



Ontario Energy Board Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2016-0085

INNPOWER CORPORATION

Application for electricity distribution rates and other charges
beginning July 1, 2017

BEFORE: Allison Duff
Presiding Member

Lynne Anderson
Member

Michael Janigan
Member

March 8, 2018

TABLE OF CONTENTS

1	INTRODUCTION AND SUMMARY.....	1
2	THE PROCESS	3
3	DECISION ON ISSUES	5
3.1	CAPITAL ADDITIONS.....	5
3.2	DISTRIBUTION SYSTEM PLAN	6
3.3	RATE BASE – CORPORATE HEADQUARTERS AND OPERATIONS CENTRE	7
3.4	WORKING CAPITAL	12
3.5	COST OF CAPITAL.....	12
3.6	LOAD FORECAST	13
3.7	REVENUES AND COSTS RELATING TO AFFILIATE - INNSERVICES.....	14
3.8	OPERATIONS, MAINTENANCE & ADMINISTRATION EXPENSES	18
3.9	PAYMENTS IN LIEU OF TAXES.....	25
3.10	COST ALLOCATION AND RATE DESIGN.....	25
3.11	RETAIL TRANSMISSION SERVICE RATES & LOW VOLTAGE RATES....	28
3.12	DEFERRAL AND VARIANCE ACCOUNTS	29
3.13	RATE RIDERS.....	32
3.14	OTHER OPERATING REVENUE	34
3.15	INNPOWER’S COLLECTION PROCESS	38
3.16	EFFECTIVE DATE.....	40
4	IMPLEMENTATION.....	42
5	ORDER	43
	SCHEDULE A.....	45

1 INTRODUCTION AND SUMMARY

This is the Decision of the Ontario Energy Board (OEB) to finalize rates for InnPower Corporation (InnPower) for 2017.

InnPower filed an amended cost of service application with the OEB on May 11, 2017 under section 78 of the *Ontario Energy Board Act, 1998 (Act)*, for approval to change the rates it charges customers for electricity distribution effective July 1, 2017.

InnPower provides electricity distribution services to approximately 16,000 customers in the Town of Innisfil and the lands located in South Barrie. InnPower was formerly Innisfil Hydro Distribution Systems Limited (IHDSL) incorporated in 2000 with a Board of Directors responsible to the sole shareholder, the Town of Innisfil. IHDSL changed its name to InnPower Corporation in January 2015. InnServices Utilities Inc. (InnServices) was incorporated as a municipal services corporation in 2015 with responsibility for the water and wastewater services formerly provided by the Town of Innisfil. InnPower currently provides the water and waste water billing and financial services for InnServices. InnPower and InnServices also share a CEO.

InnPower proposed to increase its rates based on a projected 2017 test year revenue requirement of \$10.955 million. For a typical residential customer with monthly consumption of 750 kWh, the total bill impact would be an increase of about 6.4%.¹

The OEB hosted two community meetings regarding InnPower's 2017 application in Innisfil on March 9, 2017. Approximately 300 customers attended the meetings, and 41 customers filed written comments. Subsequent to the community meetings, InnPower updated its application by reducing its proposed rate increase and deferring its proposed effective date to July 1, 2017.

The OEB's findings in this Decision are summarized as follows:

- Approved 2017 capital additions of \$4.4 million as proposed
- Addition to rate base of \$11.141 million for the new Corporate Headquarters and Operations Centre, less accumulated depreciation

¹ As a result of this Decision, the total bill impact will be lower. The updated total bill impact will not be available until InnPower completes its draft rate order

-
- Approved OM&A budget of \$5.317 million, a reduction of \$0.673 million to the proposed budget
 - Recognition of affiliate revenue of \$757,539 and affiliate expenses of \$704,939 associated with InnServices

InnPower filed a settlement proposal reflecting a complete settlement for the charge to be applied to other parties attaching to InnPower's poles. The OEB accepts the pole attachment settlement proposal (Schedule A).

2 THE PROCESS

The OEB's policy for rate setting is set out in a report of the OEB entitled *A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*². Subsequently, the OEB issued the *Handbook for Utility Rate Applications* (Handbook) which expanded the Renewed Regulatory Framework (RRF) and provides for three alternative rate-setting methods that are available to electricity distributors: Price Cap Incentive Rate-setting (Price Cap IR), Custom Incentive Rate-setting (Custom IR) and Annual Incentive Rate-setting Index.

InnPower filed a Custom IR application on June 6, 2016 to change rates effective January 1, 2017. The OEB found this application to be incomplete. InnPower decided to change its application to a Price Cap IR application, which was filed on November 28, 2016. With the Price Cap IR option, rates for 2017 are set based on a forecast of costs and sales volumes. These 2017 rates are then adjusted mechanistically each year for four years through a price cap adjustment based on inflation, industry productivity and the OEB's assessment of InnPower's efficiency. This application is for the setting of 2017 rates based on a detailed review of InnPower's forecasts.

The OEB issued a Notice of Application on February 22, 2017 inviting parties to apply for intervenor status. Parties that were granted intervenor status in this proceeding are Rogers Communications Canada Inc. (Rogers), School Energy Coalition (SEC), and Vulnerable Energy Consumers Coalition (VECC).

The OEB hosted two community meetings regarding InnPower's 2017 rate application in Innisfil on March 9, 2017. At the meetings and in written comments, customers expressed concerns about high electricity rates, including some comments regarding InnPower's corporate governance and lack of regard for cost control. Subsequent to the community meetings, InnPower filed an amended application with the OEB on May 11, 2017, reducing its requested rate increase and delaying the effective date for the rates to July 1, 2017.

The OEB issued Procedural Order No. 1 on May 16, 2017, which provided for the filing of interrogatories and responses. Procedural Order No. 2 was issued on May 26, 2017

² Report of the Board: *A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*, October 18, 2012

to provide further notice of this application for specific customer groups and allow for additional related interrogatories and responses.

Procedural Order No. 3 was issued on September 1, 2017 in which the OEB established a process for developing a draft issues list and set dates for a technical conference and an oral hearing. In addition, the OEB expressed its intent to establish separate procedural steps regarding InnPower's proposed pole attachment and microFIT charges.

An oral hearing was held on October 3rd and 4th, 2017 regarding all issues raised in the application, except for the pole attachment and microFIT charges. Written submissions were filed by SEC, VECC, OEB staff and InnPower.

Pole Attachment and microFIT Charges

In Procedural Order No. 3, the OEB directed InnPower to give further notice of its application to customers or customer groups that would be affected by the proposed pole attachment and microFIT charges. To avoid further delay to the hearing schedule while further notice was served, the OEB established separate procedural steps for the pole attachment and microFIT charges in its Decision and Procedural Order No. 7 issued November 10, 2017.

In its Decision and Procedural Order No. 7 issued on November 10, 2017 the OEB indicated it would not consider a change to the microFIT charge of \$5.40. However, the OEB would consider a change to the current pole attachment charge of \$22.35. The OEB established a process related to the pole attachment charge for the filing of interrogatories and responses, and a settlement conference.

A settlement conference was convened on January 8, 2018 and January 9, 2018 related to the charge for pole attachments. A settlement proposal was filed by InnPower on February 2, 2018 reflecting a complete settlement (Schedule A). Parties to the settlement proposal are InnPower, SEC, VECC and Rogers. A submission from OEB staff on the settlement proposal was filed on February 9, 2018. The parties to the settlement proposal filed a joint reply submission on February 23, 2018.

3 DECISION ON ISSUES

3.1 Capital Additions

InnPower's actual and forecast capital additions are shown in Table 1.

Table 1 – Net Capital Additions³

Actual \$'000					Forecast \$'000				
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
3,818	4,751	5,031	15,263	4,548	4,405	5,176	6,435	5,795	5,768

Table 1 includes the increase in capital contributions for 2017 through 2021, which were updated at the Technical Conference. As a result, the net capital additions (net of capital contributions) for 2017 through 2021 have decreased from the pre-filed evidence. The impact on the 2017 rate base is to lower net capital additions for 2017 by \$2.284 million⁴. Five projects in the Distribution System Plan (DSP) that were previously categorized as System Service in 2017 were re-categorized as System Access projects, as they related directly to new subdivision developments. InnPower submitted that capital contributions totaling \$2.284 million should have been assessed against these projects. As a result, InnPower's revised net capital addition proposal for 2017 is \$4.4 million.

SEC did not object to InnPower's proposed capital additions. However, SEC noted that the capital spending per customer, excluding the new Corporate Headquarters and Operations Centre, increased by 111% over the last nine years such that InnPower's net capital additions per customer were 56% higher than the industry average in 2016.

VECC sought to have the 2017 capital additions updated to actuals. OEB staff submitted that \$4.4 million of capital additions should be approved using an "envelope" approach, and that a more up-to-date forecast of capital additions was not required. OEB staff indicated that the 2017 rate base should be updated for items such as the revised lower cost of power and a higher amount of amortized capital contributions.

³ 2017_Filing_Requirements_Chapter2_Appendices TC_20170920. Appendix 2-AB

⁴ InnPower_transcript_vol1_TC_20170912, page 87

In reply submission, InnPower stated that if the OEB prefers to use a more up-to-date forecast of capital additions, there should be a comprehensive review of the entire capital program to accurately reflect both increases and decreases. InnPower also indicated that it plans to commence developing a new business plan after this application is completed.

Findings

The OEB approves InnPower's forecast net capital additions of \$4.4 million for 2017. While the OEB notes that these capital additions are directionally congruent with the DSP, InnPower will need to review its capital additions and revise the Distribution System Plan to align with expectations arising from the implementation of a new business plan.

3.2 Distribution System Plan

InnPower provided a Distribution System Plan (DSP) as part of its application, including appendices related to its Asset Condition Assessment which was completed by METSCO Energy Solutions (METSCO).

OEB staff submitted that InnPower had not utilized sufficient pacing and prioritization in planning its capital investments and this should be corrected going forward. During the Technical Conference, InnPower confirmed that its pacing and prioritization efforts have been focused on 2017 and not the years beyond 2017. However, InnPower indicated in its reply submission that OEB staff cited little evidence to support this statement of pacing and prioritization.

OEB staff submitted that InnPower should investigate initiatives that could reduce costs, such as non-destructive testing of cables. In its reply submission, InnPower indicated that it is willing to assess the use of non-destructive cable testing as part of its project prioritization process.

Regarding InnPower's Asset Condition Assessment, VECC argued that InnPower's assessment has a problem common among utilities in that the data from which assessments are made is simply plant age, adding little new information to the existing known depreciation life of assets. VECC submitted that METSCO has not completed an assessment of the availability, reliability or relevance of the data provided to it by InnPower. VECC advised that the OEB needs to approach the recommended outcomes

in InnPower's DSP with caution and an asset data analysis must be completed by InnPower at the time of its next DSP or Asset Condition Assessment.

In reply, InnPower disagreed that the Asset Condition Assessment was flawed, or in any way misleading.

Findings

The DSP provides useful information to evaluate the performance of the distributor in meeting its performance objectives, and should be updated with the new business plan. This is particularly the case where the evidence of InnPower is that it significantly reduced important System Renewal expenses over the last term. These reductions were ostensibly to accommodate System Access demands and to mitigate potential impacts of distribution rates on customers.

The OEB accepts that METSCO's evidence satisfied concerns about pacing and the asset condition assessment. The OEB expects that InnPower's new business plan and DSP will adhere to the principle of "growth will pay for growth" expressed by its witnesses in this proceeding.

3.3 Rate Base – Corporate Headquarters and Operations Centre

InnPower proposed a 2017 rate base of \$53.1 million and depreciation expense of \$2.7 million⁵.

InnPower submitted that a key component of its revenue deficiency relates to the new Corporate Headquarters and Operations Centre (Building) to be added to rate base in 2017. InnPower provided evidence that the actual total cost of the Building project was \$13,491,210. This includes costs of \$13,246,704 that were submitted by InnPower in its 2015 Incentive Rate-setting Mechanism (IRM) application⁶ which included an Incremental Capital Module (ICM application), as well as an additional \$244,506 in Building-related costs for furniture and improvements submitted in this application. InnPower maintains that the need for, and prudence of the Building was approved by the OEB in the ICM application.

⁵ October 10, 2017 InnPower_Cross Reference Document_20171011

⁶ EB-2014-0086

The OEB's approval of the Building in the ICM application followed the presentation of a settlement proposal that provided that the amount of \$10,896,704 was prudent for inclusion in the ICM (ICM settlement). The revised amount reflected a reduction of \$2,350,000 from InnPower's (then IHDSL) ICM application. The OEB-approved ICM settlement also provided that rental income for space in the Building in excess of InnPower's requirements would be included to reduce revenue requirement at the time of the next rebasing application on a prospective basis.

InnPower submits that the reduction of \$2.35 million in the ICM settlement was made to account for the exclusion of the available rental space in the Building from ICM recovery. InnPower maintains that the OEB's acceptance of the \$10,896,704 in the ICM settlement did not include the rental space. InnPower asserts that its actual costs of \$13,491,210 to date for the Building, including the rental space, are prudent.

In this application, InnPower proposes to reduce the Building capital addition allowed into rate base by \$2.35 million which they argue is the portion of the Building related to the rental space. The reduced amount would mean that the cost related to the available rental space would not be included in rate base. InnPower proposes to retain all rental revenue and be responsible for rental expenses for this portion of the Building. InnPower also indicated that the actual leasing of the extra space was significantly delayed. A lease was only signed in September 2017, with forecasted leasing revenue dropping to \$33,000.

