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November 13, 2017

Delivered by Email, RESS & Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: InnPower Corporation
2017 Rate Application (EB-2016-0085)
Reply Submissions of InnPower Corporation

Please find enclosed the Reply Submissions of InnPower Corporation.

If you require any further information, please contact the undersigned.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Original signed by Ada Keon on behalf of John A.D. Vellone

Per:

John A.D. Vellone

cc: Intervenors of record in EB-2016-0085

EB-2016-0085

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

AND IN THE MATTER OF an Application by InnPower Corporation under Section 78 of the Act for an order approving just and reasonable rates and other charges for electricity distribution to be effective July 1, 2017.

REPLY SUBMISSIONS OF INNPOWER CORPORATION

November 13, 2017

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INTRODUCTION:

1. InnPower Corporation ("**InnPower**") makes these written submissions in reply to the submissions of Ontario Energy Board staff ("OEB Staff") received October 24, 2017 and subsequently amended on October 26, 2017, the School Energy Coalition ("SEC") received October 30, 2017 and the Vulnerable Energy Consumer Coalition ("VECC") received October 31, 2017 in respect of an Application filed by InnPower on November 28, 2016, as amended, under Section 78 of the *Ontario Energy Board Act, 1998* seeking an order of the Ontario Energy Board (the "**OEB**") approving just and reasonable rates and other charges for electricity distribution to be effective July 1, 2017 (the "**Application**", Board file number EB-2016-0105). OEB Staff, SEC, and VECC shall be referred to collectively as the "**Parties**."

GENERAL THEMES

2. These reply submissions are organized around the following general themes.

3. InnPower services a very large rural territory spanning 292 square kilometers located south of Barrie with a relatively small customer base (roughly 16,300 in residential and general service customers). [1] Like other distributors that serve a primarily rural service territory, InnPower's total cost per customer (and OM&A per customer) statistics do not compare favorably to urban and suburban distributors that service many more customers on much shorter lengths of line. By contrast, InnPower's total cost per km of line (and OM&A per km of line) statistics are much better than urban and suburban comparators.

4. These facts arise from the geography of and the development pattern within InnPower's service territory. These are factors that are entirely outside of management's control. It is because of these factors that InnPower's customers together with Hydro One rural customers and customers in Algoma; Atikokan; Chapleau; Lakeland (former Parry Sound Power service area); Northern Ontario Wires; and Sioux Lookout each qualify for Distribution Rate Protection ("**DRP**"), a government program that is designed to help

[1] Exhibit 2, Appendix "A", Distribution System Plan filed November 28, 2017 at pages 9-11.

alleviate the recognized higher costs of serving rural and remote electricity consumers.

5. Each of the Parties fault InnPower for having high distribution rates. Each of the Parties fault InnPower because they qualify for DRP. This is neither just nor reasonable. If the Parties do not believe that DRP is justified as a provincial program, or that no utilities should qualify for this program, this Application is not the forum to air those grievances.

6. What none of the Parties acknowledge is that higher rates are a natural consequence of providing mandatory service in a rural service area with a low population density. This is the very reason DRP was created as a policy of the Government of Ontario, as it was the same reason for the creation of the Rural and Remote Electricity Rate Protection by the former Ontario Hydro.

7. Moreover none of the Parties acknowledge that when InnPower is analyzed using the OEB's own Pacific Economics Group ("**PEG**") econometric benchmarking tool, InnPower's total costs of providing service has at all times remained within +/-10% of predicted costs.

8. Put another way, the OEB's econometric benchmarking tool recognizes that InnPower's costs will – by the very nature of their service territory – be higher than other areas of the province. InnPower's performance in the benchmarking did slide shortly after the new building went into service – however, the need and prudence of this building was already demonstrated as part of a previous incremental capital module ("**ICM**") Application. Even with the new building, InnPower has at all times been in, and remains in, Group 3 in terms of efficiency performance vis-à-vis other distributors in Ontario.

9. In this context, and as outlined in Table 1 of InnPower's Argument-in-Chief, InnPower is also managing some of the highest growth rates seen in the Province of Ontario. Unfortunately, this new growth is scattered across the InnPower service area in a number of different developments (Friday Harbour, Barrie South – Salem, Barrie South – Hewitt, Alcona & Sleeping Lion, Lefroy and Highway 400). This is clearly illustrated by the map shown at pg. 13 of the InnPower Distribution System Plan ("**DSP**"), which is reproduced under the operating, maintenance & administration ("**OM&A**") submissions below for

ease of reference.

