numbers in the table below incorporating this adjustment represent the final requested service revenue requirement for 2014 rates.

FFPC also updated its stranded meter rate riders during the course of the proceeding (further discussion of this is in Section 9 Accounting of this submission) and, as such, there were some relatively small changes to the proposed rates from those filed in the original application. The proposed rates are set to recover a revenue deficiency of $459,007. The following is a breakdown of FFPC's 2014 test year revenue requirement:

FFPC 2014 Test Year Revenue Requirement		
OM&A Expenses	$	1,657,650
Amortization/Depreciation	$	197,074
Deemed Interest Expense	$	135,041
Service Revenue Requirement	$	1,989,765
Revenue Offsets	$	108,033
Base Revenue Requirement	$	1,881,732

Board staff invites FFPC to make any necessary clarifications/corrections to the above numbers in its reply submission.

1. Foundation

1.1 Does the planning (regional, infrastructure investment, asset management, etc.) undertaken by the applicant and outlined in the application support the appropriate management of the applicant's assets?

Background

FFPC stated that it had organized its Distribution System Plan (DSP) according to the expected format contained within the March 28, 2013 "Chapter 5 Consolidated Distribution System Plan Filing Requirements Guide". FFPC further stated that considerable additional subsections had been added to expand on relevant topics of discussion.

Discussion and Submission

Board staff notes that FFPC's DSP provides a comprehensive overview of its planning activities in the areas of regional planning, infrastructure investment and asset management. Board staff submits that the planning undertaken by FFPC and outlined in the Application, as clarified by interrogatory and teleconference responses, support the appropriate management of the applicant's assets (see discussion under section 4 Operational Effectiveness) for the Test year. Board staff also submits that the proposed revenue requirement, subject to the modifications proposed by staff in this submission, would provide FFPC with the appropriate resources for doing so.

1.2 Are the customer engagement activities undertaken by the applicant commensurate with the approvals requested in the application?

Background

FFPC stated that it is dedicated to providing services in a manner that responds to customer preferences and that during the summer of 2013, it conducted an extensive customer satisfaction survey that was instrumental in gauging satisfaction, identifying improvement opportunities and assessing future customer needs.

FFPC further stated that the feedback gathered has helped to shape its capital expenditures and to devote operational resources over the planning period, to align service offerings with the needs of its customer base.

FFPC stated that in response to the needs and requests identified by customers, it will be: (1) transitioning to true monthly billing, which means that while FFPC is already billing customers on a monthly basis, it will now be billing them for each actual month's consumption (e.g. September 1^{st} to 30^{th}), (2) offering a choice of electronic or paper billing, as well as granting access to consumption and billing data in 2014, and (3) investing in a mass customer contact system, as well as in an outage management system.

FFPC concluded that these investments will enable it to improve its ability to manage outages, as well as improve its ability to communicate directly with customers regarding important events such as outages. FFPC stated that with the help of this technology, customer communication will be conducted in an efficient and effective manner.

FFPC's customer engagement efforts also include plans to fill a new "Technical Customer Services Representative" position, to focus on continued customer and stakeholder engagement activities and to conduct customer education campaigns in local schools, at tradeshows, town hall meetings, as well as through standard media outlets.

Furthermore, FFPC stated, as a result of its customer engagement activities, a total of $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.

FFPC further stated that as a municipally owned distributor, it frequently utilizes Town Hall Meetings to update the general public regarding current industry events as well as to solicit feedback. FFPC plans to utilize Town Hall Meetings to keep the general public informed with respect to the present 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.

Discussion and Submission

Based on the customer engagement activities outlined above and considering that 2014 is a transitional year, Board staff submits that the customer engagement activities undertaken by FFPC are commensurate with the approvals requested in the Application. Board staff does have some concerns with FFPC's customer engagement activities as regards the capital program. These are outlined in Section 4 of this submission and relate to Board staff's view that FFPC should obtain more specific customer feedback on its next DSP.

2. Performance Measures

2.1 Does the applicant's performance in the areas of: (1) delivering on Board-approved plans from its most recent cost of service decision; (2) reliability performance; (3) service quality, and (4) efficiency benchmarking, support the application?

Background

FFPC has no Board-approved plans from its most recent cost of service decision, which was in 2006, other than the OM&A and capital spending approved at that time, against which to measure its performance.

FFPC expressed the concern that given the increased focus on distributor efficiency and the pressure to “bend the cost curve”, its unique operating circumstances which, in the view of FFPC, materially inflate OM&A costs, may not have been taken into account when establishing cost related performance measures. As such, FFPC stated it had a concern 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.

FFPC observed that the methodology contained in the Pacific Economic Group (“PEG”) Reporting that establishes the Board’s rate setting parameters and benchmarking under the renewed regulatory framework for Ontario’s electricity distributors, underscores the importance of ensuring “apples to apples” benchmarking across distributors. This in turn highlights the need for FFPC’s unique circumstances to be taken into consideration when establishing its performance measures.

FFPC expressed the belief 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 (the “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 stated that its OM&A costs essentially support three distinct business functions, which have increased FFPC’s scope and, as such, synergies from these arrangements are best measured at the total bill level which encompasses FFPC’s unique circumstances and operating strategy.

A Board staff interrogatory[3] asked FFPC to quantify to the extent possible the additional costs that it incurs that lead to what it sees as flawed OM&A cost data. FFPC’s response is summarized in the table below:

[3] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 4 Interrogatories May 22, 2014,* pp. 22-24. 4.2-Staff-14.

				$			
Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**Total**
Total OM&A	1,246,014	1,301,839	1,316,912	1,295,968	1,604,971	1,464,312	8,230,016
Less: 1905 Agreement Costs	53,514	72,669	65,300	59,428	61,568	91,688	404,167
Less: Transformer Station Costs	32,045	38,125	43,493	43,716	57,942	42,820	258,141
FFPC OM&A Distribution Only	1,160,455	1,191,045	1,208,119	1,192,824	1,485,461	1,329,804	7,567,708
Legal Costs	0	10,751	8,800	0	230	28,027	47,808
% Non Distribution OM&A	6.9	8.5	8.3	8.0	7.4	9.2	8.0
% Legal Costs	0	0.8	0.7	0	0.0	1.9	0.6
Annual Estimated Savings Due to Shared Services							
1905 Agreement Costs	$18,700						
Transformer Station	$19,200						

Board staff also asked FFPC in the same interrogatory[4] to elaborate on the statement that synergies from the referenced arrangements are best measured at the total bill level and to explain how this would impact FFPC's performance scores if they were adjusted in this fashion.

FFPC responded that it believed the fundamental measure for the success of an LDC's adopted business model is reflected in the total cost of electricity that consumers pay. FFPC expressed the belief that the "catch all" measure of good or bad business decisions, as well as good or bad business models, is ultimately reflected in the total bill which should be a cornerstone of any performance benchmarking analysis.

FFPC argued that a total bill analysis would suggest that it is among the top performers in the industry, but the Board's performance benchmarking initiatives have identified it to be a substandard performer.

FFPC expressed the belief that the reason for this disconnect is that its unique operating circumstances have not been recognized in any of the modelling exercises conducted to date. FFPC stated that it has chosen to operate its electrical distribution business in a more financially prudent manner than the industry norm as it has chosen to operate with no debt, to partner with neighbouring LDCs for the delivery of shared services, and to increase its business scope.

FFPC stated that its administration of the Agreement and High Voltage Transformer Station have not only increased its business scope, but has also increased its internal cost burden. FFPC suggested that if the Agreement and High Voltage Transformer

[4] *Ibid,* p. 26.

Station were managed by third parties (or in silos), its performance scores would be improved at the cost of its customers paying higher rates.

FFPC concluded that a fair assessment of its performance would be based upon its costs without the Agreement and the Transformation Station Costs or, alternatively, at the Total Bill level. However, taking into account all of the costs without acknowledging the Total Bill, as the current performance scores do, gives a skewed view of FFPC as an underperformer.

FFPC stated that it was seeking in this proceeding an order directing Board staff and FFPC to work with PEG to ensure that the calculations that support the scorecard and efficiency ratings for FFPC are adjusted to exclude capital and OM&A costs associated with the transformer station and the administration of the Agreement[5].

Discussion and Submission

Board staff notes that the breakdown of the costs provided by FFPC in its response to the Board staff interrogatory and summarized in the table above indicates that the costs in dispute are mostly in areas that would be incurred whether or not FFPC had the Agreement and/or the High Voltage Transformer Station matters to deal with, such as billing and collecting and Board of Directors/staffing costs. The shared savings costs appear to be similar in nature. The only exception to this appears to be the legal expenses which, as is shown in the table above, averaged only 0.6% of FFPC's total OM&A costs in the 2008 to 2013 period.

Board staff further notes that where the costs related to the transformer station are concerned, these types of costs are not unique to FFPC and would be removed by PEG as part of its adjustment process, as long as they had been placed in the proper accounts by FFPC. As such, Board staff is of the view that most of the concerns expressed by FFPC related to this matter either relate to costs that would have been incurred in the absence of FFPC's particular circumstances, or are already taken into account by the analysis used in determining the benchmarking categories. Accordingly, Board staff does not believe that it is necessary for the Board to provide the direction requested by FFPC upon this matter.

[5] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014*, p. 15, 4.2-Staff-42.

Board staff considers that FFPC's reliability performance and service quality support the Application, as discussed under Issue 4.1. While FFPC's efficiency benchmarking performance is below average, based on the Board's methodology, Board staff accepts that the beneficial effects of the Agreement offset this to some extent and considers that overall FFPC's performance supports the application.

3. Customer Focus

3.1 Are the applicant's proposed capital expenditures and operating expenses appropriately reflective of customer feedback and preferences?

Board staff's submissions on this issue are covered by those contained under Issue 1.2 relating to customer engagement.

4. Operational Effectiveness

4.1 Does the applicant's distribution system plan appropriately support continuous improvement in productivity, the attainment of system reliability and quality objectives, and the level of associated revenue requirement requested by the applicant?