OEB staff submitted that the \$2.35 million reduction made as a result of the ICM application should be a permanent adjustment to the capital amount allowed in rate base for the Building, and any rental revenue from surplus space should be used to reduce InnPower's revenue requirement in accordance with the ICM settlement. In addition, OEB staff rejected the inclusion of further capital additions of \$244,506 in rate base which are in excess of the amount in the ICM settlement.

OEB staff's submission also observed that InnPower had not clearly shown where in its evidence the old building costs had been removed from rate base, which should have been dealt with in accordance with the ICM settlement. OEB staff requested that InnPower confirm in its reply submission that the specific amounts related to the old building were removed from rate base and indicate where in the evidence this reduction is reflected. InnPower did not respond to OEB staff's requests in its reply submission.

SEC submitted that the OEB should accept the ICM-reduced cost of the Building in rate base as well as InnPower's proposal to retain revenues for the rental of excess space.

VECC indicated that it technically agreed with OEB staff, but accepted InnPower's approach to the rental space.

Findings

The OEB finds that its decision related to the ICM application (ICM decision) approved the ICM settlement which established the prudence of a specific capital amount of \$10,896,704 for the Building. The OEB determines that the \$10,896,704 was inclusive of building space available for rent that was and remains in excess of the operational requirements of InnPower.

The ICM settlement approved by the OEB in the ICM decision acknowledged the parties' acceptance of InnPower's need for a new Building. The relevant sections of the ICM settlement fixing the capital cost amount of the Building as prudent for inclusion in the ICM is set out as follows:

1c) Prudence

For the purposes of settlement, the Parties agree to an incremental capital reduction of \$2,350,000 from the submitted capital amount of \$13,246,704. The Parties agree that the revised capital amount of \$10,896,704 is prudent considering:

- The current square footage and operational requirements of IHDSL;
- A reasonable allowance for future staffing growth expected over the next 20 years due to IHDSL's growth predictions; and
- Reasonable comparisons with industry Distributors who have recently constructed new administration and /or operations facilities (Enersource, Powerstream and Waterloo North Hydro) considering current market construction rates.

As discussed below, administrative and/or operational space that is in excess of IHDSL current requirements will be available for lease. Related leasing income will be included at the time of IHDSL's next rebasing application on a prospective basis. This arrangement provides a means of protecting IHDSL's customers from costs associated with the difference between the utilities needs over time and the total area available at the new Administration and Operations Centre....

3. What is the appropriate treatment of leasing revenues for the new Corporate Headquarters and Operations Centre?

In response to OEB Staff IR – 12, IHDSL requested a Deferral and Variance Account (“DVA”) to record any leasing revenues it will receive for the new Corporate Headquarters and Operations Centre. The Parties agree that IHDSL will be able to rent/lease any excess square footage at the new Corporate Headquarters and Operations Centre. As of the date of filing, IHDSL is negotiating with two parties for leasing square feet at market rates. It is anticipated that the sites will be leased by July 2015.

IHDSL has indicated that it expects additional OM&A costs for the Corporate Headquarters and Operations Centre, above those incurred at the 2073 Commerce Park Drive facilities (IRR EP 4a – 4b).

For the purposes of the settlement, the Parties agree that since an ICM is intended to recover the revenue requirement associated with capital additions only, there will be no DVA to record leasing revenues during IHDSL’s IRM term. IHDSL does agree to include revenue off-sets from leasing revenues in its next Cost of Service or Custom IR application.⁷

The above provisions set out that the reduced ICM amount of \$10,896,704 is prudent, reasonable and sufficient considering the square footage and operational requirements of InnPower at the time of the ICM settlement and for 20 years thereafter. This reduced amount also allowed for reasonable space for future staffing growth, and puts the Building costs in line with other distributors’ facilities. To alleviate the burden on customers for the cost of the portion of the Building that would not be used by InnPower but could accommodate future growth, it was agreed that rental revenue for that portion of the Building would be included in the next rates application as an offset to revenue requirement.

In this proceeding, InnPower now argues that the \$2.35 million reduction to the ICM amount was simply the result of excluding the Building space surplus to its needs that would be available for rent. The OEB cannot accept InnPower’s contention as it is not supported by the plain meaning of the relevant sections of the ICM settlement referenced earlier in this Decision. The OEB’s finding is also supported by the following analysis:

⁷ EB-2014-0086, Decision and Rate Order, Appendix A (Settlement Proposal), December 4, 2014, pages 9 and 12

- Paragraph 1c of the ICM settlement does not indicate that the \$2.35 million reduction in Building costs is a result of excluding that amount as the capital cost attributable to the portion of the Building that is available as rental space.
- Sections 1c and 3 of the ICM settlement contemplate revenue from renting out space that is surplus to InnPower's operations as an offset benefitting customers. There is no mention of a condition precedent to recognizing such revenue offsets.
- There is no calculation or rationale in the ICM settlement equating the ICM reduction with rental space costs as justification for the exclusion of the quantum (\$2.35 million) from the ICM, nor is there any analysis of the effects on rate base of the potential future use of all or some of the rental space.
- InnPower's position in this application implicitly argues that the prudence of the full Building cost of \$13.5 million was accepted by all parties in the ICM application. Such an argument conflicts with the comparison of other distributors' costs referenced in the ICM settlement as a reason for the \$2.35 million reduction.
- As the Building was almost completed, total costs, including those for excess space, were largely known at the time the parties were negotiating the settlement proposal, and subsequent approval of the settlement proposal by the OEB.

For the foregoing reasons, the OEB finds that the ICM decision approved the amount of \$10,896,704 as prudent for the Building capital additions. This included the cost of any Building space that was not needed for InnPower's current use and was available for lease. Accordingly, rent collected for any space not utilized by the utility, now estimated by InnPower to be \$33,000 for 2017, will be a revenue offset until InnPower submits its next rebasing application, at which time it is expected that the revenue offset would be a full year of rental revenue

The OEB adopts the ICM decision as to the need for the Building and the prudent amount to be included in rate base, which was settled at \$10,896,704. The OEB also accepts the capital addition of \$244,506, less accumulated depreciation, claimed for Building costs incurred over and above the ICM amount found to be prudent. The \$244,506 is for furniture and fixtures, costs that were not included in the forecast capital for the ICM. The OEB finds that this amount should be included in rate base along with the \$10,896,704, less accumulated depreciation.

The OEB directs InnPower to file a revised 2017 rate base and depreciation expense in its draft rate order to reflect the findings in this Decision, including removal of the specific amounts related to the old building (2073 Commerce Park Drive) from rate base, in accordance with the ICM settlement.

3.4 Working Capital

InnPower proposed to use the OEB's 7.5% working capital default rate to calculate its working capital allowance.

Findings

The OEB approves InnPower's proposed use of 7.5% for the calculation of the working capital allowance. The 7.5% is applied to the total of the cost of power plus the OM&A expenses. The OEB accepts InnPower's cost of power calculation methodology⁸ but directs InnPower to update its cost of power for the approved load forecast discussed later in this Decision, and for the Rural or Remote Electricity Rate Protection (RRRP) charge of \$0.0003⁹. InnPower is required to file an updated working capital allowance to reflect the cost of power and OM&A expenses approved this Decision.

3.5 Cost of Capital

InnPower proposed a 2017 weighted average cost of capital of 5.58%. No parties objected.

Findings

The OEB approves a 2017 cost of capital of 5.58% as set out in Table 2.

Table 2 – Weighted Average Cost of Capital 2017

	Capitalization Ratio	Cost Rate
Long-term Debt	56.0%	3.57%
Short-term Debt	4.0%	1.76%
Total Debt	60.0%	3.45%
Total Equity	40.0%	8.78%
Total	100.0%	5.58%

⁸ Undertaking J1.7

⁹ EB-2017-0234, Decision and Order on RRRP charge and DRP, June 22, 2017

3.6 LOAD FORECAST

InnPower proposed a load forecast of 239.6 GWh but revised it to 239.7 GWh after the Technical Conference, based on actual load and customer counts from January to August 2017. InnPower's load forecast relied on a total loss factor of 1.0731 based on ten years of data from 2007-2016¹⁰. InnPower submitted that the proposed load, customer forecast, loss factors, Conservation and Demand Management (CDM) adjustments and resulting billing determinants were appropriate.

VECC had no issues with InnPower's final load forecast or its associated methodology, based on actuals to August 2017 and extrapolated monthly values for the balance of the year.

OEB staff submitted that InnPower's loss factor had improved over time and the total loss factor to be used in calculating the forecast of billed energy should be based on the recent five-year average of 1.0604.

OEB staff also noted that InnPower had used the same five-year total loss factor when calculating bill impacts for secondary metered customers at less than 5,000 kW and on its proposed Tariff of Rates and Charges (Tariff). In reply submission, InnPower agreed that OEB staff's proposed change was reasonable.

Findings

The OEB finds it appropriate for InnPower to revise the load forecast for billed energy by using the recent five-year average of 1.0604 for the total loss factor. The OEB finds that losses based on the ten-year average overstates the recent trend in losses and understates the load forecast. In its reply submission, InnPower indicated that this change was reasonable.

The OEB directs InnPower to revise its 2017 load forecast, updating the billed energy forecast by applying a loss factor of 1.0604 to the purchased energy, consistent with undertaking J1.9, for inclusion in the draft rate order.

¹⁰ "Table 3-8 Conversion of Total System Purchases to Total Billed" included in the update to Exhibit 3 reflected in the August 4, 2017 interrogatory responses, file "InnPower Response IRR_EB-2016-0085_20170804 Renamed"

The OEB also approves the five-year average losses to be used for the loss factor for billing purposes. InnPower already included this five-year average on the proposed Tariff, and in calculating bill impacts for secondary metered customers. The loss factors for billing are approved as follows:

Secondary metered customers at less than 5000 kW	1.0604
Primary metered customers at less than 5000 kW	1.0498

The loss factor for primary metered customers is amended from the 1.0480 proposed by InnPower in its proposed Tariff and bill impacts model filed on September 20, 2017. The approved 1.0498 loss factor is calculated as 1% lower than the loss factor for secondary metered customers, consistent with how it was calculated for the previous Tariff.

3.7 Revenues and Costs relating to Affiliate - InnServices

InnServices is the water and waste water utility for the Town of Innisfil and an affiliate of InnPower. InnPower provides services to InnServices for:

- providing the back office for financial services (Financial Services)
- issuing bills, customer care, and collections (Billing Services)

InnPower updated its forecast for revenues from InnServices for Financial Services to \$346,309¹¹, and revenue for Billing Services to \$245,000 in an undertaking following the oral hearing¹².

SEC submitted that the annual bill for Financial Services of \$346,309 would be substantially higher if costs were allocated fully rather than on an incremental basis. SEC noted that InnPower bills InnServices based on docketed hours spent on the affiliate's work with a standard payroll burden, but no overhead charge for other costs such as work space, computers or administrative support. SEC submitted that the revenue offset for Financial Services should be increased to \$550,000.

¹¹ The \$346,309 is the sum of the following:

- \$232,198 revenue of Financial Services
- \$112,981 additional expected revenue (J1.6)
- \$1,130 administrative fee of 1% (other income)

¹² Undertaking J1.6

SEC submitted that the forecasted revenue for Billing Services of \$245,000 is too low, creating an unfair subsidy provided by InnPower's electricity distribution customers. SEC calculated that InnPower's billing costs were \$1,071,681, yet only \$644,733 of this amount was divided between InnServices and InnPower. In addition, SEC argued that there should be overhead costs associated with the labour costs, yet none were allocated to InnServices. SEC submitted that the revenue offset for Billing Services should be increased by at least \$100,000.

OEB staff submitted that the 2017 revenue requirement should be updated to include the increased amounts of other revenue proposed by InnPower.

In its reply submission, InnPower reinforced its commitment to ensure all affiliate services were priced appropriately and in accordance with the OEB's *Affiliate Relationships Code*. InnPower acknowledged SEC's submission regarding overhead costs and performed an analysis of all general and administrative expenses forecast in 2017. InnPower identified overhead costs attributable to Financial Services of \$40,990 and Billing Services of \$125,240, for an additional \$166,230 in other revenue from InnServices. InnPower clarified that these overhead amounts were in addition to the additional forecast revenues of \$112,981 that were included in the revised \$346,309 Financial Services revenue in accordance with Undertaking J1.6. This amendment would result in a total of \$757,539 in affiliate revenue¹³, including \$245,000 of Billing Services revenue that had already been incorporated into InnPower's forecast of other revenue submitted on September 20, 2017¹⁴.

In addition to these revenues, InnPower charges \$5,000 rent to InnServices for a couple of employees who occupy space in the office building. InnPower confirmed that the rent is \$5,000 for 2017¹⁵, and is based on rates that InnPower bills non-affiliate parties. The revenue for this was included as other operating revenue.

InnPower explained that it used different accounting treatment for Billing Services and Financial Services. Revenue related to Billing Services was included with other revenue. Expenses related to Financial Services were removed from OM&A, rather than included in other revenue (except for a 1% administration fee).

¹³ \$757,539 = \$346,309 for Financial Services + \$245,000 for Billing Services + \$166,230 (125,240 + 40,990) for additional overhead costs related to Billing Services and Financial Services, respectively)

¹⁴ 2017_Filing_Requirements_Chapter2_Appendices TC_20170920, Appendix 2-H, cell H100

¹⁵ Hearing transcript volume 1, page 123. Based on 7 months, \$9,000 per year.