10. The unique confluence of a rural service territory with a small number of customers, together with a very high growth rate scattered across the rural territory, raises a recognized cost driver known as "spatial density". An understanding of customer growth combined with increasing spatial density is necessary for the OEB to understand the actual drivers of the revenue deficiency in this Application. For this Application, one driver (growth) cannot be considered in isolation without the other (spatial density).

11. In this context, the OEB can take comfort in the new management team that has recently joined InnPower. Mr. Malcolm and his entire team have demonstrated a commitment to improving utility performance, and better responding to customer needs and preferences. This commitment is demonstrated throughout the evidentiary record and was summarized at paragraphs 3-10 of the Argument-in-Chief.

12. It is further demonstrated below in these Reply Submissions in direct response to concerns raised by SEC in their submissions about the charges to InnServices not properly accounting for certain overhead costs. InnPower was and is committed to ensuring that its affiliate services are priced appropriately in accordance with the provisions of the *Affiliate Relationship* Code. Given this, InnPower agrees that it should adjust its affiliate charges to account for relevant overheads costs for both Financial Services and Water and Waste Water Services. InnPower management thanks counsel to SEC for bringing this concern to their attention. This change will result in an additional $166,230 in revenue from InnServices, amounts that will further reduce the OM&A costs for InnPower ratepayers. This is in addition to the additional forecasted revenues of $112,981 outlined in Undertaking J1.6, which amounts will also reduce the OM&A costs for InnPower ratepayers. The total reduction in OM&A costs arising out of increased revenues derived from shared services with InnServices is $279,211.

13. In this context, disagreements on matters at issue in an Application are expected, and we address each of those disagreements below. However, the Board should resist calls from certain Parties to impose some form of "penalty" on InnPower. As more fully detailed

below, some of these suggestions are contrary to established OEB policy and others are contrary to applicable law. There is no basis in law, policy or fact to impose such a penalty.

14. But more to the point, imposing a "penalty" on InnPower would not be in the public interest. Rather, doing so would undermine the ongoing financial viability of the utility.

15. As explained in Argument-in-Chief, InnPower is consistently, year-over-year, earning less than the deemed rate of return in rates. In addition, InnPower earned more than 300 basis points less than the OEB's deemed ROE in each of 2012, 2014 and 2016.

16. In response to this, and in direct support to help improve InnPower's financial position, InnPower's shareholder provided InnPower with a $1,600,000 equity injection in 2016, the payment of dividends have been suspended since the last quarter of 2014 and have not been re-instated since that date, and InnPower has utilized a loss-carry-back strategy to further improve its liquidity position.

17. In this context, InnPower is not yet clear of financial risk. Yes, its liquidity position is improved and a new management team is in place, with a new philosophy and a new approach that is focused on driving operational efficiencies and is directly in-tune with customer needs and preferences. But this new management team needs the OEB's help. They need the resources necessary to successfully operate and turn around performance at this utility going forward.

DETAILED REPLY

18. The Parties' submissions focus principally on the size of the revenue deficiency associated with the Application, and the associated rate impacts.

19. There appears to be some confusion among the Parties regarding the revenue deficiency associated with this Application. OEB Staff cite a revenue deficiency of $3,348,878, with reference to the cross-reference document filed by InnPower on October 11, 2017.[2] By

[2] OEB Staff submissions at pg. 3.

contrast, SEC cites a revenue deficiency of $2,176,636 in Table 1 of its argument.[3]

20. The source of the difference arises from the inclusion of a MAX formula in the Income Tax on Taxable Income line of the Revenue Deficiency tab of the RRWF (Tab 8, Row 13) embedded in all versions of the RRWF filed prior to the technical conference. This is reflected in the cross-reference document. Following the technical conference, InnPower retained Mr. Bacon to complete the RRWF to assist with reconciling the models and eliminating data errors. The RRWF filed following the technical conference removes the MAX function, as was done in the interrogatory version of the RRWF, since to do otherwise would lead to a non-intuitive result. Specifically, the problem with the MAX formula is that when Income Tax on Taxable Income happens to be negative (and thus the MAX function kicks in) it fundamentally changes the calculation of the Revenue Deficiency (Tab 8, Row 1) in the RRWF such that it is no longer equal to the difference between distribution revenue at existing rates and distribution revenue at proposed rates. That is an odd and counterintuitive result.

21. In this regard, InnPower agrees with SEC's summary Table 1. The cited revenue deficiency of $2,176,636 is equal to the difference between revenue at distribution existing rates and distribution revenue at proposed rates is correct.