Background

FFPC projects capital expenditures to be in the $660 to $700 thousand range in the 2015 to 2018 period in its DSP, as is shown below:[6]

[6] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 20, 2013, Exh 2/Tab3/Sch 1, p.4*

	Forecast Period (planned) ($000)				
	2014	**2015**	**2016**	**2017**	**2018**
CATEGORY					
System Access	422	40	20	45	12
System Renewal	254	419	504	531	361
System Service	49	142	60	58	15
General Plant	97	76	76	33	311
TOTAL EXPENDITURE	820	676	660	667	698

The historic changes in FFPC's capital spending, as compared to the forecast levels, are summarized in Appendix 1. The key point of note from this appendix is that FFPC's capital spending averaged about $269,000 in the 2006 to 2012 period, but is forecast to average about $704,000 in the 2014 to 2018 period which is close to a three-fold increase in the forecast period to what has been undertaken in recent years.

Discussion and Submission

Board staff's submissions on FFPC's proposed capital program are divided into two major categories, which are: (1) submissions on the proposed 2014 capital program, and (2) submissions on the feasibility of the proposed five-year DSP.

1. FFPC's 2014 Proposed Capital Program

Board staff notes that FFPC's proposed 2014 capital program is broken out into four categories in the above table. Board staff submissions are on the first two categories of System Access and System Renewal. Board staff accepts FFPC's proposals for the categories of System Service and General Plant.

a) System Access

i) Long Term Load Transfers

The largest expenditure in the 2014 capital program is $371,739 for the elimination of long term load transfers ("LTLT"). FFPC stated that it is the "geographic distributor" of 14 customers located in three pockets along the edge of the municipal boundaries that define FFPC's licensed distribution service territory. FFPC further stated that Section 6.5.4 of the Board's Distribution System Code ("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 making an application for changes to the licensed service areas of each distributor; or (b) make the necessary expansions to the geographic distributor's distribution system to connect the load transfer customer so as to service that customer directly.

FFPC noted that its 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 stated that it is planning to expand its distribution feeders in the necessary locations, to be able to service the customers directly.

FFPC stated that the proposed expenditure will also allow it to be able to distribute the benefits of the Agreement to the LTLT customers. FFPC explained that these benefits currently cannot be distributed to the LTLT customers, as the "physical distributor" (Hydro One Networks Inc.) is metering and billing them.

FFPC further stated that it has been formally approached by four of the LTLT customers over the last year requesting that they be connected to FFPC's distribution system.

FFPC stated that the completion of this project will unlock access to approximately 25.4% of its service territory that is not developed, while also offering considerably improved access for potential renewable generation facilities. A further benefit would be that the implementation of this project would provide an alternate supply of electricity in close proximity to the Fort Frances Airport, in the event of an emergency.

FFPC stated that it would commence construction upon receiving the Board's approval with completion targeted for December 31, 2014.

FFPC was asked in a Board staff interrogatory for a number of clarifications relating to this project.[7] FFPC confirmed that the 14 customers are located in FFPC's licensed service area and were described in FFPC's most recent Elimination of LTLT Plan which was filed with the Board on December 3, 2013. FFPC further confirmed that there is

[7] EB-2013-0130 *Fort Frances Power Corporation Response to Issues 1-3 Interrogatories May 22, 2014,* pp. 2-7.1.1-Staff-2.

currently no formal settlement process between Hydro One and FFPC concerning these customers.

FFPC was also asked to provide information on the status of its discussions with Hydro One about these customers and if it had not had such discussions, the basis for its belief that this project could be completed in 2014. FFPC responded as follows[8]:

> FFPC has had discussions with Hydro One Networks Inc. regarding the connection of these customers to FFPC, and in 2010 FFPC formally met with a Hydro One official to conduct a joint site visit of all fourteen (14) customer locations. During the joint site visit Hydro One confirmed that all fourteen (14) customers were located within the municipal boundaries of the Town of Fort Frances and as such are within FFPC's licensed distribution service territory.
>
> Following the site visit, FFPC was verbally informed that Hydro One's LTLT team is backlogged with projects and resolving this particular issue was assigned a low priority given the relatively small number of customers involved. Since this time, FFPC has approached Hydro One on several occasions but has not been able to receive a status update regarding this matter. Although FFPC has not received formal consent from Hydro One to proceed servicing these customers, FFPC understands that it has the authority with Board approval to extend its plant to connect to these customers.
>
> At this point in time, FFPC believes that it could extend its plant to thirteen (13) of the fourteen (14) customer by the end of 2014. One customer connection is complicated by FFPC having to cross a Canadian National Railroad (CNR) right-of-way (rail road tracks), and obtaining the necessary project clearances has been known to take up to a year. As such, FFPC cannot guarantee that it will be able to connect to this customer by the end of 2014; however, FFPC is committed to eliminating this issue as soon as possible.
>
> Alternately, FFPC is open to implementing this project in three annual phases, in the interest of smoothing capital expenditures, as this project represents a disproportionately large portion of FFPC's planned 2014 Capital Budget. As previously mentioned, FFPC has planned this work for 2014 to comply with the requirements of the DSC.

FFPC was asked by Board staff during the teleconference following the interrogatory responses for more information as to how the timing of these expenditures would impact the amounts that were spent in the 2014 Test year.[9] FFPC stated that the impact on the

[8] EB-2013-0130 *Fort Frances Power Corporation Response to Issues 1-3 Interrogatories May 22, 2014,* pp. 5-6 1.1-Staff-2.
[9] EB-2013-0130 *Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* pp.3-4 1.1-Staff-41.

total 2014 expenditures of the potential inability to connect one of the 14 customers by the end of 2014 would range from between $30,000 to $46,446.

Board staff also requested that FFPC elaborate on the impacts of the possibility which it stated it was open to doing of implementing the LTLT project in three annual phases. FFPC stated that this would reduce the 2014 planned capital expenditures for this project from $371,737 to $270,767 with a corresponding OM&A reduction of $5,048.

Board staff has a number of observations on FFPC's LTLT proposal and concerns with it.

First, Board staff notes that LTLT's normally arise when a customer is located in the licensed service area of one electricity distributor (the "geographic distributor") but is physically connected to another electricity distributor's distribution system (the "physical distributor"). Under a typical LTLT arrangement, while the customer is connected to the physical distributor's distribution system, the LTLT customer is billed by the geographic distributor and pays the geographic distributor's electricity distribution rates.

This leads to Board staff's first observation which is that based on the description of the arrangements for these 14 customers as described by FFPC, this is not a typical LTLT arrangement because in this case these 14 customers are not billed by the geographic distributor (FFPC), nor do they pay FFPC's distribution rates.

FFPC references Section 6.5.4 of the DSC which states as follows:

> 6.5.4 During the period between May 1, 2002 and June 30, 2014, a geographic distributor that services a load transfer customer 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.
>
> Once a load transfer customer enters into a Connection Agreement or implied contract with the physical distributor, the physical distributor shall have sole responsibility for that customer.

A geographic distributor, with respect to a load transfer is defined in the DSC as meaning the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer, while the physical distributor, with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly.[10]

Board staff submits that contrary to the DSC in this case Hydro One, the physical distributor, is also responsible for directly connecting and billing these customers that are not in the service area.

Board staff asked FFPC why it did not install its own meters.[11] FFPC responded that:

> The electrical distribution system within the Town of Fort Frances and its proximity to customers are a product of history. At the time that the LTLT homes were electrified, FFPC's electrical distribution system was not in close proximity to most of the homes and the 1905 Historic Power Agreement dispute had not been resolved. The LTLT customers were simply connected to the distribution network that was in closest proximity to them. The Power Agreement dispute was formally resolved in 1983 with the ruling of the Supreme Court of Canada.
>
> Although FFPC believes that the LTLT customers are eligible to receive the benefits of the Agreement, FFPC does not believe that it has ever had the consent from stakeholders including Hydro One and the Board, to proceed with replacing the metering assets of Hydro One with those of FFPC.
>
> Therefore, FFPC did not install its smart meters on the LTLT customer premises as part of its smart meter roll-out as it did not believe that it had the authority to do so.

Accordingly, Board staff submits that the situation described by FFPC is not a load transfer situation as defined by the DSC and, as such, the DSC does not require FFPC to proceed in the manner which it has proposed. Board staff is of the view that these 14 customers have been treated as Hydro One customers despite being located in FFPC's area and this situation has been ongoing for many years.

FFPC's explanation above does not address why it was not possible through the years for FFPC to have installed its own meters for these customers so that the customers could have been billed directly by FFPC and have been paying FFPC rates.

Whether this situation is in non-compliance with the licence conditions for both utilities would normally not be determined in a cost of service application, though the Board

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[10] Ontario Energy Board *Distribution System Code Last Revised on August 26, 2013 (Originally Issued on July 14, 2000),* p. 13 and p. 16.

[11] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* p. 3 1.1.-Staff-40 c.

could initiate a proceeding on its own motion to consider this issue. Given this is a cost of service application, this submission focusses only on the prudence of the expenditures proposed by FFPC for this project in terms of setting just and reasonable rates.

At question is whether it is reasonable for FFPC to spend an average of over $26,000 per customer to connect these customers, or whether the more appropriate remedy is for FFPC to request a service area amendment which would formally transfer these customers to Hydro One.

Board staff notes that the Board is currently undertaking a policy review of LTLT situations. The results of this review should be available in the coming months. It may be prudent at this time wait for the outcome of this review.

Board staff is however mindful of the other benefits of this project cited by FFPC and submits that it would be reasonable for FFPC to develop the capacity to be able to provide service to this portion of its territory. However, the evidence supporting likely additional growth of load or the need to connect renewable generators in this service area was very weak.

It is Board staff's submission that a more phased development plan for the servicing of this territory (excluding the connection of the subject customers) would be appropriate. Further, when FFPC has a specific renewable generation facility, or other development proposal for this territory, it could bring such a proposal to the Board either at its next cost-of-service application or, if sooner, through the use of the Board's incremental capital module, if the proposed project meets the requirements outlined in Chapter 3 of the Board's *Filing Requirements for Electricity Distribution Rate Applications*.

b) System Renewal

Board staff submits that key tools are needed to be in place before FFPC is able to move investments in System Renewal, for all asset groups, from a Maintenance Mode to a Capital Rebuild Mode. Outlined below is Board staff's assessment of the tools that FFPC has in place and others that are in progress.

i) In-Place Tools

Board staff notes that FFPC established an asset registry for all its distribution system assets and general plant assets, which started with investment in a Geographic Information System (GIS) in 2005[12]. The GIS allowed gathering relevant field information on all its distribution system assets and general plant assets, and combining it with office records leading to a registry system for each asset in the various asset groups.