Findings

The OEB finds that InnPower's accounting practices related to affiliate services are inconsistent with the OEB's *Accounting Procedures Handbook*¹⁶ (APH). For example, InnPower accounted for Billing Services and Financial Services OM&A expenses differently. The APH's Uniform System of Accounts requires the use of:

- Account 4375 Revenues from Non Rate-Regulated Utility Operations
- Account 4380 Expenses from Non Rate-Regulated Utility Operations

The OEB is also not clear if InnPower has followed the APH's Article 340, Allocation of Costs and Transfer Pricing.

The net amount from these two accounts is a revenue offset to the revenue requirement. Had InnPower adhered to the APH, non-rate regulated revenues and expenses would be segregated in the above-noted accounts to keep the accounting for the regulated utility clear.

Based on the evidence and InnPower's reply submission, InnPower's proposed 2017 affiliate revenue for Financial Services and Billing Services is \$757,539. The OEB approves this amount for inclusion in Account 4375, Revenues from Non Rate-Regulated Utility Operations, as part of other revenue in 2017 as discussed in the OM&A section of this Decision.

The evidence indicates that InnPower forecast \$1,087,311 for Account 4375, which includes \$245,000 related to Billing Services revenue and \$0 related to Financial Services revenue¹⁷. The OEB directs InnPower in its draft rate order to provide a summary of the updated 2017 amount for Account 4375, reflecting this Decision.

During the oral hearing, InnPower acknowledged that its affiliate transactions were based on incremental costs rather than fully-allocated costs. In its reply submission, InnPower provided an estimate of \$166,230 in overhead costs associated with affiliate services. Unfortunately, this information was provided at the close of the record in InnPower's reply submission, without an opportunity for the information to be tested

¹⁶ Ontario Energy Board Accounting Procedures Handbook, December 2011, Article 220 Uniform System of Accounts

¹⁷ Appendix 2-H, Other Operating Revenue, September 20, 2017

applying fully-allocated costing principles as articulated in the *Affiliate Relationships Code*.

InnPower indicated that it negotiates its service agreements with InnServices. As InnPower and InnServices have the same CEO, the OEB finds any negotiated agreements are inappropriate for the purpose of determining affiliate revenue or expenses. For example, the OEB questions the sufficiency of the 1% administration fee for Financial Services. It also does not appear that InnPower takes into account the use of its assets and a return on its invested capital. For example, while InnPower's breakdown for the cost of issuing bills includes \$75,000 for annual maintenance of the Customer Information System (CIS)¹⁸, this cost does not appear to include sharing the cost of owning the CIS (i.e. depreciation and return on the asset), the system used for producing the bills.

The OEB will undertake an audit of InnPower's affiliate transactions to ensure its allocation of costs and approach to costing and applicable revenue complies with the *Affiliate Relationships Code*. The audit will take into consideration guidance on the approach to fully allocated costing previously issued by the OEB¹⁹, in addition to the APH's Article 340, Allocation of Costs and Transfer Pricing. This audit is expected to be completed so that the audit findings are implemented by InnPower prior to the end of 2018. The OEB is not commenting on InnPower's compliance with the *Affiliate Relationships Code* at this time. This proceeding is addressing the rate-making implications.

The OEB directs InnPower to create two new Group 2 variance accounts. The first variance account will record the difference between the approved forecast of affiliate service revenues of \$757,539 and actual revenues determined as a result of the audit. The approved affiliate forecast is being used to calculate rates for 2017, yet the variance account will be based on the appropriate actual amount, following the OEB audit results.

¹⁸ Undertaking JT2.3

¹⁹ For example, Guideline G-2009-0300 on Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities which includes Appendix A - Fully Allocated Costing Methodology for Non-Rate Regulated Activities

The second variance account will record the difference between the approved forecast of affiliate service expenses approved in this Decision, as discussed in the OM&A section of this Decision, and the fully-allocated costs as determined by the OEB audit.

These two new variance accounts will start effective January 1, 2018, the effective date of this Decision, and continue until the OEB closes the accounts. The OEB will consider annual dispositions of these two new Group 2 variance accounts as part of InnPower's future Price Cap IR applications.

3.8 Operations, Maintenance & Administration Expenses

InnPower proposed a 2017 operations, maintenance and administration (OM&A) budget of \$5.990 million. The proposed budget was 22.5% higher than InnPower's OEB-approved budget in 2013. InnPower's OM&A budgets from 2013 to 2017 are set out in Table 3.

Table 3 – OM&A Budgets 2013-2017 (\$'000)

	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Proposed	Increase over 2013 Approved
OM&A	\$4,890	\$4,995	\$5,225	\$5,558	\$5,689	\$5,990	22.5%

InnPower indicated that its historical OM&A increases were in line with customer growth plus inflation, and driven by factors outside of management's control. InnPower submitted that cost controls had been implemented by its new management team and further reductions to OM&A could not be made at this time.

SEC, VECC and OEB staff did not support the OM&A budget proposed by InnPower.

SEC proposed a budget reduction of \$0.650 million. SEC submitted that a top-down adjustment was required. SEC compared InnPower to other distributors, focusing on customers per FTE and OM&A per customer using the OEB's 2016 yearbook data. SEC concluded that InnPower had 422 customers per FTE compared to the industry average of 553 and calculated InnPower's 2017 OM&A cost per customer to be \$351, which is 28% higher than the average.

SEC submitted that given the size of the affiliate, InnServices, a total cost of \$550,000 for a CEO and back office services is a “bargain”. SEC stated that the revenue offsets for Financial Services should be increased (or administrative costs should be decreased, depending on how InnPower proposes to account for it), by \$550,000, rather than the \$346,309 proposed by InnPower.

VECC proposed an OM&A budget reduction between \$0.500 and \$0.800 million. VECC submitted that there were no outstanding circumstances to warrant an increase above inflation. However, if an OM&A adjustment was made to reflect customer growth, a reduction of \$0.700 million would still be required.

OEB staff proposed an OM&A budget reduction of \$0.420 to \$0.500 million. OEB staff estimated a reduction of \$0.420 million based on an extrapolation of January to July 2017 actuals. OEB staff submitted that a further reduction in OM&A was warranted as InnPower’s revenue deficiency did not appear to be “in touch” with its customers’ concerns regarding high distribution rates.

VECC and OEB staff noted that InnPower’s customers are already paying among the highest distribution charges in the province. High customer rates are demonstrated by InnPower’s inclusion in the Fair Hydro Plan’s Distribution Rate Protection (DRP) program, which is applicable to only eight distributors in the province with the highest rates²⁰.

In reply submission, InnPower claimed that the parties’ submissions largely ignored cost drivers such as inflation, customer growth and spatial density. InnPower submitted the OEB should also consider exceptional annual OM&A costs, such as the Building cost of \$138,713, the increase in cable-locates of \$130,984, pension and benefit costs due to IFRS of \$60,500 and the OEB assessment cost increase of \$19,453.²¹

InnPower also indicated that OM&A costs attributable to InnServices had grown by more than inflation and customer growth, as InnPower was doing more work for its affiliate. InnPower indicated the OEB should consider these costs if the proposed OM&A budget is adjusted. As outlined in the evidence and in InnPower’s reply

²⁰ <https://www.ontario.ca/page/ontarios-fair-hydro-plan> - Lakeland Power Distribution Ltd. (Parry Sound), Atikokan Hydro Inc., InnPower Corporation, Chapleau Public Utilities Corporation, Sioux Lookout Hydro Inc., Northern Ontario Wires Inc., Algoma Power Inc., and Hydro One Networks Inc.

²¹ InnPower_ReplySUB_20171113, page 13

submission, the proposed 2017 OM&A budget includes expenses related to affiliate services.

InnPower indicated in undertaking J1.6, that revenues from providing Financial Services to its affiliate InnServices will be \$112,981 higher than the original forecast of \$232,198. However, InnPower stated that to remain consistent with the original application, this increase needs to be accomplished by a reduction in OM&A of \$112,981 as this change was not reflected in the forecast 2017 budget of \$5.990 million.

In addition, InnPower reiterated its need to fill three vacant positions as the work still needs to be done, and to address a variety of operational issues that have arisen due to the current understaffing situation. InnPower pointed to increased overtime, increased stress leaves, increased turnover, and the higher costs of subcontractor work, all of which lowers worker productivity and efficiency.

Findings

The OEB approves an OM&A budget of \$5.317 million for 2017, which represents a reduction of \$0.673 million from the \$5.990 million proposed by InnPower. The OEB finds that InnPower's proposed OM&A budget is too high compared to other electricity distributors. One reason for this conclusion is that InnPower incorrectly includes affiliate service expenses in its OM&A budget.

InnPower started the oral hearing with a summary of the staffing challenges it faces and also stated in the argument-in-chief that, "Existing staff are severely strained at current workloads".²² According to InnPower's witness, Ms. Cowles, from 2016 to 2017, union absenteeism increased by 109%, overtime increased by 59%, staff turnover was 19%, and there were seven stress leave occurrences.²³ Also InnPower noted that 50% of the CEO's time was reallocated to InnServices²⁴ and three positions remained unfilled.²⁵

Given these staffing challenges, InnPower would not appear to have excess operational capacity to leverage.

²² InnPower_ARGChief_20171006, page 4

²³ InnPower_hearing transcript_Volume 1 Public Redacted_20171003, page 13 & 14

²⁴ InnPower_hearing transcript_Volume 1 Public Redacted_20171003, page 68 & 69

²⁵ InnPower_ReplySUB_20171113, page 14

Nevertheless, InnPower and its shareholder decided to proceed with increasing the services provided to affiliates. InnPower is now a provider of Billing Services and Financial Services for InnServices, and is a lessor of rented space for a daycare. InnPower's statement that its staff are severely strained is difficult to reconcile with its willingness to take on more work for its affiliates and others.

The OEB's mandate is to set just and reasonable rates, taking into account the statutory objectives of protecting consumer interests and balancing the needs of the distributor, its customers and its shareholder(s). It is not incumbent (or appropriate) for this regulator, through increased electricity distribution rates, to address the cost pressures and staffing challenges faced by InnPower if they are due in part to the provision of services to its affiliate, InnServices.

The OEB finds it necessary to calculate a revised OM&A budget for the electricity distribution business only before it can assess the reasonableness of InnPower's proposal. InnPower's proposed OM&A budget is a mix of affiliate and distribution expenses, thereby inhibiting the analysis of the stand-alone regulated utility's OM&A costs and trends. All affiliate expenses related to InnServices should be properly allocated and reclassified in Account 4380 (see Revenues and Costs relating to Affiliate – InnServices section of this Decision).

Before taking into consideration any further reductions, the OEB calculates a revised 2017 OM&A budget of \$5,517,259 in Table 4, related to electricity distribution only, after eliminating expenses related to affiliate services, based on the evidence and InnPower's reply submission.

Table 4: 2017 OM&A budget related to electricity distribution

Source	Type of service provided	Cost of each service	OM&A budget 2017
OM&A budget proposed by InnPower			\$5,990,000
Cost included in \$5.990 million	Billing Services	(\$193,530)	
Overhead costs included in \$5.990 million	Billing Services	(\$125,240)	
Cost of \$232,198 already excluded from \$5.990 million ²⁶	Financial Services	No change	
Reduction from OM&A for additional costs ²⁷	Financial Services	(\$112,981)	
Overhead costs included in \$5.990 million	Financial Services	(\$40,990)	
Total budget expenses related to affiliate services eliminated from OM&A	Billing Service & Financial Services	(\$472,741)	(\$472,741)
OM&A budget revised related to electricity distribution only			\$5,517,259

Based on the calculations in Table 4, the OEB approves the reallocation of \$472,741 of affiliate service expenses from OM&A to Account 4380, as calculated by the OEB

²⁶ Undertaking J1.6 and InnPower's Reply Submission, paragraph 41

²⁷ Undertaking J1.6

above. The OEB also approves the inclusion of \$232,198 of Financial Services expenses in Account 4380. This amount had already been removed from OM&A by InnPower. A total of \$704,939 will be included in Account 4380 Expenses from Non Rate-Regulated Utility Operations for Billing and Financial Services.

The evidence indicates that InnPower's forecast for Account 4380 is \$983,861, which includes \$145,500 for "Miscellaneous Non-Utility Water"²⁸. The OEB cannot reconcile this amount with the \$193,530 of costs for Billing Services in undertaking J1.6. The OEB directs InnPower in its draft rate order to provide a summary of Account 4380, including the reclassifications required to reflect this Decision.

Based on the \$5,517,259 revised OM&A budget related to electricity distribution only, the OEB expects InnPower to find an additional \$200,000 in OM&A savings through efficiencies in its electricity distribution business. InnPower is poised to do so. It has a new CEO, a new management team, a growing customer base and a pending Business Plan. This is an opportunity for InnPower to assess and align its operating structure and processes to meet the needs of its future customers. The OEB approves an OM&A budget of \$5.317 million for 2017.

As a secondary check to assess the reasonableness of this OM&A budget of \$5.317 million, the OEB did an envelope analysis of the expected total increase from 2013 to 2017 using the following steps.

Step 1

The 2013 approved OM&A budget of \$4.890 million was adjusted to exclude Billing Service expenses of \$190,269²⁹ which were included in the approved budget.

Step 2

From 2013 to 2017, an adjustment of 10.2% was applied as follows:

- OEB's Price Cap IR inflation of 7.3%
- Pacific Economics Group Research, LLC (PEG) estimated increase due to customer growth of 4.1%
- InnPower's stretch factor of -1.2%

²⁸ Appendix 2-H Other Operating Revenue, September 20, 2017

²⁹ InnPower Reply Submission, p. 11

Step 3

The OM&A increase of \$138,713 related to the new Building, an amount referenced in the approved ICM settlement proposal was added.

The OEB did not find the other expenses identified by InnPower in its reply submission to be exceptional for inclusion in the analysis. The calculated 2017 OM&A budget is provided in Table 5.

Table 5: OM&A calculated increase from 2013 to 2017

Steps	Source	OM&A adjustments	OM&A
Step 1	2013 OEB-approved budget	\$4,890,000	
	Remove 2013 expenses related to affiliate for comparison purposes	(190,269)	\$4,699,731
Step 2	10.2% increase for inflation, customer growth minus stretch from 2013 to 2017	\$479,373	\$5,179,104
Step 3	Add annual expense increase related to the Building	\$138,713	\$5,317,817
Result	Expected OM&A increase in 2017 from 2013 OEB-approved (with affiliate expenses removed)	\$618,086	13%

In calculating a reasonable expected OM&A in 2017, the OEB did not use InnPower's customer growth rate of 9.4%. The OEB does not agree that OM&A costs should be driven in lockstep with customer growth rates. To do so would be inconsistent with the OEB's expectation that distributors find efficiencies and strive for continual

improvement. Accordingly, the OEB used the PEG adjustment of 0.44%³⁰ for every 1% of customer growth in this calculation. The resulting 2017 calculated OM&A budget of \$5,317,817 mirrors the approved budget of \$5.317 million.

Accordingly, for the reasons set out above, the OEB approves an OM&A budget of \$5.317 million for 2017 for rate-setting purposes.

3.9 Payments In Lieu of Taxes

InnPower initially requested 2017 Payments In Lieu of Taxes (PILs) of \$146,808 in its May 2017 amended filing, then updated its request to \$165,450 in the September 20, 2017 filing. This revision was made by updating the return on equity that is incorporated into taxable income and increasing capital cost allowance (CCA). No parties objected to the 2017 test year PILs of \$165,450.

Findings

The OEB directs InnPower to update its 2017 test year PILs provision to reflect the OEB's findings in this Decision.

3.10 Cost Allocation and Rate Design

InnPower submitted that its proposed cost allocation methodology, allocations and revenue-to-cost ratios are appropriate. InnPower also submitted that its proposals for rate design are appropriate.

With respect to the transition to fixed rates for Residential customers, InnPower proposed to extend its transition period from four to five years. All residential distribution rates currently include a fixed monthly charge and a variable usage charge. The OEB's residential rate design policy stipulates that distributors will transition residential

³⁰ Report of Pacific Economics Group Research, LLC, Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board, May 2013, Table 19, Customers Industry Average 2002-2011 of 0.44

customers to a fully fixed monthly distribution service charge over a four-year period, beginning in 2016³¹.

The OEB expects an applicant to apply two tests to evaluate whether mitigation of bill impacts for customers is required during the transition period. Mitigation usually takes the form of lengthening the transition period. The first test is to calculate the change in the monthly fixed charge, and to consider mitigation if it exceeds \$4. The second is to calculate the total bill impact of the proposals in the application for low volume residential customers (defined as those residential RPP customers whose consumption is at the 10th percentile for the class). Mitigation may be required if the bill impact related to the application exceeds 10% for these customers.

InnPower calculated a fixed charge increase of \$4.71 over a four-year period which exceeded the \$4 increase test established by the OEB. Over a five-year period the proposed increase would be \$3.53.

With respect to the GS > 50kW class, InnPower proposed to maintain the same fixed-variable split that informed the rate design in the previous cost-of-service settlement agreement³², updated to reflect 2016 approved rates, resulting in a fixed charge increase to \$229.34. InnPower submitted that this approach has been previously approved by the OEB.³³

VECC, SEC and OEB staff disagreed with the increase in the fixed charge for the GS > 50kW class.

VECC submitted that InnPower's proposed split did not reflect the current fixed-variable split or the split in the settlement agreement. VECC submitted that the fixed charge for the GS > 50kW class should be maintained at \$151.60 as it already lies beyond the upper boundary of OEB policy.

OEB staff also submitted that the existing fixed charge for the GS > 50kW class should be maintained at \$151.60. OEB staff indicated that the existing fixed charge was

³¹ OEB Policy – A New Distribution Rate Design for Residential Electricity Customers, EB-2012-0410, April 2, 2015

³² EB-2012-0139

³³ In page 32 of the reply submission, InnPower referred to the following cases: Horizon Utilities Corporations' 2015 rate decision (EB-2014-0002), as well as in EB-2012-0113, EB-2011-0293, EB-2011-0319, EB-2010-0131, EB-2010-0132 and EB-2010-0135.

already above the ceiling and should not be increased. SEC stated that the fixed charge for GS>50 should be set at the 2016 level, and not increased.

In its reply submission, InnPower argued that the parties' submissions regarding the GS>50kW fixed rate were based on a misreading of Section 2.8.1 of the Chapter 2 filing requirements and are not consistent with the OEB's practice as it relates to rate design, as set out in other OEB decisions.³⁴

InnPower indicated that if the OEB reduces the fixed rate for the GS>50kW class to \$151.60, this would reduce the fixed component of the fixed/variable split from 22.95% to 15.5%. InnPower stated that this change would be in the wrong direction, as the vast majority of distributor cost drivers are fixed, and such a move contradicts the OEB's general policy with regards to the fixed cost drivers.

Findings

The OEB approves InnPower's proposed cost allocation methodology. The OEB approves InnPower's rate design proposals with one exception.

With respect to the proposed five-year transition to fixed rates for the residential class, the OEB finds it unnecessary to extend InnPower's transition period beyond four years. Given the reductions in revenue requirement approved in this Decision, the OEB expects the resulting increase to the fixed charge to be close to \$4. The OEB prefers to adhere to the four-year transition period, as it was previously approved and aligns with the transition period for most electricity distributors in Ontario. InnPower is directed to update its rate calculation in the draft rate order to reflect three remaining years of transition.

With respect to the proposed GS >50kW fixed rate, the OEB approves InnPower's proposal to maintain the current fixed-variable split that results from 2016 approved rates. Maintaining the fixed-variable split results in an increase to the fixed charge which is consistent with the approach approved in past OEB decisions including the Horizon Utilities Corporation 2015 rate decision³⁵.

³⁴ On page 32 of its reply submission, InnPower referred to the following decisions: Horizon Utilities Corporations' 2015 rate decision (EB-2014-0002), as well as in EB-2012-0113, EB-2011-0293, EB-2011-0319, EB-2010-0131, EB-2010-0132 and EB-2010-0135.

³⁵ EB-2014-0002

3.11 Retail Transmission Service Rates & Low Voltage Rates

InnPower is fully embedded within Hydro One Networks Inc.'s (Hydro One's) distribution system. Hydro One is therefore the host distributor to InnPower. As a result, InnPower pays to Hydro One host-Retail Transmission Service Rates (RTSRs) charges for transmission services and low voltage service charges for distribution services. InnPower passes the cost of these services to its customers through its own RTSR and Low Voltage (LV) charges.

Neither VECC nor SEC made submissions with respect to the proposed RTSRs or LV rates. OEB staff did not make a submission on the LV rates. For the RTSRs, OEB staff submitted that the RTSRs, as updated, are acceptable, but should be updated if any new Uniform Transmission Rates (UTRs) are approved by the OEB. In its reply submission, InnPower agreed it was appropriate to update the RTSRs if new UTRs are approved.

Following the Technical Conference, InnPower filed an updated model that calculates proposed RTSRs based on the most recent host-RTSRs that have been approved for Hydro One, as shown in Table 6.

Table 6: Hydro One Networks Inc. Sub-Transmission Host-RTSRs³⁶

Current Applicable Sub-Transmission Host-RTSRs (2017)	per kWh
Network Service Rate	\$3.1942
<u>Connection Service Rates</u>	
Line Connection Service Rate	\$0.7710
Transformation Connection Service Rate	\$1.7493

OEB staff submitted that the updated RTSR model was acceptable.

Findings

InnPower's proposed RTSRs filed following the Technical Conference are approved. These RTSRs were adjusted to reflect the current host-RTSRs charged by Hydro One.

³⁶ Decision and Order, EB-2016-0081, December 21, 2016

While new UTRs have been approved by the OEB, InnPower is fully embedded within Hydro One's distribution system and new host-RTSRs have not yet been approved for 2018.

Cost differences resulting from the approval of new host-RTSRs from Hydro One will be captured in Accounts 1584 and 1586 for future disposition.

The LV charges proposed by InnPower are approved. InnPower used an average of costs over four years (2012 to 2015) and adjusted for projected load growth. Cost differences resulting from the approval of new LV charges from Hydro One will be recorded in Account 1550 for future disposition.

The OEB notes that InnPower accumulated a debit balance in Account 1550 in both 2015 and 2016. This means that InnPower has been collecting less from customers for LV charges than it has paid to Hydro One. If this trend continues, InnPower should propose an update to its LV rates as part of a future IRM application, rather than waiting to adjust the rates in its next cost of service rate application.

3.12 Deferral and Variance Accounts

Variance accounts track the difference between the forecast cost of a project or program, which has been included in rates, and the actual cost. If the actual cost is lower, then the over-collected money is refunded to customers. If the actual amount is higher, then the utility can request permission to recover the under-collected amount through future rates. A deferral account tracks the cost of a project or program which the utility could not forecast when the rates were set. When the costs are known, the utility can then request permission to recover the costs in future rates.

InnPower is seeking disposition of its deferral and variance accounts (DVAs) as at December 31, 2015, with interest projected to December 31, 2016. During the oral hearing, OEB staff questioned InnPower's approach to allocating costs between regulated price plan (RPP) and non-RPP customers and the resulting balances in Account 1588 RSVA Power and Account 1589 RSVA Global Adjustment.

In its response to undertaking J1.8, InnPower withdrew its request to dispose of Accounts 1588 and 1589. InnPower proposed to perform a reconciliation and true up of the allocation of the Global Adjustment charges and to adjust Accounts 1588 and 1589. InnPower stated that it would request disposition of Accounts 1588 and 1589 at its next IRM rate application. InnPower also withdrew its request for disposition of \$26,651 in

Account 1568 Lost Revenue Adjustment Mechanism Variance Account, as well as the removal of certain Z-factor amounts recorded in Account 1572 Extraordinary Event Costs of approximately \$296k. With its Argument-in-Chief, InnPower filed an updated continuity schedule for its DVAs. This included Group 1 and Group 2 balances, excluding Accounts 1568, 1572, 1588 and 1589. VECC and OEB staff both found InnPower's proposal acceptable.

OEB staff submitted that InnPower should provide a report of its analysis and adjustments made to Accounts 1588 and 1589. OEB staff was of the view that a Special Purpose Audit of InnPower's Account 1588 and Account 1589 should be conducted. VECC qualified its acceptance by saying that InnPower should address and resolve the discrepancies and clarifications raised by OEB staff.

Findings

The OEB approves the disposition of the Group 1 balances as of December 31, 2015 with interest projected to December 31, 2017, with the exception of Accounts 1568, 1572, 1588 and 1589. The approved balances with interest projected to December 31, 2016 are provided in Table 7, and are based on the continuity schedule filed by InnPower as part of its Argument-in-Chief. As part of the draft rate order process, InnPower is expected to update balances for interest projected up to the effective date of the disposition rate riders, December 31, 2017.

Table 7 – Approved DVA balances with interest to December 31, 2016³⁷

Group 1	Account No.	December 31, 2015 balances with interest projected to December 31, 2016
LV Variance Account	1550	307,729
Smart Metering Entity Charge Variance Account	1551	(5,532)
RSVA - Wholesale Market Service Charge	1580	(535,257)
RSVA - Retail Transmission Network Charge	1584	94,572
RSVA - Retail Transmission Connection Charge	1586	188,124
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(352)
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	6,711
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	104
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	(13,803)
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	203,730
Total of Group 1 Accounts Approved for Disposition		246,026

Group 2	Account No.	December 31, 2015 balances with interest projected to December 31, 2016
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	11,929
Other Regulatory Assets - Sub-Account - Other	1508	2,565
Retail Cost Variance Account – Retail	1518	61,171
Retail Cost Variance Account – STR	1548	26,247
Total of Group 2 Accounts Approved for Disposition		101,912

While it is generally preferable to dispose of all Group 1 balances together, it is most important that balances are accurate. Therefore the OEB accepts InnPower's proposal to withdraw its request to dispose of the balances in Accounts 1588 and 1589 pending its review of these accounts. It is also important that balances are disposed on a timely basis. The OEB will therefore permit the other Group 1 balances to be disposed now since they are 2015 balances and it is now 2018.

The OEB policy is to only dispose of Group 2 accounts in a cost of service application. It is therefore appropriate to dispose of these balances in this proceeding.

³⁷ Final balances will include interest to December 31, 2017

InnPower confirmed in its response to interrogatory 9.0-Staff-59 that it is foregoing its recovery of the Account 1568 balance accumulated to December 31, 2015 and the Z-factor amount recorded in Account 1572, not just deferring recovery. InnPower is expected to record balances in Account 1568 from January 1, 2016 onwards for future consideration.

The OEB approves two new variance accounts to start effective January 1, 2018, as discussed in the Revenues and Costs Relating to Affiliate – InnServices section in this Decision, as follows.

- Account 1508 –Other Regulatory Assets, Sub-account Difference in Revenues from Affiliate Services
- Account 1508 – Other Regulatory Assets, Sub-account Difference in Expenses from Affiliate Services

The OEB directs InnPower to include draft accounting orders for these two new accounts in its draft rate order.