Board staff also notes that FFPC's asset registry was instrumental in 2008, for FFPC's[13] development of 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".

ii) In-Progress Tools

FFPC's response to an interrogatory[14] indicated that by end of 2016 it would be able to link health indexes to various asset classes (asset groups), and that risk ratings and consequences of failure attributes are projected to be linked by the end of 2017.

FFPC's response to the same interrogatory[15], indicated that once the two key tools noted above are in place, it is anticipating that it will be able to apply a process to determine the probability of failure for each individual major asset. FFPC stated in part that:

> FFPC has not fully investigated how to apply this approach. Conceptually, FFPC is planning to investigate developing probability of failure scores for individual assets based on failure rate as a function of:
>
> - age
> - operating environment/conditions
> - inspection/condition test results

[12] Directive dated Dec 16, 2013 to the OPA titled: Moving Forward with Large Renewable Energy Projects, Renewable Energy Projects in Remote First Nation Communities and Energy Storage p. 90, Section 5.3.1.2
[13] Ibid, p. 91.
[14] EB-2013-0130 *Fort Frances Power Corporation Response to Issues 1-3 Interrogatories May 22, 2014,* pp. 1-2 1.1-Staff-1.
[15] Ibid, p. 2

iii) Review of FFPC's Proposed Approach for Asset Replacement

FFPC is proposing to spend[16] a total of $2,068,500 on System Renewal over the 2014 to 2018 planning horizon. The primary basis for asset replacement is the FFPC Adopted Useful Life ("UL") for all its asset groups. FFPC justifies this approach as reasonable since it matches the Typical Useful Life ("TUL") values established in the Kinectrics Report[17].

Board staff agrees with FFPC that asset replacement is not determined by age alone, but also by assessment of the asset condition[18]. FFPC explained[19] that it performs further analyses to determine how available asset condition data affects the longevity of individual assets, including inspection results, condition testing results, asset performance data, employee expertise, root cause failure data from outage reports and known manufacturer defect information.

FFPC further indicated that utilizing these inputs, it adjusts the TUL expectancy of individual assets based on assessing the health of individual assets with favourable condition data extending the life expectancy of assets and unfavourable data decreasing it, 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 generates a listing that reflects FFPC's best guess as to the order in which assets will fail. FFPC concludes[20] by stating that:

> 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.

While Board staff acknowledges that FFPC is putting in place systems and processes that will support a strong asset management approach, Board staff submits that FFPC

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[16] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 2013,* E2.Appendix2A/p.256.
[17] July 8, 2010 *Kinectrics Asset Depreciation Study for the Ontario Energy Board* ("Kinectrics Report")
[18] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 2013,* E2.Appendix2A/p.98.
[19] Ibid
[20] Ibid

should postpone the proposed replacement of all its asset groups from Maintenance Mode to Capital Rebuild Mode until it has in place all the tools considered a pre-requisite, as outlined above.

As discussed above, FFPC has stated that by the end of 2016,[21] it would be able to link health indexes to various asset classes (asset groups), and that risk ratings and consequences of failure attributes are projected to be linked by end of 2017.

Board staff accordingly submits that FFPC's proposed Asset Renewal for some asset groups should be delayed until its next DSP (2019-2023), as outlined in the subsequent section.

iv) Recommended System Renewal Investments by Asset Group

Board staff's submission on FFPC's proposed investments for System Renewal is set out based on two asset groups: (1) Overhead & Pad-Mounted Transformers; and (2) Primary UG Cable Replacement and Rejuvenation.

Board staff has no submissions on FFPC's proposed expenditures in the other asset groups under System Renewal and accepts FFPC's proposals in these areas as filed.

- Overhead & Pad-Mounted Transformers

Board staff submits that while FFPC's Adopted UL[22] for the three transformer types [Overhead & Pad-Mounted Transformers (1-Phase and 3-Phase)] is 40 years, industry experience indicates that transformers can often surpass this age, especially those that are lightly loaded and that experience relatively few downstream faults. Frequent inspections of the system also identify transformers that have external damage (damaged insulators, oil leaks, or surface rust). Corrective actions can then be taken to either repair or replace any defective assets as appropriate.

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[21] EB-2013-0130 *Fort Frances Power Corporation Response to Issues 1-3 Interrogatories May 22, 2014,* pp. 1-2 1.1-Staff-1.
[22] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 2013,* E1/T1/S8, pp. 3-4, Table 1.8

Board staff notes that FFPC's evidence shows that no transformers have needed replacement going back at least as far as 2006.[23] In spite of this, FFPC is proposing a cumulative total expenditure of over $1,000,000 in the 2014 to 2018 period for transformer replacement. By contrast, the investments in fully dressed wood poles which FFPC is proposing for the 2014 to 2018 period average $129,928 per year as compared with the historical investment levels in the 2011 to 2013 period averaging approximately $140,000.

FFPC's response to an interrogatory[24] provided information on each transformer proposed for replacement in the years 2014 to 2016. Board staff has summarized below the information provided in this interrogatory response in tabular form:

Year	**Total Number of Transformers**	**Impact of Failure & Number of Transformers under each category**						
		Very High	**High**	**Medium**	**Low**	**Very Low**	**Asset Failed**	**Not suitable for reuse**
2014	15	1	3	3	5	0	3	0
2015	36	4	4	12	7	1	4	4
2016	20	2	7	2	6	0	0	3

Board staff submits that in order to pace the investments FFPC should only replace transformers that have customer impacts categorized by FFPC as "Very High" or "High" in addition to those reported as "Failed" or "Not suitable for reuse". Board staff therefore submits that for the 2014 Test year, funding should only be provided for only 7 out of the 15 transformers proposed to be replaced. Board staff further submits that FFPC should continue to follow such an approach for the remainder of the DSP period, or until FFPC is able to link health indexes to various asset classes (asset groups), and also is able to link risk ratings and consequences of failure attributes to these assets.

Board staff submits that, based on the above, it would be appropriate that the $95,648 requested for capital projects by FFPC in this category in 2014 be reduced to $50,000.

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[23] Ibid, Exh 2/T3/Sch 1/ p.4

[24] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014, pp. 6-7* 1.1-Staff- 45.

- Primary UG Cable Replacement and Rejuvenation

Board staff notes that FFPC is proposing expenditures in this category totalling $180,537 in the 2014 to 2018 period with $16,251 being proposed for expenditure in 2014. Board staff accepts FFPC's proposed expenditures in this category.

Board staff was initially concerned about FFPC's plans to consider cable rejuvenation through silicone injection as discussed in a Board staff interrogatory in which FFPC was asked to discuss other alternatives which it might consider if it was not to make use of the cable injection option[25].

Board staff is in agreement with the approach outlined by FFPC in its response to this interrogatory for dealing with this matter.

v) Feasibility of FFPC's Proposed DSP

As noted under issue 1.1. Board staff considers that the longer-range perspective of FFPC's DSP is in line with the approach the Board intended with its creation of the requirement to file a DSP.

However, Board staff submits that FFPC may be proceeding too aggressively in implementing its plans as its asset management planning may be improved by allowing more time to build up expertise and experience in the asset management planning process, which is the basis for some of the proposed reductions in FFPC's proposed 2014 capital program recommended by Board staff.

Board staff notes that the average level of FFPC's capital spending in the 2006 to 2012 period was around $269,000. By contrast, the average for the period of the five-year DSP is around $700,000, which is almost three times higher.

In the normal course, Board staff would be concerned with a distributor ramping up its capital program to align with its rate setting cycle. In this instance however, FFPC has not rebased since 2006 and while it can be argued that this scheduling was by choice (as FFPC has requested four deferrals since 2010), the fact remains that an increased

[25] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 4 Interrogatories May 22, 2014, p*p. 9-10 4.1-Staff-12.

capital budget to address system needs after eight years of minimal rate adjustments is understandable.

That said, Board staff submits that this approach is too aggressive overall and FFPC should have a more phased approach to increasing its level of capital expenditures. In addition, Board staff observes that FFPC's service reliability indicators have been improving over the past three years and there does not appear to be sufficient evidence to support a 100% conversion to a Rebuild Mode.

Board staff is proposing two reductions in FFPC's 2014 capital program. The first is the elimination of the proposed LTLT expenditure of $371,739 and the second is the reduction in the expenditures on overhead and pad mounted transformers from the proposed level of $95,648 to $50,000. The impact of these two reductions would be to reduce FFPC's 2014 capital expenditures from $820,316 to $402,929, a reduction of approximately 50%. Board staff submits that this level of expenditures is a more reasonable one for FFPC to undertake given its experience with historical expenditure levels.

Board staff submits that FFPC's DSP was presented on a stand-alone basis, and followed the structure as outlined in the Board's Chapter 5 Filing Requirements. Board staff is of the view that while the plan is relatively comprehensive, FFPC's next DSP would benefit from:

- More emphasis on specific customer feedback regarding the DSP, which did not include any surveys focused on conveying certain key initiatives and getting feedback from the customer on them e.g., in regard to investments in System Renewal and the impact on rates of moving from a Maintenance Mode to a Capital Rebuild Mode. Board staff considers the extent of customer engagement underlying the present DSP as appropriate given that 2014 is a transitional year for the outcomes approach;

- FFPC should attempt to monetize the savings to be achieved in its OM&A over the 5-year planning period for each asset group, as it moves from a Maintenance Mode to a proactive Capital Rebuild Mode; and

- FFPC should not fully transition from its present Maintenance Mode to its planned Rebuild Mode, until all the tools needed for such implementation are developed and operational to avoid replacing assets prematurely.

Service Reliability & Quality Indicators

Background

FFPC provided reliability statistics for 2008-2012, which showed a generally improving or stable trend in the latter three years.

FFPC's service quality statistics, as reported in the application show that the Board's service quality requirements are being met or exceeded:

Discussion and Submission

Board staff accepts FFPC's evidence on these topics and has nothing further to add.

4.2 Are the applicant's proposed OM&A expenses clearly driven by appropriate objectives, and do they show continuous improvement in cost performance?

Operations, Maintenance and Administration ("OM&A")

Background

FFPC is proposing 2014 OM&A expenses of $1,657,650 excluding taxes and amortization expenses. This represents a 3.3% increase over the 2012 actuals and a 65% increase over the 2006 Board Approved level. The following table summarizes the changes in OM&A that have occurred since FFPC's last cost of service application in 2006.