3.13 Rate Riders

InnPower had three rate riders approved in its ICM Application³⁸ with expiry dates of December 31, 2016:

- Rate Rider for Recovery of Incremental Capital - fixed charge
- Rate Rider for Recovery of Incremental Capital - volumetric charge
- Rate Rider for Disposition of Capital Gains

InnPower also had two rate riders approved in its 2016 Price Cap IR application³⁹ with expiry dates of December 31, 2016:

- Rate Rider for Disposition of Deferral/Variance Accounts (2016)
- Rate Rider for Disposition of Global Adjustment Account (2016)

InnPower indicated that it has continued to collect the ICM rate rider through 2017 consistent with the terms of the rate order declaring its rates interim effective January 1,

³⁸ EB-2014-0086

³⁹ EB-2015-0081

2017. InnPower proposed that a final reconciliation of these rate riders be included with its next Price Cap IR application.

OEB staff submitted that the rate rider reconciliation should be completed as part of this proceeding.

OEB staff noted that as the new rates will reflect the new Building in rate base for the first time, InnPower should show detailed calculations in its draft rate order. OEB staff submitted that if any amounts have been over recovered, InnPower should propose a rate rider to refund amounts to customers. OEB staff indicated that if InnPower prefers the balances to be audited as part of its annual financial statement audit, any refunds may be deferred to a future Price Cap IR proceeding.

Findings

The OEB finds that InnPower incorrectly continued to charge these rate riders after the approved expiry dates. The rate order declaring rates interim should not override a pre-approved rate rider expiry date. In addition, rates were declared interim the day after the expiry dates for the rate riders.

In a letter dated January 9, 2018 (letter), the OEB indicated that it expected InnPower to end three of the rate riders which continued in 2017, effective December 31, 2017. InnPower confirmed it ended the rate riders effective December 31, 2017. In particular:

- Rate Rider for Disposition of Capital Gains
- Rate Rider for Disposition of Deferral/Variance Accounts (2016)
- Rate Rider for Disposition of Global Adjustment Account (2016)

In the letter, the OEB explained that as these rate riders were established to dispose of specific approved account balances, and money was either over collected or over refunded to customers. To address this issue, the OEB directs InnPower to transfer any over refunded balances with respect to capital gains to a sub account in Account 1595 for future disposition. To the extent there has been an over or under collection of the 2016 DVA and 2016 Global Adjustment balances, the residual balances in Account 1595 can be addressed in a subsequent application.

The remaining two rate riders that continued past December 31, 2016 related to incremental capital approved in the ICM proceeding. These rate riders provided rate relief to InnPower until its rates were rebased. In this application, InnPower proposes to

add the related assets to rate base and earn a return through base rates in the revenue requirement calculation.

The OEB directs InnPower to use the net book value of the associated net ICM assets on the effective date of this Decision as the addition to rate base.

On the effective date, the incremental capital rate riders should have been displaced by the return provided through the new base rates. To the extent that the rate riders continued to be charged after the effective date, this amount should be considered in the forgone revenue calculation.

The OEB does not find it necessary to true-up the ICM rate riders. A true up would reconcile any difference between the actual and expected revenue collected through the incremental capital rate riders. A true-up was not proposed by InnPower and there is no evidence to indicate the difference would be material.

3.14 Other Operating Revenue

Specific Service Charges

InnPower proposed to increase four of its specific charges included in other operating revenue. InnPower described these charges in its Argument-in-Chief as follows:

- (a) An increase in the “Disconnect/reconnect charge – at meter- during regular hours” charge from \$40 to \$65 to better reflect current contractor average costs for disconnects/reconnects.
- (b) An increase in the “Temporary Service – Install & Removal – Underground – No Transformer” charge from \$300 to \$468, to better reflect actual costs associated with both the install and removal portions of the activity.
- (c) An increase in the “Temporary Service – Install & Remove – Overhead – No Transformer” charge from \$500 to \$632, to better reflect the actual costs associated with both the installation and removal activities.
- (d) An increase in the “Temporary Service – Install & Remove – Overhead – With Transformer” charge from \$1000 to \$2525, to better reflect the actual costs associated with both installation and removal activities.

OEB staff had no issues with the proposed changes to the specific service charges.

Findings

The OEB approves the increase in the Disconnect/Reconnect charge from \$40 to \$65. Consistent with the Distribution System Code (DSC), this charge should only apply upon the reconnection of a service that has been disconnected. In approving the increase, the OEB notes that most distributors have a Disconnect/Reconnect charge of \$65, as this was the generic charge set by the OEB within the *2006 Electricity Distribution Rate Handbook* (2006 Handbook). InnPower will therefore have a charge consistent with most other distributors.

The OEB approves the increase to the three charges for Temporary Services. The OEB has previously approved Temporary Service charges for Hydro Ottawa⁴⁰ and Toronto Hydro⁴¹ that exceed the new charges proposed by InnPower.

MicroFIT Charge

In its application, InnPower proposed to change its microFIT charge from \$5.40 to \$10 but later withdrew this request. In its Decision and Procedural Order No. 7 issued on November 10, 2017, the OEB agreed to retain the charge at \$5.40, which is the provincial-wide charge calculated by the OEB.

Findings

The microFIT charge is approved on a final basis to remain at \$5.40 per month.

Pole Attachment Charge

InnPower also sought to withdraw its request to increase its pole attachment charge from the current charge of \$22.35 per pole per year. The OEB denied this request in its Decision and Procedural Order No. 7, and established separate procedural steps regarding the pole attachment charge.

The OEB has initiated a generic policy review of pole attachment charges that is considering the methodology to be used for determining pole attachment charges. The OEB's current methodology was established in a 2005 decision in the RP-2003-0249

⁴⁰ EB-2016-0084

⁴¹ EB-2014-0116

proceeding (2005 Decision). At the time of Procedural Order No. 7, the OEB had not established any new policy direction and the OEB stated that it would be guided by the 2005 Decision until any new methodology is determined. InnPower was ordered to file new evidence based on the current methodology.

On December 18, 2017, the OEB issued a draft Report of the Board Framework for Determining Wireline Pole Attachment Charges⁴². This described a new methodology for determining pole attachment charges (Draft New Methodology). The OEB has not issued a final report at this time.

InnPower reached an agreement with the intervenors on the pole attachment charge and filed a settlement proposal with the OEB for its consideration (pole attachment settlement proposal). The parties agreed to a pole attachment charge of \$38.82, not including a charge for vegetation management. Parties also agreed that the forecasted revenue from the charge would be \$269,217.

The parties to the pole attachment settlement proposal agreed to use the current methodology from the 2005 Decision⁴³ in the calculation of the new rate. There is an existing joint-use agreement between Rogers and InnPower that allows InnPower to charge an amount for vegetation management. InnPower and Rogers have agreed “to meet and discuss an appropriate approach to facilitate InnPower to begin charging for the provision of vegetation management services pursuant to the terms of the existing joint-use agreement going forward”. The pole attachment settlement proposal makes provision for a deferral account to record “revenues received by InnPower prior to its next cost of service application for the provision of vegetation management services”.

OEB staff raised a number of concerns about the accuracy of costs and data used in the calculation of the rate in the pole attachment settlement proposal. OEB staff recommended that the OEB not accept the pole attachment settlement proposal.

The parties filed a joint reply and argued that the costs for a smaller distributors like InnPower might reasonably be expected to differ from the costs of larger distributors that were used in the calculation of the rate using the Draft New Methodology.

⁴² EB-2015-0305

⁴³ As modified in the EB-2015-0004 proceeding for Hydro Ottawa and the EB-2015-0141 proceeding for Hydro One

Findings

The OEB accepts the pole attachment settlement proposal (Schedule A). It does so with the expectation that InnPower and Rogers will reach an agreement on a charge for vegetation management under the terms of the joint-use agreement. InnPower is expected to adhere to any requirements that the OEB may establish for the tracking of costs related to pole attachments, including the setup of new sub-accounts.

The OEB has not yet finalized a new policy with respect to pole attachments, and evidence was filed in this proceeding using the methodology from the 2005 Decision, as ordered by the OEB. Given this unique circumstance of timing, the OEB accepts the methodology adopted by the parties to calculate a new charge. The OEB's acceptance of this pole attachment settlement proposal should not be understood as approving this methodology for use by InnPower in its next rebasing application.

In accepting this pole attachment settlement proposal, the OEB notes that the forecast revenue resulting from the new charge is \$269,217, which is a 67% increase from the actual revenue of \$161,207 received from pole attachments in 2015. Furthermore, the difference between the \$269,217 in forecast revenue resulting from the pole attachment settlement proposal and the revenue that would result from using the charge from the Draft New Methodology (with the component for vegetation management removed for comparison purposes) would not exceed InnPower's materiality threshold, calculated to be \$61,927 in the application.

It is unclear the extent to which any data issues exist. The OEB expects that there will be requirements resulting from the OEB's policy review for InnPower to track costs going forward. This will ensure that any data issues are resolved for the next time that InnPower rebases.

InnPower shall file a draft accounting order as part of the rate order process for the deferral account for revenue from vegetation management services, consistent with the terms within the pole attachment settlement proposal.

Other Income

As outlined in the evidence and in InnPower's reply submission, the proposed 2017 other operating revenue budget includes revenues related to affiliate services. Findings with respect to the costs and revenue for affiliate services are elsewhere in this Decision.

Findings

The OEB approves the remaining items of revenue forecast by InnPower and itemized in Appendix 2-H.

The OEB directs InnPower to include \$33,000 in Rent from Electric Property in other operating revenue for the rent related to the leased portion of the Building in 2017, as discussed in the Rate Base - Corporate Headquarters and Operations Centre section earlier in this Decision. The expected rent for the remaining four months of 2017 is \$33,000.

InnPower should also update Appendix 2-H to reflect the OEB findings in the Revenues and Costs relating to Affiliate – InnServices section of this Decision.

3.15 InnPower's Collection Process

At the community meetings held by the OEB on March 9, 2017, and through letters of comment from customers, concerns were raised about InnPower's collections process, particularly disconnection procedures. In the OEB staff Summary of Community Meeting report issued on May 2, 2017, OEB staff reported that: "Several participants described their experiences with InnPower's disconnection procedures, which they found to be unduly aggressive. Several comments also indicated dissatisfaction with customer service."

VECC reiterated these concerns and stated that it was concerned with InnPower's practices around disconnection notices, electricity shut-downs, late payments, and the associated fees. VECC described InnPower's late payment and collection policy as "harsh and restrictive" and submitted that the OEB should require InnPower to allow customers to carry a minimum of one month's balance (with late payment interest applying).

Findings

The OEB directs InnPower to undertake a review of its collections process including the timing and nature of notices, taking into consideration the feedback from its customers. The OEB also requires InnPower to document this process in its Conditions of Service.

The OEB is concerned that InnPower has not provided descriptions of its miscellaneous charges either in its evidence or in its Conditions of Service. InnPower may be relying on the 2006 Handbook for its description of charges, because at the oral hearing

InnPower referred to its use of a “standard charge” from the “rate application process handbook”. The 2006 Handbook was established for the setting of 2006 rates and should not be relied upon as OEB policy. However, given that InnPower has provided no other description for its specific service charges, InnPower’s Tariff of Rates and Charges will need to be based on the descriptions from the 2006 Handbook until it next rebases, or until the OEB issues new guidance with respect specific service charges.

Both InnPower’s customers and VECC raised concerns about InnPower’s collections process. InnPower responded that its practices are in strict compliance with the OEB’s DSC.

The OEB will not comment on InnPower’s compliance with the DSC, other than to note that InnPower’s Conditions of Service does not include the business process it uses to disconnect and reconnect consumers, as is required by the DSC.

On its current Tariff of Rates and Charges, InnPower has a \$15 charge for “Collection of account charge - no disconnection”. However, during the oral hearing, InnPower explained that the \$15 charge was for the delivery of a disconnection notice. The OEB questions if there is an inconsistency between the tariff sheet description and the application of the fee.

The goal of the customer visit should be to collect payment on an account, or to arrange payments, so that a disconnection is not required. InnPower must reflect on its objective and terminology as it conducts its collection process review.

The OEB is conducting its own review of distributors’ customer service policies⁴⁴. The first phase of that review is examining:

- Disconnection for non-payment
- Billing and payments
- Arrears management programs
- Security deposits including criteria for waiver and refund
- Service charges relating to nonpayment of accounts

InnPower will need to take into consideration any new OEB customer service policies as it reviews its collections process.

⁴⁴ EB-2017-0183

3.16 Effective Date

InnPower proposed an effective date of July 1, 2017 for its new rates. InnPower submitted that given the Government of Ontario's announcement of a 25% Fair Hydro Plan reduction of electricity bills was made one week before InnPower's Community Day, there was confusion among customers about the relationship between InnPower's rate application and the government announcement.⁴⁵ InnPower submitted that many customers were upset at the Community Day, which was beyond management's control. In response to the feedback from customers, InnPower amended its application in May 2017 on issues applicable to the rate application which were within InnPower's control.⁴⁶

Both VECC and OEB staff noted OEB decisions approving an effective date of the first of the month following issuance of the decision. Both parties declined to urge that the OEB follow this precedent in the event of a significant reduction to InnPower's OM&A, proposing an effective date of October 1, 2017 instead.

SEC argued that the effective date should be the first of the month following the rate order. SEC submitted that the customers of InnPower are already faced with a substantial rate increase and an additional rider to recover the retroactive component of that rate increase would be a further burden to customers already paying high rates.

Findings

The OEB approves an effective date of January 1, 2018 for InnPower's new rates. The OEB finds many of the delays in this proceeding were within the control of InnPower's management. The OEB finds that the timing of the Fair Hydro Plan's announcement was coincidental, yet InnPower's customers had many other issues with existing distribution rates and services, as expressed to the OEB at the Community Day and through letters of comment.

The OEB finds January 1, 2018 to be appropriate as its approvals are based on a full year of expenses, revenues and rate base. The OEB also finds merit in establishing new rates at the start of InnPower's fiscal year given that the net book value of the Building is added to rate base. The capital gains rate rider and DVA rate riders also

⁴⁵InnPower_ReplySUB_20171113, page 36-37

⁴⁶ InnPower_EB-2016-0085_Amended Application_20170508, page 3

ended on December 31, 2017. The OEB notes that January 1, 2018 is two months after InnPower's reply submission was filed on November 13, 2017. InnPower's reply submission included new information and rate making proposals that the OEB considered in its Decision.

The forgone revenue resulting from an implementation date for the approved new rates subsequent to the effective date of January 1, 2018, will be addressed through the draft rate order process as explained in the Implementation section of this Decision.

4 IMPLEMENTATION

The OEB directs InnPower to incorporate the cost consequences of the findings in this Decision in its revenue requirement calculations for 2017 in its draft rate order.

The OEB expects InnPower to file detailed supporting material showing the impact of this Decision on the overall revenue requirement, the allocation of revenue requirement to its rate classes, the derivation of base rates, the determination of the final rates and rate riders, including bill impacts.

InnPower's draft rate order should include a revised Tariff of Rates and charges reflecting this Decision, and including updates to the RRRP charge, loss factors, DVA rate riders, etc.). In addition, the Smart Metering Entity Charge was set at \$0.57 by the OEB, effective January 1, 2018 to December 31, 2022⁴⁷. The Tariff of Rates and Charges should be adjusted to incorporate this rate.

InnPower's draft rate order should also include draft accounting orders for the three new variance accounts approved in this Decision.

The implementation date for new rates will be subsequent to January 1, 2018. For the recovery of forgone revenue, the OEB will approve forgone revenue rate riders to be collected from customers from the implementation date to December 31, 2018. InnPower is required to submit a proposal for the calculation of the forgone revenue rate riders as part of the draft rate order process.

As InnPower is included in the Fair Hydro Plan's DRP program, the rates charged to InnPower's customers will be lower than the rates approved in the final rate order in this proceeding.

SEC and VECC are eligible for cost awards in this proceeding. The OEB will make provision for these intervenors to file their cost claims in its final rate order.

⁴⁷ Decision and Order, EB-2017-0290, March 1, 2018

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. InnPower Corporation shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision, within **14 days** of the date of this Decision and Order. InnPower Corporation shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.
2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to InnPower Corporation within **7 days** of the date of filing of the draft rate order. The OEB intends to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order.
3. InnPower Corporation shall file with the OEB and forward to intervenors, responses to any comments on its draft rate order within **7 days** of the date of receipt of the comments.

All filings to the OEB must quote the file number, EB-2016-0085, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at <https://pes.ontarioenergyboard.ca/eservice/>. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at <http://www.oeb.ca/Industry>. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Fiona O'Connell at fiona.oconnell@oeb.ca and OEB Counsel, Ljuba Djurdjevic at ljuba.djurdjevic@oeb.ca.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

E-mail: Boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto March 8, 2018

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

SETTLEMENT PROPOSAL

(WIRELINE POLE ATTACHMENT RATE)

DECISION AND ORDER

INNPOWER CORPORATION

EB-2016-0085

MARCH 8, 2018

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

EB-2016-0085

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by InnPower Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective July 1, 2017.

INNPOWER CORPORATION

SETTLEMENT PROPOSAL
(Wireline Pole Attachment Rate)

FEBRUARY 2, 2018

TABLE OF CONTENTS

APPENDICES 4

LIVE EXCEL MODEL 4

SETTLEMENT PROPOSAL (WIRELINE POLE ATTACHMENT RATE) 5

SUMMARY 8

DETAILED SETTLEMENT 9

 1. What is the appropriate methodology to establish the pole attachment rate?..... 9

 2. What is the appropriate pole attachment rate?..... 10

APPENDIX “A” COMPARISON TO THE DRAFT METHODOLOGY 13

 No. of Attachers per Pole 13

 Vegetation Management 14

 Allocation of Direct Costs (Administration and LIP Costs) 15

 Allocation Methodology 16

 Indirect Costs 17

 Power Deduction Factor..... 18

 Inflation 18

APPENDIX “B” UPDATES TO THE EVIDENCE 20

 A: Administration Costs Per Pole 20

 B. Loss in Productivity..... 20

 C. Pole Maintenance Expense..... 21

 D. Capital Carrying Costs 21

 E. The Allocation Factor 22

APPENDIX “C” APPENDIX 2-H OTHER OPERATING REVENUE..... 23

**APPENDIX “D” EXCERPT FROM POLE ATTACHMENT AGREEMENT BETWEEN
INNISFIL HYDRO DISTRIBUTION SYSTEMS LTD., (NOW INNPOWER
CORPORATION) AND ROGERS CABLE COMMUNICATIONS INC 24**

APPENDICES

The following Appendices are attached to and form an integral part of this Settlement Proposal:

Appendix “A” – Comparison to the Draft Methodology

Appendix “B” – Updates to the Evidence

Appendix “C” – Other Operating Revenue

Appendix “D” – Excerpt from Pole Attachment Agreement

LIVE EXCEL MODEL

In addition to the Appendices listed above, the following live excel model has been filed together with and form an integral part of this Settlement Proposal:

- InnPower_Pole_Attachment_Settlement_20180131.xlsx
(hereinafter referred to as the “**Settlement Model**”)

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

InnPower Corporation
EB-2016-0085
Settlement Proposal
(Wireline Pole Attachment Rate)

Filed with OEB: February 2, 2018

InnPower Corporation (“**InnPower**”) filed an amended cost of service application with the Ontario Energy Board (the “**OEB**”) on May 11, 2017 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the “**Act**”), seeking approval for changes to the rates that InnPower charges for electricity distribution and other charges to be effective July 1, 2017 (OEB Docket Number EB-2016-0085) (the “**Application**”).

The OEB issued and published a Notice of Hearing on February 22, 2017, pursuant to which the School Energy Coalition (“**SEC**”) and the Vulnerable Energy Consumers Coalition (“**VECC**”) applied for and were approved as intervenors.

The OEB issued Procedural Order No. 1 on May 16, 2017, and on May 26, 2017, the OEB issued Procedural Order No. 2 which required InnPower to provide notice of the application to three specific customer groups that would be directly impacted by one or more of the proposed changes to specific service charges, including pole attachment rates, microFIT charges and net metering charges as well as providing for further interrogatories and responses.

On September 15, 2017, InnPower submitted an affidavit of publication and service in accordance with Procedural Order No. 2. On September 27, 2017, Rogers Communications Canada Inc. (“**Rogers**”) filed an intervention request, which request was approved by the OEB in its Decision on Confidentiality and Intervention Request dated October 2, 2017.

Previously, on August 23, 2017, InnPower had filed a letter with the OEB requesting that InnPower be permitted to withdraw its request to increase rates for two of the customer groups (pole attachment customers and microFIT customers) and confirming that it had no customers in the third group (net metering customers). InnPower indicated that it would prefer to await the outcome of the Pole Attachment Working Group (“**PAWG**”) in EB-2015-0304 prior to determining a new pole attachment charge.

On October 10, 2017, the OEB published Procedural Order No. 6 referencing the ongoing work of the PAWG and, in light of which, parties were invited to make submissions on the question of whether or not the OEB should consider a change to InnPower’s pole attachment and microFIT rates.

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

InnPower's request to withdraw a change to its pole attachment charge was contested by SEC,¹ VECC,² and Rogers.³ OEB staff argued that the OEB should not consider changes to the pole attachment charge, stating that “[g]iven the ongoing policy review, OEB staff is concerned that embarking on a review of InnPower's pole attachment charge could result in duplication of effort and complicate this application in a manner that is disproportionate to any ultimate impact on ratepayers.”⁴

In Procedural Order No. 7, issued on November 10, 2017, the OEB determined that it would consider a change to the current pole attachment charge of \$22.35 but would not consider a change to the microFIT charge of \$5.40.

Consistent with Procedural Order No. 7, InnPower filed updated evidence with respect to pole attachment charge on November 28, 2017, and interrogatory responses on December 18, 2017.

In accordance with Procedural Order No. 7, a settlement conference was convened on January 8th and 9th 2018 in accordance with the OEB's *Rules of Practice and Procedure* (the “**Rules**”) and the OEB's *Practice Direction on Settlement Conferences* (the “**Practice Direction**”).

Marie Rounding acted as facilitator for the settlement conference which lasted for two days.

InnPower and the following intervenors (the “**Intervenors**”), participated in the settlement conference:

SEC;
VECC; and
Rogers.

InnPower and the Intervenors are collectively referred to herein as the “**Parties**”.

OEB staff also participated in the settlement conference. The role adopted by OEB staff is set out in page 5 of the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who did participate in the settlement conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

This document is called a “Settlement Proposal” because it is a proposal by the Parties to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this agreement is subject to a condition subsequent, that if it is not accepted by the

¹ By letter dated August 24, 2017.

² <http://www.rds.oeb.ca/HPECMWebDrawer/Record/589278/File/document>

³ <http://www.rds.oeb.ca/HPECMWebDrawer/Record/589290/File/document>

⁴ <http://www.rds.oeb.ca/HPECMWebDrawer/Record/589009/File/document>

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

OEB in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this agreement, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that this settlement proceeding is confidential in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this settlement conference, and in this Agreement, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the settlement conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the settlement conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not physically in attendance at the settlement conference but were a) any persons or entities that the Parties engage to assist them with the settlement conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

This Settlement Proposal provides a brief description of each of the settled and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, and (b) the Appendices to this document. The supporting Parties for each settled and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by InnPower. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

In the tables, figures shall be deemed to be in dollars, unless otherwise characterized (i.e. kW, %, etc.).

Outlined below are the final positions of the Parties following the settlement conference.

SUMMARY

The Parties are pleased to advise the OEB that they have reached a complete agreement with respect to the appropriate pole attachment rate for InnPower.

On December 18, 2017, the same day that InnPower filed its pole attachment interrogatory responses, the OEB released a Draft Report titled “Framework for Determining Wireline Pole Attachment Charges”, OEB File No. EB-2015-0304 (the “**Draft Methodology**”) along with a supporting expert report from Nordicity. The OEB invited comments from stakeholders on the Draft Methodology. The deadline to file comments has been extended several times. Comments are currently due Feb. 9, 2018.

The Draft Methodology differs in a number of respects from the methodology approved by the OEB in the “**CCTA Decision**”,⁵ the “**Hydro Ottawa Decision**”,⁶ and the “**Hydro One Decision**”⁷ (collectively referred to herein as the “**CCTA Methodology**”).

As a consequence the Parties to the settlement have addressed two key issues:

1. *What is the appropriate methodology to establish the pole attachment rate?*
2. *What is the appropriate pole attachment rate?*

The settlement of these two issues are addressed below.

According to the Practice Direction (p. 3), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. The Parties agree that no such adjustments are required for this Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the OEB does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the OEB does accept may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties

⁵ Decision and Order dated March 7, 2005 (OEB File No. RP-2003-0249).

⁶ Decision and Rate Order on Pole Attachment Charge for Hydro Ottawa, dated February 25, 2016 file number EB-2015-0004 (“**Hydro Ottawa**”)

⁷ Decision and Rate Order on a Motion to Review and Vary dated August 4, 2016 (OEB File No. EB-2015-0141) (the “**Hydro One Decision**”)

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

who took on a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the OEB.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not InnPower is a party to such proceeding. For greater certainty, the adoption or use of any methodology or calculation in this Settlement Proposal reflects the Parties' agreement to adopt such methodologies or calculations solely for the purpose of this Settlement Proposal, and should not be construed as the Parties' general acceptance of any one or more of such methodologies or calculations in current or future proceedings before the Board. Moreover, the Parties take no position in this proceeding on the Draft Methodology and this settlement is without prejudice to the rights of the Parties to take any position in respect of such policy consultation and any future proceeding before the Board.

Where in this Agreement, the Parties "Accept" the evidence of InnPower, or the Parties or any of them "agree" to a revised term or condition, including a revised budget or forecast, then unless the Agreement expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

DETAILED SETTLEMENT

1. What is the appropriate methodology to establish the pole attachment rate?

Complete Settlement: The Parties agree InnPower's 2017 pole attachment rate shall be established based on the CCTA Methodology.

Parties in Agreement: All

Parties Opposed: None

Evidence: None

Rationale:

Use of the CCTA Methodology is consistent with the instructions of OEB in Procedural Order No. 7, which states (**emphasis added**):

"As referenced in InnPower's letter of August 23, 2017, the OEB has initiated a generic policy review of pole attachment charges. This review is considering the methodology to be used for determining pole attachment charges. In Procedural Order No. 6, the OEB indicated that the expected issuance date of a new policy on pole attachment charges is unknown. **Until any new methodology is determined, the OEB is guided by its 2005 Decision.**"

and

“InnPower’s evidence should be based on the current methodology for determining pole attachment charges as set out in the 2005 Decision. Consistent with the Hydro Ottawa Decision on pole attachments, the evidence must include InnPower’s number of attachers per pole, and distinguish between direct and indirect costs.”