	2006 Approved	2006 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Operation	$142,165	$154,931	$192,399	$195,697	$213,851	$209,500	$371,000
Maintenance	$106,651	$92,874	$183,394	$169,076	$377,219	$213,000	$304,000
Billing and Collecting	$144,547	$237,343	$265,204	$213,984	$255,946	$235,500	$268,000
Community Relations	$4,712	$62,599	$8,805	$6,024	$5,978	$4,750	$37,150
Administrative and General	$603,271	$577,417	$675,883	$717,211	$751,977	$763,500	$677,500
Total OM&A	$1,001,346	$1,125,164	$1,325,685	$1,301,992	$1,604,971	$1,426,250	$1,657,650
Year to year % change				*-1.8%*	*23.3%*	*-11.1%*	*16.2%*
% change as compared to 2006 Approved		*12.4%*	*32.4%*	*30.0%*	*60.3%*	*42.4%*	*65.5%*

FFPC has budgeted approximately $95,131[26] for the costs of the Application (including consulting, legal and intervenor costs). FFPC proposes to recover these costs over 5 years.

Discussion and Submission

Board staff notes that a number of the variances in line items are due to reclassifications/reallocations between the various categories for the reasons described in the application. The key drivers for the 2014 over 2013 increase in OM&A are the following:

- $60,739 for the hiring of one FTE in June 2014;
- $42,000 for distribution lines and feeders related to incremental OM&A expenses to complete FFPC's Long-Term Load Transfer capital project and salary and benefits for the work performed by the Customer Service Technician to update and maintain FFPC system maps and records;

[26] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 4 Interrogatories May 22, 2014,* p.40, 4.2-VECC-12.

- $32,500 for billing and collecting related to higher contracted costs for contracted services, materials and postage paid to the Town of Fort Frances and Thunder Bay Hydro and additional wages for customer service technician collection activities;

- $25,400 for energy conservation and community relations for salary/benefits and training for the customer service technician.

Board staff notes that a considerable amount of the 2014 cost increase is related to the anticipated hiring of one new FTE in 2014. In response to an interrogatory from Board staff related to this matter,[27] FFPC observed that it has not increased staff within the last rate period (2006 to 2014) except to hire apprentice linemen in advance of retirement vacancies. FFPC also noted that staffing changes in small LDCs create large percentage changes. Board staff agrees with FFPC and submits that FFPC's proposed cost level for the Test year is reasonable.

Board staff submits that FFPC's proposed OM&A expenses are driven by appropriate objectives, specifically improvement of service to customers and increased customer engagement through the hiring of one FTE whose position is described as a Technical Customer Service Representative. The proposed OM&A expenses would also provide an appropriate foundation to allow FFPC to show appropriate continuous improvement in cost performance given FFPC's circumstances.

The only adjustment which Board staff believes would be necessary would be the disallowance of the $25,681 proposed expenses related to the LTLT capital project to reflect Board staff's submissions in this area. While this amount is below the FFPC materiality threshold, given that it is intended to support a project that may not proceed, the expense should not be approved if the Board adopts Board staff's submission on this project.

In making its OM&A submissions, Board staff is mindful of its submissions in section 2.1 which noted that most of the costs which FFPC considered unique in expressing its belief that its current reported OM&A cost data are flawed do not appear to be unique. Board staff, accordingly, considers FFPC to be a high-cost performer and would normally under

[27] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 4 Interrogatories May 22, 2014,* p.29 4.2-Staff-17.

such circumstances submit that a further reduction in the OM&A request should be made. However, FFPC's rate minimization strategy, as characterized by the zero return on equity request, has resulted in long term savings for ratepayers .Board staff does not believe that any further OM&A reductions are necessary.

Board staff submits that it would be prudent for FFPC to better control its OM&A cost increases going forward, especially in light of the increased revenue stream that it will realize following this application for new rebased rates.

4.3 Are the applicant's proposed operating and capital expenditures appropriately paced and prioritized to result in reasonable rate for customers, or is any additional rate mitigation required?

Background

FFPC's evidence demonstrated that Bill Impacts on the Total Typical Customer Bill for all customer classes are below 10%.

Discussion and Submission

Board staff submits that because FFPC's proposed rate increases for all customer classes are below 10%, no additional rate mitigation is required.

Distribution System Plan Overall Conclusion

Board staff submits that the DSP filed by FFPC combined with the resources made available to it as proposed in the updated application, as modified if Board staff's submissions are accepted by the Board, would provide an appropriate foundation for FFPC in the Test year to: a) pursue continuous improvement in productivity; b) attain appropriate system reliability and service quality objectives; c) maintain reliable and safe operation of its distribution system; and d) produce reasonably based bill impacts.

5. Public Policy Responsiveness

5.1 Do the applicant's proposals meet the obligations mandated by government in areas such as renewable energy and smart meters and any other government mandated obligations?

Background

FFPC currently does not have any planned investments specific only to achieving smart grid objectives. However FFPC is proposing $50,000 in 2014 investments related to its development of a renewable enabling improvement plan. This is aimed at safely and reliably accommodating the connection of renewable energy generation facilities through improvement to its transformer station “FFMTS,” which presently cannot accommodate 2-way or reverse electrical flow at any level. FFPC is also proposing recovery of $53,757 for all renewable energy generation (“REG”) costs that FFPC incurred up to the end of the 2013 calendar year, including capital, OM&A and carrying charges booked in the Board established deferral accounts.

Discussion and Submission

While Board staff has some concerns about the extent to which FFPC’s proposed renewable enabling improvement expenditures may also be considered as normal distribution system expenditures and believes that FFPC should provide a stronger rationalization in future applications as to how it distinguishes expenditures included in its REG plan from normal expenditures, Board staff accepts FFPC’s proposed REG plan as reasonable along with the proposed allocation percentages.

Subject to the above considerations, Board staff submits that FFPC’s proposals meet the obligations mandated by government in areas such as renewable energy and smart meters and any other government mandated obligations.

6. Financial Performance

6.1 Do the applicant’s proposed rates allow it to meet its obligations to its customers while maintaining its financial viability?

Background

FFPC stated that since it operates under a 0% rate-of-return, it does not have a profit margin buffer of up to 9.8% per year to absorb unforeseen expenses or the financial impact of not achieving expected efficiency gains. FFPC’s 2012 financial statements showed a deficit of $513,338 at year end.[28] However, FFPC expressed the belief that the revenue requirement requested in the Application would be sufficient to avoid the development of another accumulated deficit over the 2014 to 2018 rate horizon.[29]

FFPC confirmed that it maintains a current cash investment level of $2.1 million for future capital expenditures, as a matter of policy at the direction of its Board of Directors. FFPC justifies this policy by noting that its transformer station is comprised of a relatively low number of highly priced core components such as power transformers and that the failure of a single power transformer would result in a capital replacement cost of approximately $914,900. FFPC also noted that its intensified capital replacement program is expected to significantly reduce the current cash investment level.[30]

FFPC was asked in a Board staff interrogatory[31] to state whether the rate relief requested in the Application is expected to be sufficient to allow it to avoid the development of another accumulated deficit in the period before FFPC's next cost-of-service application and, if not what actions FFPC would anticipate taking to deal with this matter. FFPC responded that it expects the rate relief requested in its Application would be sufficient to avoid the development of another accumulated deficit.

FFPC, however, noted that the May 2014 closing of the Resolute Paper Mill, which is a direct industrial Hydro One customer, could impact this expectation due to the loss of billable consumption associated with FFPC's Resolute General Service customers and due to possible related business closures and housing vacancies. FFPC stated that as it did not supply the manufacturing portion of the mill, its load forecast is still expected to be reasonable, as it was built with the anticipation of a reduction in load due to curtailment of production at the mill. FFPC concluded that it expected to see slight year-over-year reductions in electricity consumption as residents migrate or struggling businesses close,

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[28] EB-2013-0130 *Fort Frances Power Corporation Application Financial Statements for the year ended December 31, 2012.*

[29] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* p.22 6.1-Staff-45.

[30] EB-2013-0130 *Fort Frances Power Corporation Response to board Staff Teleconference on may 29, 2014 Filed on June 11, 2014,* p. 21 6.1-Staff-44.

[31] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 6 Interrogatories May 22, 2014,* pp. 2-3 6.1-Staff-23.

in the event no new economic development occurs, rather than drastic short term effects.[32]

FFPC stated that in the event the rate relief requested in the Application is insufficient to avoid the development of another accumulated deficit, it might seek approval for a "deficit recovery rate-rider" as part of its annual IRM rate setting process following the year in which the deficit was recorded. FFPC stated that the rate rider could be specifically designed to recover prudently incurred expenses, or reductions in revenue, which would cause FFPC to have an actual annual deficit that would have been absorbed if it operated under a rate-of-return model.

Discussion and Submission

Board staff notes that FFPC's "deficit recovery rate-rider" proposal does not appear to be in line with the Board's current rate-setting policies. Specifically, in the event that FFPC was to develop another accumulated deficit, it might prove necessary for FFPC to file another cost-of-service application earlier than would normally be the case which would represent a considerable expense for FFPC.

As such, Board staff submits it is desirable that any rate relief received by FFPC as a result of this Application be sufficient to allow it to avoid developing another accumulated deficit similar to the one that has precipitated the present application during the normal 5-year period between cost of service applications.

In this context, Board staff notes that, as has already been discussed, FFPC is anticipating completing a much larger annual capital program beginning in 2014 than has been the case in previous years in an environment of declining revenue as reflected in the Resolute Forest Products closing, while seeking an ROE of 0%.

In assessing the options available to the Board and FFPC for dealing with this situation, Board staff notes that FFPC does not state that it is a not-for-profit corporation as defined by Bill 210, the *Electricity Pricing, Conservation and Supply Act*, 2002. Accordingly, it is Board staff's understanding that FFPC is a 'for-profit' corporation, that has chosen to earn a zero percent return. Board staff invites FFPC to clarify or correct this understanding in its reply submission if necessary.

[32] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* p. 22 6.1-Staff-45.

Board staff further notes that during the course of the proceeding, there have been some discussions of the applicability of the Board's reserve fund approach to FFPC's circumstances given its zero percent return. It is Board staff's view that since FFPC is a "for-profit' corporation it would not be eligible for this approach. In any event, FFPC stated in response to a Board staff Teleconference question[33] relating to the reserve fund approach that to accurately evaluate this approach would be a very extensive and involved process and as such FFPC did not believe that it would be able to consider this alternative as part of the Application.