No new methodology has yet been determined. The Draft Methodology is a draft that has been published for stakeholder comment only. The final methodology, if any, adopted by the OEB could change from the Draft Methodology based on the comments received and the decisions of the OEB following the consultation.

The use of the Draft Methodology as a basis for settlement could result in the Parties adopting an approach that differs from both the CCTA Methodology and from the final methodology, if any, approved by the OEB following the conclusion of its public consultation process. The Parties’ agree that this would not be in the public interest.

However, for the benefit of the OEB panel, InnPower has included in Appendix “A” to this Settlement Proposal a summary of the key differences between the CCTA Methodology used for the purposes of this Settlement Proposal and the methodology proposed in the Draft Methodology.

For the reasons more fully detailed in Appendix “A”, the Parties agree that the CCTA Methodology more appropriately reflects the particular costs and facts and circumstances of InnPower for the purposes of calculating an appropriate pole attachment rate.

2. *What is the appropriate pole attachment rate?*

Complete Settlement: The Parties agree that the appropriate InnPower specific pole attachment rate is \$38.82 per pole per year.

In addition, the Parties agree that the forecasted revenue in Account 4210 in the test year should be \$269,217 to reflect the incremental revenue associated with this change in the pole attachment rate over a 12 month period.

The calculation of this pole attachment rate is shown in the attached excel Settlement Model.

Rogers and InnPower have agreed, as part of this Settlement Proposal, to meet and discuss an appropriate approach to facilitate InnPower to begin charging for the provision of vegetation management services pursuant to the terms of the existing joint-use agreement going forward. InnPower and Rogers will use commercially reasonable efforts to reach agreement in a timely manner. Disputes will be governed by the terms of the applicable joint-use agreement.

To ensure consistent treatment among all wireline attachers with attachments in the communications space, InnPower agrees to charge other such attachers for vegetation

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

management services on the same basis as it charges Rogers if permitted pursuant to the terms of the applicable joint-use agreement.

Since no revenues are forecasted in rates in 2017 from vegetation management:

The Parties agree that the OEB should also approve the creation of a new non-interest bearing deferral account, called the “*Vegetation Management Revenues on Joint-Use Poles Deferral Account*”, which would be used to record any revenues received by InnPower prior to its next cost of service application for the provision of vegetation management services pursuant to the terms of any joint-use agreement for wireline communications attachments. InnPower would dispose of this account to the benefit of ratepayers as part of its next cost of service application.

The evidence in the Settlement Model reflects updates and factual corrections to the evidence found in “InnPower_APPL_Pole Attachment_20171218.xlsx” filed as part of InnPower’s IR responses (“**IR Spreadsheet**”).

The updates and corrections that arose during the course of settlement discussions are more fully explained in Appendix “B” to this Settlement Proposal.

Parties in Agreement: All

Parties Opposed: None

Evidence References:

InnPower_APPL_Pole Attachment_20171127.pdf

InnPower_APPL_Pole Attachment_20171127.xlsx

InnPower_IRR_PO7_20171218.pdf

InnPower_APPL_Pole Attachment_20171218.xlsx

InnPower_Pole_Attachment_Settlement_20180131.xlsx

Appendix “B”

Appendix “C”

Rationale:

- The Parties agree that, given the evidence before them, a pole attachment rate of \$38.82 per pole per year is a fair and reasonable allocation of InnPower’s actual costs to the wireline pole attachers.

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

- The pole attachment rate of \$38.82 per pole per year is based upon the use of the CCTA Methodology and is consistent with the CCTA Decision, the Hydro Ottawa Decision and the Hydro One Decision.
- The pole attachment rate of \$38.82 per pole per year reflects a 73.69% increase over the existing attachment rate of \$22.35 per pole per year stipulated in the CCTA Decision.
- This Settlement Proposal is preferable to the approach outlined in the Draft Methodology for a number of reasons, as more fully outlined in Appendix “A” below.

Appendix “A”

Comparison to the Draft Methodology

This appendix compares the CCTA Methodology to the Draft Methodology, and provides rationale to support the approach outlined in this Settlement Proposal, which is based upon the CCTA Methodology.

It is worth noting at the outset that the CCTA Methodology relies on input data that uses 2016 actual amounts. By contrast the Draft Methodology relies upon input data that uses 2017 forecast amounts.

No. of Attachers per Pole

- **Draft Methodology:** The Draft Methodology assumes 1.3 telecom attachers per pole, which is based upon data submitted by London Hydro, Hydro Ottawa, Horizon and Hydro One, collectively representing more than 90% of the pole population in the province. This is significantly lower than the CCTA Decision, which assumed 2.5 attachers per pole.
- **This Settlement Proposal:** The Parties have used InnPower’s 2016 actual pole attachment data to arrive at an agreed upon 1.38 attachers per pole.
 - The use of 2016 actuals to determine the number of attachers is consistent with the Hydro Ottawa decision which stated that OEB prefers to use information specific to the utility rather than rely on a projection.⁸
 - Streetlights and Hydro One attachments have been included in the calculation of other attachments, as this is consistent with the methodology used for the Hydro Ottawa Decision.
 - The Parties applied two different methodologies to the actual data available to determine the appropriate number of attachers based on alternative assumptions about how to extrapolate the number of attachments per pole based on the data. These two methodologies are shown in greater detail in the “Attachers per Pole Calculation” tab of the Settlement Model. The difference between these two methodologies is more fully explained in Section A of Appendix “B”. The average of these two methodologies, when all other attachments are included in the calculation is 1.37.
 - The agreed to 1.38 approximates the average of the two different methodologies.

⁸ Hydro Ottawa, at p. 7

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

Vegetation Management

- **Draft Methodology:** In the Draft Methodology, the OEB proposes using an allocation factor of 1/3 of USoA #5135 for vegetation management costs, on the assumption that both LDCs and carriers require and benefit from vegetation management and thus the costs should be shared proportionately in accordance with the useable space on the pole that each entity occupies.
- **This Settlement Proposal:** In calculating the Pole Maintenance Expense, the Parties have agreed to exclude vegetation management costs from Account 5135.
 - The exclusion of vegetation management costs is consistent with the CCTA Methodology, including the Hydro One Decision at pages 8-9.⁹
 - InnPower and Rogers have an existing joint-use agreement which allows InnPower to charge Rogers an amount for vegetation management services (see Appendix “D”). InnPower has not historically charged Rogers any amounts for vegetation management under this provision of the joint use-agreement. However, Rogers and InnPower have agreed, as part of this Settlement Proposal, to meet and discuss an appropriate approach to facilitate InnPower to begin charging for the provision of vegetation management services pursuant to the terms of the existing joint-use agreement going forward. InnPower and Rogers will use commercially reasonable efforts to reach agreement in a timely manner. Disputes will be governed by the terms of the applicable joint-use agreement.
 - To ensure consistent treatment among all wireline attachers with attachments in the communications space, InnPower agrees to charge other such attachers for vegetation management services on the same basis as it charges Rogers if permitted pursuant to the terms of the applicable joint-use agreement.
 - InnPower has forecasted no revenues from joint-use attachers for the provision of vegetation management services as part of this EB-2016-0085 application. For this reason, InnPower agreed with the Parties that a key term of this Settlement Proposal would include:

A request for OEB approval for the creation of a new non-interest bearing deferral account, called the “Vegetation Management Revenues on Joint-Use Poles Deferral Account”, which would be used to record any revenues received by InnPower prior to its next cost of service application for the provision of vegetation management services pursuant to the terms of any joint-use agreement for wireline communications attachments. InnPower

⁹ Decision and Rate Order on Motion to Review dated August 4, 2016, EB-2015-0141 (“**Hydro One**”) at p. 8-9.

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

would dispose of this account to the benefit of ratepayers as part of its next cost of service application.

- This approach makes use of the existing joint-use agreement contractual obligations together with a new deferral account to ensure that ratepayers are made whole for the actual vegetation management costs incurred by InnPower that are attributable to wireline attachers. This more accurately reflects actual vegetation management costs to be incurred in the future, which will differ from amounts recorded in Account 5135 in the past.

Allocation of Direct Costs (Administration and LIP Costs)

- **Draft Methodology:** In the Draft Methodology, the OEB proposes using a total Direct Cost of \$6.15 per pole per year, which reflects a combination of Administration costs (\$2.85 per pole/attacher per year) and Loss in Productivity (\$3.30 per pole/attacher per year).
 - The Administration cost was based on inflation adjusted Administration costs from the Toronto Hydro, Hydro Ottawa and Hydro One applications, which ranged from \$0.90 - \$9.10 per pole per year.
 - The Loss in Productivity amount is consistent with evidence based determinations in both the Hydro One and Hydro Ottawa applications.
- **This Settlement Proposal:** The Parties agree to a total Direct Cost of \$10.45 per pole/wireline attacher per year, which best represents InnPower's actual costs in 2016.
 - Administration costs were calculated to be \$0.92 per pole/wireline attacher per year.
 - The administration costs include InnPower's actual 2016 costs associated with billing preparation, financial reconciliation and annual statements, as well as GIS system updated and permit processing.
 - The costs are based on actual timesheet data for 2016, InnPower's applicable hourly burdened rates for the relevant resources, InnPower's total number of in service poles in 2016, and the number of pole attachments (determined from invoices), and a number of attachers per pole of 1.38.
 - This administration cost exceeds Hydro Ottawa's administration costs of \$0.90 per attacher, and is within the range of administration costs considered by the OEB in the Draft Methodology.

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

- Loss in Productivity costs were calculated to be \$9.53 per pole/wireline attacher per year.
 - The Loss in Productivity calculation reflects the Parties agreement that actual costs for trouble calls of \$51,877 in 2016 which are directly attributable to third party attachers should be included as a Direct Cost (rather than an Indirect Cost). The trouble call costs relate to the costs associated with responding to a trouble call with respect to a wire down, or a tree on wire, and the affected wire is a communications attachment, rather than a distribution wire.
 - The Loss in Productivity calculation also includes actual pole replacement costs from 2016 of \$10,582.71, which accounts for both labour (timesheets and outage management system statistics) and small vehicle use.
 - The Loss in Productivity calculation differs from the one used in the Draft Methodology because InnPower had available more specific facts associated with the costs of trouble costs that are directly associated with communications attachments.

Allocation Methodology

- **Draft Methodology:** The Draft Methodology proposes using a “hybrid equal sharing” methodology¹⁰ to apportion the indirect costs between the distributor and third party pole attachers. This methodology assumes common space is allocated equally to power and third party attachers, and then the third party attacher portion of the costs is divided by the number of third party attachers, which results in an allocation rate of 32.5% to third party attachers.¹¹
- **This Settlement Proposal:** The Parties have agreed to use an “equal sharing” methodology to apportion indirect costs as between InnPower and third party attachers.
 - This methodology is consistent with the CCTA Decision, the Hydro Ottawa Decision and the Hydro One Decision.
 - Using this methodology, the buried depth (6 ft) and clearance space (17.25 ft) is allocated equally between all attachers, including InnPower, the telecommunications space (2 ft) and separation space (3.25 ft) is allocated solely to third party attachers, and the power space (11.5 ft) is allocated solely to Innpower. This results in an allocation rate of 33.93%.

¹⁰ Draft Methodology at p. 30.

¹¹ Draft Methodology at p. 29.

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

Indirect Costs

- **Draft Methodology:** The Draft Methodology uses a five year historical average of Net Book Value amounts in Account 1830, a five year historical average of depreciation expense amounts applied to Account 1830, and a weighted average cost of capital figure to determine the appropriate cost of capital. Based on this methodology, the cost of capital according to the Draft Methodology is 8.25% resulting in a capital carrying cost of \$75.57 per pole.
- **This Settlement Proposal:** In accordance with the CCTA Methodology the Parties have agreed to calculate indirect costs using the last year of actual historical costs available at the time of this settlement (2016).
 - The use of historical year end values for 2016 is consistent with the Hydro Ottawa decision.¹² In that proceeding, Hydro Ottawa cited the CCTA precedent to support its proposal of the use of 2013 historical costs to determine the pole attachment rate. The OEB concurred, stating “The OEB finds that the use of historical costs with no annual inflation adjustment is consistent with the methodology in the 2005 decision”¹³
 - In determining the net embedded cost per pole, the Parties have agreed to use the 2016 net book value (“NBV”) of Account 1830. In determining the depreciation expense, the Parties have agreed to use 2016 depreciation expense. Finally to determine the appropriate cost of capital, the parties have agreed to use the 2016 cost of capital (as further described in Section D of Appendix “B”).
 - The use of 2016 actuals better represents InnPower’s actual indirect costs than the use of a five year historical average methodology. This is because InnPower has experienced some of the highest growth in the number of customers of any distributors in the Province of Ontario with actual growth rates for residential and GS customers of 2.44% in 2014, 2.35% in 2015, 2.26% in 2016, and forecasted growth of 2.35% in 2017.¹⁴ Consequently there has been a significant increase in the number of new poles in Account 1830 and so the application of a five year historical averages for NBV and depreciation expense and cost of capital will not properly reflect InnPower’s actual factual circumstances. Rather the use of historical averages will systematically understate these values for a high growth utility like InnPower.
 - Specifically, for InnPower a five year historical average between 2012-2016 results in a NBV in Account 1830 of \$7,323,388 and a depreciation expense of

¹² Hydro Ottawa at p. 12.

¹³ Hydro Ottawa at p. 9.

¹⁴ InnPower Argument in Chief, dated October 6, 2017 Table 1 at p. 23.