Board staff also notes that in response to a Board staff interrogatory which asked FFPC to provide the provisions of the Agreement and the 1983 Supreme Court ruling [34] on the Agreement which FFPC believes require it to choose a zero rate of return to preserve the Agreement benefits, FFPC stated that it did not believe any provision of the Agreement, or the Supreme Court ruling required it to choose a zero rate of return.[35] FFPC stated that the reason it had chosen the zero rate of return was to be consistent with its rate minimization strategy and to minimize the likelihood of a successful attack on the Agreement.

Board staff submits that there are a number of risks facing FFPC during the next five years that may impact on whether or not the proposed rates would allow it to meet its obligations to its customers while maintaining its financial viability including some that are unique to FFPC.

Board staff submits that one option open to the Board to mitigate these risks would be for it to determine that FFPC should have its rates set by applying the Board's deemed cost of equity. Board staff is mindful of the concerns that FFPC would have with such an approach and also the impact that it would have on FFPC's customer rates at a time of economic challenges for the Fort Frances community. Accordingly, on this basis, Board staff accepts FFPC's rate minimization strategy and believes that the most realistic

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[33] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* p.23 7.5-Staff-46.

[34] *Supreme Court of Canada Decision ([1983] 1 SCR 171)*

[35] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 7 Interrogatories May 22, 2014,* pp. 7-10 7.5-Staff-27.

approach for mitigating FFPC's risks given all of these factors would be the recommended changes to FFPC's Distribution System Plan, suggested by Board staff in section 4.1 of this submission.

Board staff also recognizes that outside of rate applications, the Board has processes to monitor the financial viability of electricity distributors. The licence of FFPC includes section 14.2 that requires notification to the Board of any material change in circumstances. Board staff is of the view that this licence provision would require FFPC to notify the Board of any circumstances that may affect the Agreement.

6.2 Has the applicant adequately demonstrated that the savings resulting from its operational effectiveness initiatives are sustainable?

Background

FFPC's operational effectiveness initiatives have been discussed in section 4 of this submission.

Discussion and Submission

Board staff notes that 2014 is a transition year and as such quantitative evidence of FFPC's past operational effectiveness initiatives is not readily available. Board staff submits that FFPC has demonstrated that it is pursuing operational effectiveness initiatives as set out in the Application. Board staff further submits that it would be appropriate for FFPC to address the savings resulting from these and other operational effectiveness initiatives and the sustainability of savings from these initiatives with evidence in its next cost-of-service application.

7. Revenue Requirement

7.1 Is the proposed Test year rate base including the working capital allowance reasonable?

Rate Base

Background

FFPC is requesting approval of $4,793,453 for the 2014 rate base. This amount represents a 7.5% increase from its approved 2006 rate base. Changes in rate base from 2010 to 2014 are shown in following table:

	2006 Approved	**2010 Actual**	**2011 Actual**	**2012 Actual**	**2013 Bridge**	**2014 Test**
Rate Base	$4,460,594	$4,050,961	$4,097,757	$4,395,821	$4,402,553	$4,793,453
% change as compared to prior column		-9.2%	+1.2%	7.3%	0.1%	8.9%

FFPC stated that the increase in 2014 arose from higher net fixed assets, primarily due to planned feeder expansions to eliminate LTLT, new line transformers and transportation equipment for the replacement of a cable reel & tensioning trailer. The increases in 2012 are largely due to incorporation of smart metering asset additions in rate base.[36]

Discussion and Submission

Board staff has already provided its submission on many of the issues related to rate base above in the capital expenditures section under Issue 4.3. Board staff's submissions on the remaining rate base issue follows.

Working Capital Allowance

Background

FFPC calculated its Working Capital Allowance ("WCA") using the default 13% allowance approach as per the Filing Requirements. The WCA is $1.1million in the 2014 Test year, which is an increase of $36,000 or 4% over the 2013 forecasted WCA and a 19% decrease over the 2012 actual.

[36] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 2013,* Exh 2/T1/S2/p.18 and p.24

Discussion and Submission

Board staff takes no issue with FFPC's proposal.

7.2 Are the proposed levels of depreciation/amortization expense appropriately reflective of the useful lives of the assets and the Board`s accounting policies?

Depreciation

Background

FFPC has filed under Canadian Generally Accepted Accounting Principles (" CGAAP") for 2014, but has adjusted depreciation in 2012 to a Modified International Financial Reporting Standards("MIFRS") calculation which produces depreciation of $216,119, a reduction of $194,245 from the 2012 CGAAP depreciation calculation of $564,032. This is also reduced by $153,666 due to an adjustment in smart meter amortization.

FFPC, through its contracted services to the Town of Fort Frances, stated that it had calculated depreciation on the whole year and did not use the Board policy of the "half-year" rule. FFPC stated that it realizes its approach of using a full year of depreciation deviates from standard practice and will implement the half year rule methodology in 2014. FFPC expressed its understanding that its current rates were approved in 2006 which assumed full year depreciation on new capital at the time. FFPC stated that 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 $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.

Discussion and Submission

Board staff accepts that FFPC has not used the half-year rule for the historical period based on the low materiality of this departure and that FFPC will use the half-year rule on a going-forward basis. On this basis, Board staff accepts FFPC's proposed depreciation expense. Board staff notes that FFPC has documented its depreciation rates in its Application[37] and stated that it has adopted Kinectrics' proposed useful lives and

[37] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 2013,* Exh 4/ Tab 3/S 1/p.2

componentization but adjusted, when necessary, to reflect FFPC's Asset Management Policy.

7.3 Are the proposed levels of taxes appropriate?

Background

FFPC is not expecting to pay income taxes in 2014 as it is forecasting negative income for tax purposes in 2014.

Discussion and Submission

Board staff accepts that the proposed level of payment in lieu of taxes for this Application is $0.

7.4 Is the proposed allocation of shared services and corporate costs appropriate?

Shared Services and Corporate Costs

Background

FFPC stated that it performs and receives services from its shareholder, the Municipality of the Town of Fort Frances. FFPC performs rework and street light maintenance meter reading at the same rates as is charged to other customers. 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 stated that its 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. FFPC further stated that it 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.

FFPC's shareholder also provides FFPC with contracted services for meter reading, billing, collecting and accounting services required by FFPC to serve its customers. FFPC stated that 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 stated that its 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. FFPC noted that this shared location is convenient for residents, FFPC customers and all staff.

FFPC provided in Appendix 2-N Shared Services and Corporate Cost Allocation detailed explanations of the pricing methodologies for the services provided to it by the Town of Fort Frances.

Discussion and Submission

Board staff notes that FFPC's explanations of its pricing methodology for shared services are cursory, focusing more on what the pricing is, rather than the methodology employed. However, based on FFPC's statement in Appendix 2-N that it is in full compliance with the Affiliate Relationships Code, as per FFPC's RRR Filing 2.2 Certificate for 2012, Board staff accepts FFPC's evidence in this area. However, Board staff is not commenting at this time on whether the provision of street lighting services is compliant with Section 71 of the OEB Act, as consideration of this issue would generally be considered out of scope of a cost of service rate application.

7.5 Are the proposed capital structure, rate of return on equity and short and long term debt costs appropriate?

Cost of Capital

Background

FFPC's cost of capital proposals are summarized in the table below:

FFPC 2014 Cost of Capital Proposals		
	Board Parameters	FFPC Proposal
	25-Nov-13	
Capital Costs		
Return on Common Equity	9.36%	0
Long-Term Debt Rate	4.88%	4.88%
Short-term Debt Rate	2.11%	2.11%
Capital Structure		
Common Equity	40%	40%
Long-term Debt	56%	56%
Short-term Debt	4%	4%
Weighted Average Cost of Capital	6.56%	2.82%

FFPC is proposing that the Board's cost of capital parameters, as updated in its November 25, 2013 letter be used with the exception that it is making a request for a zero return on common equity.

FFPC stated that it is making this request to preserve the benefits of the Agreement which results in reduced power costs for its customers. As has been discussed previously, FFPC stated that it has elected to operate within a 'not-for-profit' structure in part to ensure the safeguarding of the Agreement on behalf of its customer base within the Town of Fort Frances. The Board's 2006 cost of service decision approved a 0% ROE.

FFPC stated that the basis of its request to be allowed to recover the Board's deemed debt cost, even though it has no outstanding debt, is the Board's Cost of Capital Report of December 2009, which states that where a utility has no actual debt, the deemed long-term debt rate shall apply.

FFPC further stated that it believed that its circumstances would be similar to other LDCs which operate at less than 60% debt. FFPC stated that its challenge is that as it operates under a 0% rate of return, it does not have a profit margin buffer of up to 9.8% per year from which to absorb unforeseen expenses and not achieving expected efficiency gains.

FFPC expressed the belief that in light of this, the deemed debt cost is a good fit for it as it provides for a modest buffer and funds to FFPC similar to other LDCs that operate at less than 60% debt.[38]

Discussion and Submission

Board staff notes the unique aspects of FFPC's cost of capital proposals discussed above. FFPC is requesting a 0% rate of return on common equity even though it has outstanding common equity and a recovery of the Board's deemed debt rates even though it has no outstanding long-term debt. While Board staff is concerned about these inconsistencies and does not endorse them, Board staff submits that the weighted average cost of capital of 2.82% proposed by FFPC is much lower than the 6.56% that would result from an application of all of the Board's cost of capital parameters resulting in considerable savings to FFPC's customers. Board staff submits that given FFPC's unique circumstances, including cash reserves presently exceeding $2 million, this would be a sufficient buffer for FFPC in the years ahead. Board staff notes that its position would also be consistent with the Board's endorsement in 2006 of FFPC's rate minimization strategy[39]. As noted previously, the Board does maintain an ongoing process of monitoring financial viability of distributors.

7.6 Is the proposed forecast of other revenues including those from specific service charges appropriate?

Other Revenues

Background

FFPC's projected Other Operating Revenue in the 2014 Test year is $108,033 $11,299 less than in the 2013 Bridge year, or a 9.5% drop, and $5,863 less than the 2012 Actual, or a 5.1% drop.[40]

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[38] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* pp. 23-24 7.5-Staff-46.
[39] RP-2005-0020 EB-2005-0366 April 12, 2006 Fort Frances Power Corporation *Decision and Order,* pp. 3-4.
[40] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on April 4, 2014 Filed on April 17, 2014,* p.16, Question VECC#1.

Discussion and Submission

Board staff notes that the changes in these amounts are well below FFPC's materiality threshold and FFPC has provided a detailed explanation for them. Board staff accepts FFPC's evidence on this matter.

Specific Service Charges

Background

FFPC is proposing the removal of unused charges and a revision of some existing charges to recover current business costs.

FFPC noted that its specific service charges have been unchanged since deregulation.

FFPC requested the removal of eight specific service charges, as listed below. FFPC stated that these charges were seldom used and not specific enough to recover costs from various types of temporary service installation. FFPC further stated that it had recovered these costs in the past through recoverable work charges and by directly billing 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 also requested increases in six specific service charges resulting in a total 2014 Test year forecast revenue increase of $849. The proposed increases are listed below:

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

Discussion and Submission

Board staff submits that the eight charges for which FFPC is requesting removal are ‘standard’ charges in that they normally appear on distributor tariffs. However, on the basis of FFPC’s statement that these charges were seldom used, Board staff accepts FFPC’s position that they should be deleted from the Tariff.

Board staff notes that FFPC provided calculations in support of its proposal to increase the referenced six charges as outlined in Chapter 2 of the Board’s Filing Requirements. Board staff accordingly accepts FFPC’s proposal.

7.7 Has the proposed revenue requirement been accurately determined from the operating, depreciation and tax (PILs) expenses and return on capital, less other revenues?

Background

FFPC stated that its net revenue deficiency is $459,007 with no adjustment for PILs, as FFPC is not anticipating paying any 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.

FFPC noted that there are two main contributors to the revenue deficiency of $459,007 for the 2014 Test Year, which are:

(1) $72,723 due to inflation on base operating costs, and.

(2) $370,985 for payroll and benefit cost increases since 2006.

Discussion and Submission

Board staff accepts FFPC’s calculation of its revenue requirement, subject to any positions taken by Board staff in this submission that would lead to a modification of it. Board staff notes that its proposed reductions in FFPC’s capital spending on the LTLT project and the overhead & pad mounted transformers would result in approximately a $54,000 or 3% reduction in FFPC’s base revenue requirement.

8. Load Forecast, Cost Allocation and Rate Design

8.1 Is the proposed load forecast, including billing determinants an appropriate reflection of the energy and demand requirements of the applicant?

Customer Forecast

Background

FFPC developed its customer connection forecast based on a review of historical customer/connection data which is used to determine growth. A geometric mean approach was used to determine the 2013 and 2014 forecasts.

FFPC is seeking Board approval for a test year customer forecast of 4,754 customers/connections. The test year forecast is approximately 0.6% lower (or 29 customers/connections) than the 2012 actual. The following table summarizes the customers/connections forecast for 2014:

Customer Count Forecast 2014 Test Year Customer Count Forecast (Exhibit 3/ Tab 2/ Schedule 1/ Table 3.2.8)	
Rate Classes	**No. of Customers/Connections**
Residential	3,290
GS < 50 kW	405
GS 50 to 4,999 kW	47
Street Lighting	1,006
Unmetered Scattered Load	6
Total	4,754

Discussion and Submission

Board staff notes that FFPC's customer forecast shows a small decrease from the 2012 actual to the 2014 Test year. This is consistent with the gradual customer decline in recent years. Board staff accepts FFPC's 2014 customer forecast. Board staff assumes that the reason FFPC's load is forecast to increase while its customer numbers are forecast to decline is because the average level of customer consumption will increase. Board staff would suggest that FFPC could clarify this matter in its reply submission.

Load Forecast

Background

FFPC is seeking Board approval for a test year forecast of 78,161,019 kWh[41] or 78.61 GWh. The forecast represents a 1.5% increase from 2012 actual.

To develop its load forecast, FFPC used a multifactor regression model to determine the relationship between historical load with weather data and calendar related events. FFPC presented the comparison of the results of the model with actual system load for the period from 2003 to 2012.

The following were used as the inputs for the model to generate the weather-normalized system purchases for 2013 and 2014:

- Heating Degree Days
- Cooling Degree Days
- Number of Days in the Month
- Spring Fall Flag
- Number of Customers
- Ontario Real GDP Monthly
- 2012 Flag.

he allocation of the weather-normalized system purchases to each class is calculated by developing a customer connection forecast, based on reviewing historical customer/connection data. The growth rates in customer/connections are then evaluated and growth rates determined. The geometric mean approach provides the average compounding reduction rate from 2003 to 2012, which is then applied to determine forecast customer/connections for 2013 and 2014 by rate class. A similar process is used to determine usage per customer in the forecast. The non-normalized weather billed energy forecast is then determined by applying the forecast number of customers/connections by the forecast of annual usage per customer/connection.

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[41] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 2013,* Exh 3, Tab 2, Sch 1, p. 3.

This non-normalized weather billed energy forecast is then adjusted to be aligned with the total weather normalized billed energy forecast. The difference is assigned on a *pro rata* basis to each rate class based on its determined level of weather sensitivity.

FFPC made further adjustments to account for CDM totaling 1,148,562 kWh[42] to the 2014 test year forecast. This is determined as one half of the savings from 2012 programs, a full year of savings from 2013 programs and a half year of savings from 2014 programs. FFPC has apportioned 741,653 kWh of the total 2014 savings to the Street Light class to reflect 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' Sustainability Initiatives.

The class-specific forecasts are summarized in the following table:

2014 Test Year Load Forecast	
Rate Classes	**kWh**
Residential	37,751,518
GS < 50 kW	13,617,679
GS 50 to 4,999 kW	26,376,324
Street Lighting	366,947
Unmetered Scattered Load	48,552
Total	78,161,019

Discussion and Submission

Board staff notes FFPC is forecasting a 1.5% load growth from the 2012 Actual Year to the 2014 normalized test year. Board staff also notes that FFPC's actual load had been gradually decreasing from 2007 when it was 84,053,323 kWh to 2012 when it was 76,975,895 kWh. However, the load increased to 78,778,343 kWh in 2013, which suggests that the 2014 forecast is reasonable (a 0.8% decrease). Board staff accordingly accepts FFPC's load forecast as reasonable.

[42] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 2013,* Exh 3, Tab 2, Sch 1, p. 18.

Board staff also accepts FFPC's CDM forecast as reasonable and consistent with the Board's established approach on this topic. FFPC's class specific CDM adjustments are shown in the table below:

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.						

8.2 Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?

Cost Allocation

Background

FFPC stated that it has filed using the cost allocation model that reflects the findings in the *Report on the Review of Electricity Distribution Cost Allocation Policy, March 31, 2011.* ("Cost Allocation Policy Review") FFPC further stated that the data used in its updated cost allocation study is consistent with the cost data that supports the proposed 2014 revenue requirement outlined in the application and that its assets were broken out into primary and secondary distribution functions using the best current information available to FFPC.

FFPC provided an amended Table 7.8 which summarized the changes in the costs allocated to its customer classes from those in the previous 2006 study to those in the current study.[43]

[43] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on April 4, 2014 Filed on April 17, 2014,* p. 9 Board Staff #6.

Table 7.8: Proportion of Rate Specific Revenue to Total Revenue, 2006 vs. 2014 Cost Allocation

Classes	Costs Allocated from Previous Cost Allocation Study- 2006	% of 2006 Class Revenue to Total Revenue	Costs Allocated in 2014 Test Year Study	% of 2014 Class Revenue to Total Revenue
Residential	$ 930,775	62.03%	$ 1,366,130	68.66%
GS < 50 kW	$ 297,235	19.81%	$ 376,450	18.92%
GS > 50kW -4999	$ 241,620	16.10%	$ 218,356	10.97%
Street Lighting	$ 28,609	1.91%	$ 26,060	1.31%
Unmetered	$ 2,372	0.16%	$ 2,770	0.14%
Total	$ 1,500,611	100.00%	$ 1,989,766	100.00%

Discussion and Submission

Board staff accepts the changes in the cost allocations proposed by FFPC as reasonable given the adjustments proposed to the revenue-to-cost ratios to bring them in line with the Board's target ranges, as discussed in the following section.

Revenue-to-Cost Ratios

Background

FFPC is proposing adjustments to the resulting revenue to cost ratios to bring them into line with the Board's target ranges. FFPC is also proposing an adjustment to decrease the ratio for the General Service 50 to 999 kW class below the Board's maximum value of the target range in order to maintain revenue neutrality.

FFPC proposes to re-balance its class revenues as a result of its cost allocation results. The revenue-to-cost ratio of the GS 50 to 4,999kW class at 227.47% is well above the Board's policy range, while that for the Residential class is somewhat below.

The table below displays FFPC's 2006, current and proposed 2014 revenue-to-cost ratios and the Board's target ranges, as established in the Board's Cost Allocation Policy Review.

Revenue-to-Cost Ratios[44]

Customer Class	**2006 Board Approved %**	**Updated Cost Allocation Model %**	**Proposed 2014 %**	**Board Policy Range %**	**Total Bill Increase %**
Residential	91.60	83.44	97.50	85 – 115	4.85
GS < 50 kW	105.79	86.40	97.50	80 – 120	8.57
GS 50 to 4,999 kW	126.30	227.47	120.0	80 – 120	-8.62
Street Lighting	89.56	94.69	97.50	70 – 120	4.82
Unmetered Scattered Load	117.05	119.68	119.31	80 – 120	6.03

Discussion and Submission

Board staff notes that FFPC's proposed revenue-to-cost ratios are all within the Board policy ranges, generally in the middle of these ranges with the exception of the Street Lighting and Unmetered Scattered Load classes which are at the upper end of the Board's ranges.

Based on the submissions made by FFPC as set out above, Board staff accepts FFPC's proposed revenue-to-cost ratios.

8.3 Is the proposed rate design including the class-specific fixed and variable splits and any applicant-specific rate classes appropriate?

Monthly Service Charges ("MSC") and Fixed Variable Split

Background

FFPC is proposing to increase its monthly service charges as well as its volumetric charges for four of its five classes. The exception is the GS 50 to 4,999 kW class for which the fixed charge would decrease from $242.06 to $165.98 and the volumetric charge from $3.59 to $2.51.

[44] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on April 4, 2014 Filed on April 17, 2014,* p. 11 Board Staff #8.