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

\$181,217. This is shown in the Settlement Model at the tab titled “Average NBV for Account 1830”. Actual NBV in Account 1830 at the end of 2016 was \$9,022,429 and actual depreciation expense in 2016 was \$254,232. As a result, the averaging methodology systematically understates InnPower’s known NBV by \$1,699,041 and depreciation expense by \$73,015.

Power Deduction Factor

- **Draft Methodology:** The Draft Methodology uses a power deduction factor of 15%, using a methodology developed by Hydro One.
- **This Settlement Proposal:** The Parties have agreed to that a power reduction factor of 5% is appropriate for InnPower.
 - Hydro One appears to have allocated a fair number of costs associated with power fixtures (brackets, cross arms, braces, extensions, arms, guards, insulator pins, suspension bolts and transformer racks and platforms) into Account 1830, which resulted in a higher power deduction factor to ensure that communications attachers are not required to pay for costs associated with power fixtures.
 - InnPower’s accounting practice was to allocate the majority of costs associated with power fixtures to Account 1835 rather than Account 1830. The amounts recorded to Account 1835 have not been included in the calculation of the wireline pole attachment rate because these amounts relate solely and directly to overhead power lines and associated power fixtures.
 - InnPower reviewed its work orders and invoices related to Account 1830, and determined that the total common cost in Account 1830 are \$1,022,566.19 and the Power Only Fixture Costs are \$44,914.66. This results in an allocation factor of 4.21% based on 2016 actuals. This is shown in the Settlement Model attached to this Settlement Proposal at the tab titled “Power Deduction Factor”.
 - The 5% power deduction factor chosen by the Parties is a close approximation of the actual costs incurred that are specific to power specific assets in 2016.
 - This approach represents the best approximation of the power deduction factor for InnPower to account for the inclusion of power specific assets, and is consistent with the Hydro Ottawa Decision.¹⁵

Inflation

- **Draft Methodology:** The Draft Methodology implements an annual inflationary adjustment mechanism to the single province-wide rate. The adjustment will be based on

¹⁵ Hydro Ottawa at p.13.

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

the OEB's Input Price Index with no productivity and stretch factor applied. The rationale for the inclusion of inflation is to provide an adjustment factor to minimize the impact of inflation over time, while minimizing the impact that might occur when rates are rebased in the event that a utility specific rate is approved.¹⁶

- **This Settlement Proposal:** The Parties agreed to not adjust for inflation. The costs utilized to establish this InnPower specific pole attachment rate were based on the most current historical year data.
 - This is consistent with the methodology used in the Hydro Ottawa Decision, which is based on the most current historical year data: “The OEB finds that the use of historical costs with no annual inflation adjustment is consistent with the methodology in the 2005 decision.”¹⁷

¹⁶ Draft Methodology at p. 34

¹⁷ Hydro Ottawa at p. 9.

Appendix “B”

Updates to the Evidence

This appendix explains the updates and corrections agreed to by the Parties as part of this Settlement Proposal to the current evidentiary record in InnPower_APPL_Pole Attachment_20171218.xlsx filed as part of InnPower’s IR responses (“**IR Spreadsheet**”).

A: Administration Costs Per Pole

The total Administrative cost changed from \$0.99 per pole in the IR Spreadsheet to \$0.92 in the Settlement Proposal because the parties determined that the number of attachers per pole should be 1.38 as opposed to 1.09.

InnPower had used 1.09 which was extrapolated from a field survey of 1/5 of IPC’s service territory.

During the course of the settlement, the Parties utilized two different methodologies to the actual data available to determine the appropriate number of attachers based on alternative assumptions about how to extrapolate the number of attachments per pole based on the data. These two methodologies are shown in greater detail in the “**Attachers per Pole Calculation**” tab of the Settlement Model.

Both methodologies factor in known data derived from a field audit counting communications attachments on 20% of InnPower’s poles, the number of attachments per attacher, the actual number of invoices issued to attachers, and the total number of other attachers including Hydro One and street lights.

The two methodologies calculate a number of attachers per pole of 1.592 and 1.149 respectively. The difference between these two methodologies is attributable to the fact that the field audit only assessed 20% of the total pole population. The different methodologies extrapolate that data across the entire pole population in different ways.

The average of these two methodologies, when all other attachments are included in the calculation is 1.37. The agreed to 1.38 approximates the average of the two different, equally valid, methodologies.

As a direct result of the change from 1.09 to 1.38, the total number of poles with attachers changed from 6,095 in the IR Spreadsheet to 6,558 in this Settlement Proposal.

B. Loss in Productivity

The total LIP costs per pole in the IR Spreadsheet was \$4.00 per pole, while in the Settlement Model the total LIP cost per pole was \$9.53, with a total LIP cost per pole per attacher was \$9.81.

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

This change arose during the course of discussions in the settlement conference. The Parties identified a concern that costs associated with trouble calls were included in the IR Spreadsheet under both the Loss in Productivity category (for each of Wires Down and Tree on Line) and in the Pole Maintenance Costs under Account 5135.

As part of this settlement, the Parties agreed that Trouble Call should only be accounted for once in the model.

InnPower confirmed that the actual costs for trouble calls in 2016 which are directly attributable to third party attachers was \$51,877.

Since these trouble call costs relate to the costs associated with responding to a trouble call with respect to a wire down, or a tree on wire, and the affected wire is a communications attachment, rather than a distribution wire, the Parties agreed that these costs should be included as a Direct Cost as a known and calculable Loss in Productivity.

C. Pole Maintenance Expense

InnPower had forecasted a total Pole Maintenance Expense of \$17.79 per pole in the IR Spreadsheet versus \$3.03 in the Settlement.

Part of this change is attributable to the Parties' agreement to remove costs relating to Trouble Calls (Account 5135) from the Indirect Costs, because those costs are now already captured as a Direct Cost under Loss in Productivity (as described in item B above).

A second part of this change related to concerns raised by the Intervenors about the relatively low account balance in Account 5120 as it related to Pole Testing Costs. InnPower confirmed as part of the settlement that pole testing is contracted out to a third party, and that historically those costs have not been recorded in Account 5120. InnPower further confirmed that a third party vendor that does pole testing for InnPower, and that the total invoiced costs for pole testing work completed in 2016 was \$26,646.

Based on these facts, the Parties agreed that the known pole testing costs in 2016 should be included in the determination of Pole Maintenance Costs.

Finally, in the IR Spreadsheet InnPower had included \$39,794 in costs associated with Account 5125. Upon further exploration during the settlement, the Parties agreed that these costs should be removed since the costs related more directly to the maintenance of overhead conductors and devices, and were not appropriate to attribute to third party communications attachers.

D. Capital Carrying Costs

The Cost of Capital in the IR Spreadsheet was 6.9%. This was the 2016 net cost of capital of InnPower from the EB-2013-0139 decision of 6.12%, notionally grossed up for taxes.

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

Prior to the settlement conference, OEB Staff asked InnPower to explain their gross-up methodology. In completing this explanation, InnPower identified an error. The actual grossed up Cost of Capital should be 6.78%. The tax rate utilized to gross up the cost of capital is 15.5%.

The following table shows the calculation of the pre-tax cost of capital arising from the 2013 Settlement in EB-2013-0139.

The Parties agree that the corrected grossed-up cost of capital of 6.78% is appropriate.

	Cost of Capital	Deemed Capital Structure	Net Cost of Capital	Gross Up Cost of Capital
LT Debt	4.36%	56%	2.44%	2.44%
ST Debt	2.07%	4%	0.08%	0.08%
Equity	8.98%	40%	3.59%	4.25%
			6.12%	6.78%

Tax Rate	15.50%
----------	--------

E. The Allocation Factor

The Allocation Factor in the IR Spreadsheet changed from 39.85% to 33.93% in the Settlement Proposal, as a direct result of the change in the number of attachers per pole from 1.09 to 1.38.

InnPower Corporation
EB-2016-0085
Settlement Proposal (Wireline Pole Attachment Rate)

Appendix “C”

Appendix 2-H Other Operating Revenue

Appendix 2-H has been updated to reflect the forecasted other revenue for Account 4210 resulting from the Settlement Proposal of \$269,217, assuming the new pole attachment rate is in effect over a 12 month period.

This is a reduction in forecasted other revenue in Account 4210 provided in Appendix 2-H included in the Nov. 27, 2017 evidence filed in response to Procedural Order No. 7,¹⁸ which was calculated based on an assumed pole attachment rate of \$64.24.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2013 Actual	2014 Actual	2015 Actual ¹	Actual Year ²	Bridge Year ²	Test Year
		2013	2014	2015	2015	2016	2017
	<i>Reporting Basis</i>	<i>CGAAP</i>	<i>CGAAP</i>	<i>CGAAP</i>	<i>MIFRS</i>	<i>MIFRS</i>	<i>MIFRS</i>
4210	Rent from Electric Property	-\$ 153,289	-\$ 169,620	-\$ 161,207	-\$ 162,034	-\$ 162,034	-\$ 269,217
4225	Late Payment Charges	-\$ 73,904	-\$ 84,703	-\$ 96,925	-\$ 96,925	-\$ 111,252	-\$ 111,252
4235	Specific Service Charges	-\$ 116,157	-\$ 139,676	-\$ 156,170	-\$ 156,170	-\$ 159,223	-\$ 170,000
4245	Deferred Revenues - Contributions	\$ -	\$ -	\$ -	-\$ 313,330	-\$ 376,051	-\$ 522,116
4355	Gain on Dispositions	\$ -	-\$ 4,450	-\$ 440,397	-\$ 440,397	\$ 8,791	\$ 183,094
4375	Revenues from Non Utility Operations	-\$ 682,460	-\$ 801,855	-\$ 775,120	-\$ 775,120	-\$ 1,354,978	-\$ 1,087,311
4380	Expenses of Non Utility Operations	\$ 627,785	\$ 718,395	\$ 689,823	\$ 689,823	\$ 1,250,847	\$ 983,861
4390	Misc Non Operating Expense	-\$ 11,015	-\$ 10,882	-\$ 30,116	-\$ 30,116	-\$ 57,992	-\$ 60,000
4405	Interest and Dividend Income	-\$ 26,558	-\$ 39,974	-\$ 27,918	-\$ 27,918	-\$ 29,388	-\$ 30,000
	Total	-\$ 435,598	-\$ 532,765	-\$ 998,029	-\$ 1,312,186	-\$ 991,280	-\$ 1,082,941
	Specific Service Charges	-\$ 116,157	-\$ 139,676	-\$ 156,170	-\$ 156,170	-\$ 159,223	-\$ 170,000
	Late Payment Charges	-\$ 73,904	-\$ 84,703	-\$ 96,925	-\$ 96,925	-\$ 111,252	-\$ 111,252
	Other Operating Revenues (4210 & 4245)	-\$ 153,289	-\$ 169,620	-\$ 161,207	-\$ 475,364	-\$ 538,084	-\$ 791,333
	Other Income or Deductions (4355, 4375, 4380, 4390, 4405)	-\$ 92,248	-\$ 138,766	-\$ 583,728	-\$ 583,728	-\$ 182,721	-\$ 10,356
	Total	-\$ 435,598	-\$ 532,765	-\$ 998,029	-\$ 1,312,186	-\$ 991,280	-\$ 1,082,941

¹⁸ <http://www.rds.oeb.ca/HPECMWebDrawer/Record/591988/File/document>

InnPower Corporation
EB-2016-0085

Settlement Proposal (Wireline Pole Attachment Rate)

Appendix “D”

Excerpt from Pole Attachment Agreement between Innisfil Hydro Distribution Systems Ltd., (now InnPower Corporation) and Rogers Cable Communications Inc.:

ARTICLE 10 – LINE CLEARING

- 10.1 The Owner and the Licensee agree that vegetation management is required for the ongoing reliable provision of electricity and telecommunication services. The trimming or removing of trees, underbrush or any other items as required to establish clearance for the Licensee's Attachments shall be the sole responsibility of the Licensee. The Licensee, or its contractor as approved by the Owner, shall undertake the trimming or removing of trees, underbrush or any other items as required by the Licensee for the Licensee's purposes in the Communications Space, having regard for all safety, technical and engineering concerns of the Owner. If in the sole but reasonable discretion of the Owner, the vegetation on or around the Licensee's plant is or may be damaging to the Owner's existing plant or electrical distribution system or aesthetics, the Licensee shall correct the situation to the satisfaction of the Owner upon notification by the Owner. Nothing in this clause excuses the Licensee of liability in the event of damage to the Owner's plant because of such vegetation. If the Licensee fails to engage in the requisite trimming or removal within seven (7) days of notification from the Owner, the Owner may undertake such work or arrange for it to be completed, all at the risk and expense of the Licensee, and the Owner shall submit an invoice to the Licensee for the reasonable cost of such work, which invoice shall be paid by the Licensee in accordance with Article 13.
- 10.2 The Licensee and Owner may, by mutual agreement, make arrangements regarding provision of tree trimming or line clearing services. If such arrangements are made between the Licensee and Owner, the Owner shall inform the Licensee of the timing, location, cost, and extent of the tree trimming or line clearing services to be undertaken on their behalf in advance of the commencement of the tree trimming or line clearing services.
- 10.3 Should any extraordinary services, such as but not limited to tree trimming or line clearing services after storms, be required in order to establish clearances for the Licensee's Attachments for operations, maintenance and safety, the cost of such services shall be the sole responsibility of the Licensee. In the event that such extraordinary services are required, in the sole but reasonable discretion of the Owner, the cost of such extraordinary services undertaken by the Owner shall be charged to the Licensee in accordance with the provisions of Article 13.