The preferred reference point for MSC design is worksheet O-2 in the Cost Allocation model, in which customer-related costs are presented under alternative definitions of per-customer cost. The highest of these calculations is based on the Minimum System assumptions. This calculation is treated as an upper bound for the MSC, except for instances where the existing approved charge is already above the reference point.[45]

The table below shows the current and proposed fixed charges for each class, along with the ceiling values.

Monthly Service Charge

Rate Classes	Current	Proposed	Ceiling	Floor
Residential	$12.05	$18.79	$22.94	$9.18
GS < 50 kW	$29.03	$43.62	$33.19	$16.08
GS 50 to 4,999 kW	$242.06	$165.98	$72.00	$44.24
Street Lighting (per connection)	$1.17	$1.60	$8.93	$0.75
Unmetered Scattered Load (per customer)	$29.03	$38.24	$19.14	$7.00

FFPC is proposing to maintain the current fixed/variable split as follows:

Fixed/Variable Split

Rate Classes	Volumetric	Fixed	Total
Residential	41.12%	58.88%	100.00%
GS < 50 kW	38.91%	61.09%	100.00%
GS 50 to 4,999 kW	63.01%	36.99%	100.00%
Street Lighting (per connection)	18.56%	81.44%	100.00%
Unmetered Scattered Load (per customer)	13.29%	86.71%	100.00%

FFPC provided an explanation for the monthly fixed charges that exceed the ceiling as calculated in the cost allocation study.[46] FFPC noted that it has rate classes that fall within and beyond the maximum and minimum boundaries determined by the Cost

[45] Report of the Board, Application of Cost Allocation for Electricity Distributors (EB-2007-0667), page 12-13
[46] EB-2013-0130 *Fort Frances Power Corporation-2014 COS Application – Response to Letter of Incomplete February 11, 2014, p.9.*

Allocation Model. FFPC stated that the ideal for it would be to eventually align to an equitable 50% fixed and 50% variable split.

FFPC noted that both the Residential and Street Lighting class fixed charges are within the floor and ceiling boundaries. FFPC stated that both monthly fixed charges increased to adjust for increases to the rate specific revenue requirement.

FFPC noted that the fixed charges for the remaining three classes all exceed the maximum ceiling for fixed charges. FFPC explained that this was due to the maintenance of the current fixed to variable split for these classes and the impact of changes in the class specific revenue requirements.

FFPC submitted that the Town of Fort Frances, which is the total service territory of FFPC, is experiencing no growth and a stalled economy due to the closure of the local paper mill. FFPC stated that it has maintained the current fixed and variable monthly charge ratios to maintain distribution revenue that could be reduced as a result of its aging demographic, vacant housing and business closures.

Discussion and Submission

Board staff notes that the fixed charges for the GS<50kW and USL customer classes are proposed to either move further away from the ceiling or to exceed the ceiling having been below it before. In the case of the GS 50-4,999 kW class the existing monthly charge was already above the ceiling and the proposed charge moves it closer to the ceiling.

In the normal course, Board staff would suggest to revise the fixed/variable splits in order to avoid raising the fixed charges in the GS<50 kW and USL classes. However, this would mean raising the variable component of the inter class allocation for each of these classes, one of which is a class which may continue to be impacted by the economic situation faced by the Town of Fort Frances. Board staff accepts FFPC's decision to maintain the current fixed/variable splits at the present time. Board staff also notes that for typical rate class consumption levels, the total bill impacts for all rate classes are below the 10% level.

8.4 Are the proposed Total Loss Adjustment Factors appropriate for the distributor's system and a reasonable proxy for the expected losses?

Loss Factors

Background

FFPC is proposing to use a 2014 total loss factor for secondary metered customers< 5,000 kW of 1.0470, which is the average of the previous five historic years. This represents a slight increase from the currently approved level of 1.0406. The proposed distribution loss factor is 1.0365%. FFPC stated that pursuant to the Filing Requirements, it is not required to provide an explanation of its loss adjustment factor as it is less than 5% and did not do so. FFPC stated in its Application that it is not an embedded distributor.

Discussion and Submission

Board staff accepts FFPC's proposed 2014 total loss factor for secondary metered customers< 5,000 kW of 1.0470 and distribution loss factor of 1.0365%.

8.5 Is the proposed forecast of other regulated rates and charges including the proposed Retail Transmission Service Rates appropriate?

Retail Transmission Service Rates ("RTSR")

Background

FFPC filed updated RTSRs on April 17, 2014.[47] The current and forecast wholesale cost is calculated using the Uniform Transmission Rates which became effective January 1, 2014.

Discussion and Submission

Board staff accepts FFPC's proposed RTSR's as listed below.

[47] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on April 4, 2014,* p.23 VECC #8.

Rate Classes	RTSR Network	RTSR Connection
Residential ($/kWh)	$0.0071	$0.0017
GS < 50 kW ($/kWh)	$0.0064	$0.0015
GS 50 to 4,999 kW ($/kW)	$2.6255	$0.6308
Street Lighting ($/kW)	$1.9801	$0.4878
Unmetered Scattered Load ($/kWh)	$0.0064	$0.0015

8.6 Is the proposed Tariff of Rates and Charges an accurate representation of the application, subject to the Board's findings on the application?

Low Voltage ("LV") Charges

Background

FFPC states that it does not host any utilities within its service area, nor is it an embedded distributor. Therefore, it is not proposing any low voltage charges.

Discussion and Submission

Board staff accepts FFPC's position on this matter.

Transformer Ownership Allowance

Background

FFPC is proposing to maintain the current ($0.60) Transformer Ownership Allowance.

FFPC submits that in order to ensure it collects the proposed distribution revenue assigned to the rate class, which provides a transformation 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.

Discussion and Submission

Board staff notes that the Transformer Ownership Allowance is a credit payable to those customers within an applicable class that own their own transformation facilities with the estimated credit to be paid being then factored in as an addition to the revenue requirement to be recovered through distribution rates for the applicable customer class.

Board staff accepts FFPC's proposal to maintain the current Transformer Ownership Allowance and its treatment.

9. Accounting

9.1 Are the proposed deferral accounts, both new and existing, account balances, allocation methodology, disposition periods and related rate riders appropriate?

9.2 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified, and is the treatment of each of these impacts appropriate?

Deferral and Variance Accounts

Background

FFPC is proposing to dispose of the following December 31, 2012 DVA balances, as shown below:

		Proposed DVA Balances for Disposition	
Group 1			
	1580	RSVA - WMSC	-$ 99,297.00
	1584	RSVA - Network	$ 1,588.00
	1586	RSVA - Connection	-$ 156.00
	1588	RSVA - Power excl. GA	$ 56,077.00
	1589	RSVA - GA	-$ 224,583.00
	1590	Reg. Asset Bal.	-
Sub-Total			-$ 266,371.00
Group 2			
	1508	OEB Cost Assess.	$ 8,451.00
	1508	IFRS Transition	$ 27,183.00
	1531	Ren. Gen. Conn.	$ 1,966.00
	1582	RSVA One Time	$ 6,891.00
	2425	Other Deferred Credits	-$ 6,144.00
Sub-Total			$ 38,347.00
	1568	LRAM Variance Account	$ 27,572.00
Total			-$ 200,454.00

FFPC has requested disposition of its deferral and variance account (the “DVAs”) balances as of December 31, 2012, and interest forecasted to April 30, 2014. The total amount requested for disposition, including forecasted interest for all Group 1, Group 2 DVAs and Account 1568 LRAMVA is a credit of $200,454, as is shown in the above table. This amount includes the Global Adjustment credit balance of $224,583 which is proposed to be refunded as a separate rate rider to the non-RPP customers only.

Discussion and Submission

1. Balances Proposed for Disposition

Board staff does not have any concerns with the balances proposed for disposition with the exception of the balance in the LRAM Variance Account 1568 which should only include the LRAMVA balance of $5,050, but which also includes the LRAM amount of $22,523 which Board staff submits should not be recorded in an account. All DVA balances as of December 31, 2012 matched the RRR 2.1.7 filed with the Board, except for Account 2425, Other Deferred Credits. In response to Board staff interrogatory,[48] FFPC indicated that Account 2425 was used in error to record a credit amount of $105,480 in the RRR filing. In response to a Board staff Teleconference question,[49] FFPC confirmed that it will correct the RRR 2.1.7 filing to show the correct credit balance of $6,144 amount. The amount requested for disposition is with respect to shared tax savings approved in FFPC's IRM proceedings EB-2011-0146 and EB-2012-0083.

2. <u>Account 1508 – Sub-account IFRS Transition Costs</u>

As part of the disposition request of -$200,454, FFPC has proposed disposition of its IFRS Transition Costs of $27,183 which includes forecasted interest to April 30, 2014. FFPC has also stated that it is deferring implementation of IFRS until January 1, 2015, and that costs may be incurred in the future as FFPC completes its transition to IFRS. FFPC has also requested continuation of IFRS transition costs sub-account 1508.

Board staff notes that the Board's general policy and practice is not to dispose of the Account 1508 Sub-account IFRS Transition Costs until the distributor has completed its adoption of IFRS for financial and regulatory purposes and so has a complete record of such costs to review. Also, as per the October 2009 FAQ #1 and FAQ #2, an Applicant must file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance, in its next cost of service rate application immediately after the IFRS transition period.

In response to a Board staff interrogatory,[50] FFPC explained that it has made changes to its capitalization and depreciation policies effective December 1, 2013 (The December

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[48] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 9 Interrogatories May 22, 2014,* p.1 9-1-Staff-34.
[49] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014,* p.28 9-1-Staff-48.
[50] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 9 Interrogatories May 22, 2014,* pp.2-3 9-1-Staff-35.

1 date appears to be a typographical error, as all other evidence, including the Appendix 2-EE, calculation of Account 1576, Accounting Changes under CGAAP indicate that the policy changes were made effective January 1, 2013) and the remaining work to move to IFRS is minimal and is expected to be done with internal staff with minimal to zero incremental costs booked to Account 1508. FFPC reiterated its proposal to recover the IFRS Transition Costs since most of the costs have been incurred to move to IFRS.

Board staff does not have any issues with FFPC's proposal to dispose of the balance in Account 1508, Sub-account IFRS Transition Costs. However, it is not clear whether FFPC has any more costs booked in this account for the 2013 calendar year. As the balance being proposed for disposition is based on the December 31, 2012 balances, Board staff recommends that FFPC identify the 2013 costs, if any, in its reply submission and if the Board is satisfied with the nature and quantum of these costs, they can be added to the overall balance to be recovered on a final basis.

3. Account 1518, Retail Cost Variance Account for Retail Services; and Account 1548, Retail Coat Variance Account for Service Transaction Requests (RCVAs)

FFPC stated that it does not track RCVA variances in its accounts. In response to a Board staff interrogatory,[51] FFPC further stated that the amounts are immaterial and not justified to be tracked on the basis of cost benefits. FFPC also provided estimates of costs and actual revenues for the Retailer accounts in response to the staff interrogatory. This analysis shows that annual variances in each account on average would be approximately a credit of $80.

While every rate regulated LDC should follow the procedures outlined in the APH, Board staff accepts that any balances recorded in the accounts would have been immaterial and therefore no disposition is warranted.

4. Account 1592, PILs and Tax Variance for 2006 and Subsequent Years

[51] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 9 Interrogatories May 22, 2014,* p.4 9-1-Staff-36.

FFPC has requested an exception from recording any tax variances in Account 1592 due to its not-for-profit status and rate minimization strategy.

Board staff notes that FFPC had Shared Tax Savings Adjustments for each year in its 2012 and 2013 IRM of approximately $3,000. In response to a Board staff interrogatory,[52] FFPC was asked that given these 2012 and 2013 savings, why FFPC believed that going forward there would be no tax variances that would need to be captured in account 1592. FFPC responded that for the 2014 test year, the PILs and tax rate are assumed to be zero and as FFPC is a not-for-profit entity, it assumed that the tax rate will remain at zero in the future, resulting in no tax variances.

Given this unique circumstance in which there is no provision for taxes included in the revenue requirement, Board staff agrees that recording an amount in Account 1592 is not relevant.

5. Account 1592 PILs and Tax Variance for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs)

FFPC did not track the tax savings variance with respect to HST ITCs. According to FFPC, it is a “not-for-profit” entity, and its auditors advised it that an 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. FFPC has sought an exemption from tracking of this variance from the July 1, 2010 introduction of HST and all future variance tracking.

FFPC further stated that it is in an accumulated deficit position and any further variance disposition would result in further financial burden that would undermine future capital projects and customer service.

[52] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 9 Interrogatories May 22, 2014,* pp.5-6 9-1-Staff-37.

Board staff does not support an exemption from tracking variances in this account. However, given the rate minimization strategy followed by FFPC since 2006, and the likely immaterial amounts that would result from tracking further credits in the form of ITCs, Board staff does not have concerns with a $0 disposition. Board staff does note however that a distributor cannot unilaterally decide not to follow the APH. In the future, FFPC should endeavour to follow all applicable accounting direction, or in the alternative, to seek guidance from the Board in a timely fashion, if required.

6. Disposition Term

According to the Board report EB-2008-0046[53], the default disposition period used to clear the account balances through a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

FFPC has proposed a two-year term for both DVA rate riders. The evidence filed by FFPC indicates that the default term of one year would create financial hardship for FFPC.

Board staff has no issues with the proposed two year term, as the credit balance refund of $200,453 is more than 10% of the revenue requirement of FFPC.

CDM & LRAMVA

Background

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on April 26, 2012 outline the information that is required when filing an application for lost revenues in relation to both pre-2011 CDM activities (i.e. LRAM) and 2011-2014 CDM activities (i.e. LRAMVA).

[53] *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (EDDVAR)

LRAM for pre-2011 CDM Activities

FFPC requested approval for an LRAM recovery in relation to pre-2011 CDM program savings of $22,523 arising from the recovery of lost revenues from persisting CDM savings from 2006-2010 CDM programs in 2011, 2012 and 2013.

LRAMVA for 2011-2014 CDM Activities

FFPC also requested approval of an LRAMVA recovery in account 1568, specifically $5,050 in relation to energy savings from new programs deployed in 2011 and 2012 that will contribute to FFPC's 2011-2014 CDM Targets. FFPC requested that its LRAMVA amount be recovered as part of the standard deferral and variance account recovery process on the basis that it has verified results from the OPA for 2011 and 2012.

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.

Discussion and Submission

LRAM for pre-2011 CDM Activities

Board staff notes that FFPC last applied for LRAM approval for savings related to pre-2011 CDM activities with its 2012 IRM application, where it received approval for its LRAM applicable to 2006 to 2010 CDM programs for the years 2006 to 2010. Board staff further notes that as FFPC hasn't rebased since 2006, it has not had an opportunity to include any of its CDM effects in its load forecast and therefore all lost revenues are eligible for recovery. On this basis, Board staff supports the recovery of FFPC's requested LRAM amount of $22,523.

Board staff submits that as outlined in Section 13.6 of the CDM Guidelines, LRAM for pre-2011 CDM activities (i.e. CDM programs delivered between 2005 to 2010 and before issuance of the CDM Code) should have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application. Going forward, FFPC should not be eligible to recover any additional LRAM amounts for pre-2011 CDM activities as these effects are expected to be captured in FFPC's updated load forecast.

LRAMVA for 2011-2014 CDM Activities

With respect to FFPC's lost revenues related to its 2011-2014 CDM activities that contribute toward its CDM targets, Board staff submits that FFPC has appropriately relied on its final 2011 results as calculated by the OPA for calculating its LRAMVA balance in relation to 2011 CDM program savings in 2011 and persisting savings in 2012. Board staff supports the recovery of FFPC's requested LRAMVA balance of $5,050.

Smart Meters

Background

FFPC noted that its EB-2012-327 rate order, effective November 1, 2012, ordered the recovery of its smart meter costs from all metered rate classes, including the GS>50kW class. The approved SMDR and SMIRR rate riders are shown below:

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 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 this Application.

FFPC is seeking disposition of its stranded meter costs. The net book value of the stranded conventional meters at December 31, 2013 was $80,186[54], as revised in response to a Board staff interrogatory. FFPC proposed a one-year recovery of this amount from the Residential, GS<50 kW and GS>kW classes to align with the cost recovery approved in FFPC's EB-2012-0327 rate order.

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[54] EB-2013-0130 *Fort Frances Power Corporation Response to Issue 9 Interrogatories May 22, 2014,* p. 7 9.1-Staff-38.

The proposed Stranded Meter Disposition Rate Riders per customer, as revised in the same Board staff interrogatory are outlined in the table below:

Stranded Meter History and Cost Allocation								
Rate	# Meters in Service	2008	2009	2010	2011	2012	2013	Stranded Meter Disposition Rate Rider Per Customer
								Monthly Charge
Residential	3283	$61,001	$56,192	$49,998	$44,287	$38,578	$33,704	**$0.86**
GS <50 kW	422	$66,471	$61,020	$53,975	$47,459	$40,944	$35,409	**$6.99**
GS >50 kW	47	$18,795	$16,204	$15,317	$13,419	$12,694	$11,073	**$19.63**
					$0			
Net Book Value	3752	**$146,267**	**$133,416**	**$119,290**	**$105,165**	**$92,216**	**$80,186**	
Accumulated Amortization		*$244,323*	*$258,449*	*$272,575*	*$286,700*	*$299,649*	*$311,679*	
Gross Book Value		$390,590	$391,865	$391,865	$391,865	$391,865	$391,865	

Stranded meter cost recovery, as per section 3 of O.Reg. 426/06 is generally restricted to the Residential and GS<50 kW classes, but is subject to the Board's discretion. A Board staff teleconference question asked FFPC to place on the record of this proceeding the rationale provided by FFPC for the recovery of smart meter costs from the GS>50kW class (which was approved by the Board in that proceeding) and based on this response and other reasons FFPC may have had to provide a justification as to why a stranded meter cost recovery from this class is justified.[55]

FFPC responded that it sought to recover stranded meter costs from the GS>50kW rate class to ensure that all of FFPC's customers are treated without benefit or burden and that as the GS>50kW rate class has shared in the benefits of Smart Meter technology, it should also be responsible for a proportionate share in the capital replacement cost involved. Second, FFPC noted that its customers can migrate between the two general service classes and therefore seeking recovery for stranded meter assets from all metered rate classes eliminates the chance of rate cross-subsidizing. Finally, FFPC stated that without the stranded meter recovery from the GS>50kW rate class, FFPC would be unable to recover these amortized capital costs creating a loss in capital recovery.

Discussion and Submission

Board staff accepts the stranded meter treatment proposed by FFPC in this Application as it is consistent with the approach taken by the Board in EB-2012-0327 and the

[55] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014,* pp. 28-31 9.1-Staff-49.

evidence provided in support of its proposed approach, as modified by its responses to Board staff interrogatories, in this Application.

10. Other Matters

Background

FFPC requested an effective date for rates of May 1, 2014.

Discussion and Submission

Board staff notes that FFPC's application was due to be filed by October 1, 2013, but that a complete version was not filed with the Board until February 14, 2014, which is a delay of four and a half months. Board staff further notes that subsequent to the filing of the application FFPC filed all required material by the dates set out in the Board's Procedural Orders. Board staff accordingly submits that an effective date for rates of July 1, 2014 would be appropriate.

- All of which is respectfully submitted –

Appendix 1

Historic Changes in FFPC's Capital Spending Compared to Forecast Levels[56]

FFPC Historical Capital Spending ($000)								
	2006	2007	2008	2009	2010	2011	2012	**Avg. 2006-2012**
Category								
System Access	0	0	0	0	0	3	41	6.3
System Renewal	191	130	154	153	166	133	165	156.0
System Service	43	43	16	6	80	1	0	27.0
General Plant	100	21	17	118	277	9	16	79.7
								0.0
Total Expenditure	335	194	187	278	523	145	222	**269.1**
% Change		-42.1	-3.6	48.7	88.1	-72.3	53.1	
FFPC Forecast Capital Spending ($000)								
	2013	2014	2015	2016	2017	2018	**CHG.2014/ 2012**	**Avg. 2014-2018**
Category								
System Access	37	422	40	20	45	12	381	107.8
System Renewal	150	254	419	504	531	361	89	413.8
System Service	55	49	142	60	58	15	49	64.8
General Plant	157	97	76	76	33	311	81	118.6
Total Expenditure	399	820	676	660	667	698	598	**704.2**
% Change		105.5	-17.6	-2.4	1.1	4.6	269.4	

[56] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 20, 2013, Exh 2/Tab3/Sch 1, p.4*