22. Mr. Malcolm spoke directly to this revenue deficiency during examination in chief, acknowledging that an $8.14 residential rate increase is still a large increase. Mr. Malcolm went on to quantify the key drivers of this increase:[4]

a. approximately 55% is attributable to increases in depreciation and cost of capital associated with a significant growth in rate base of approximately $20 million (from approximately $33 million to $55 million) since 2013;
b. approximately 30% is attributable to increases in OM&A expenditures since 2013;
c. approximately 9% is attributable to an increase in PILS since 2013; and
d. approximately 5% is attributable to an increase in property taxes since 2013.

[3] SEC submissions at pg. 3.
[4] Transcript Vol. 1 dated Oct. 3, 2017 at pg. 9, line 1 to pg. 11, line 16.

23. This reply will step through each of the cost drivers in-turn, and address the submissions raised by the Parties in respect of each. The reply will then address the submissions of the Parties in respect of various other matters, including other revenues, cost allocation and rate design.

24. OEB Staff's suggestion that the InnPower revenue deficiency "is much higher than the average requested revenue deficiency the OEB has seen in the last four years of CoS applications, which is 14%" is, however, misleading. OEB Staff's comparison is not supported on the evidentiary record. Further, OEB Staff provided no support for the calculation of the 14% or for the appropriateness of the comparison it makes. InnPower has had no opportunity to ask questions or conduct discovery on this purported benchmark, in direct violation of its procedural rights and the rules of natural justice. For these reasons alone the OEB should disregard this comparison. In addition, OEB Staff's comparison is fundamentally misleading because it does not adjust for the inclusion of the ICM amounts that were already approved by the OEB or the ending of ICM rate riders. OEB Staff's benchmark also fails to account for the high growth seen by InnPower in its service territory.

A. OM&A COSTS (ISSUE 1.2)

25. OEB Staff argue that the Board should cut InnPower's proposed OM&A budget in the test year by 7%, or $429,000.[5] SEC argues for an OM&A reduction of $650,000 in the test year, although SEC agrees that these reductions should be adjusted downwards if additional costs are allocated to Revenue Offsets.[6] VECC believes that a reduction in OM&A between $800,000 and $500,000 is warranted as there are no outstanding circumstances that warrant an increase in these costs in excess of inflation.[7]

A.1 Cost Drivers Outside of Management's Control

26. Each of the Parties criticize InnPower for having cost increases that are driven by factors

[5] OEB Staff Submissions at pg. 28.
[6] SEC Submissions at para. 1.3.2 and 2.4.5.
[7] VECC Submissions at para. 14.

that are entirely beyond management's control. They do not attempt to account for these external cost drivers, rather the Parties largely ignore these cost drivers. There are three such cost drivers that are relevant to this Application. InnPower submits that the Board should consider each in its analysis of InnPower's OM&A costs.

27. The first is inflation. It is generally understood that utility costs will be driven by inflationary increases in labour and material costs. This is why the PEG consistently recommends that inflation be accounted for by the Board in its rate setting methodology. The OEB's inflationary increases since the last rebasing are 1.70% in 2014, 1.60% in 2015, 2.10% in 2016 and 1.90% in 2017.

28. It is typical for the Board to also want to incent a certain level of productivity performance improvements into its rate setting methodology. The Board has done so on a province-wide basis by using a sophisticated econometric benchmarking model that is prepared by PEG to assign stretch factors to utilities, based on an assessment of total cost performance. InnPower has been assigned to Group 3 in the PEG benchmarking analysis for each of the years 2013-2017. This would result in a stretch factor of 0.3% for each of the years.

29. The second factor is customer growth. InnPower is a very high growth utility. This was clearly highlighted in Table 1 of InnPower's Argument-in-Chief, which illustrates 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.

30. None of the Parties have accounted for this high level of growth in their submissions. Unlike other utilities, InnPower's costs are being driven by the fact that it is actually delivering <u>more services</u> to <u>more customers</u>.

31. It is typical for the Board to weight customer growth by a weighting factor of 0.44. This weighting factor has empirical backing from PEG in the Final Report to the Ontario Energy Board titled *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario* issued November 2013, as amended (the "**PEG Report"**):

> "*At the sample mean, a 1% increase in the number of customers raised cost by*

.44%."[8]

32. This empirically validated and traditional approach for treating growth as a recognized OM&A cost driver stands in direct contradiction to OEB Staff's unsubstantiated suggestion that future load growth must not result in any increased OM&A costs.[9] InnPower submits that the Board should not depart from its traditional policy as it relates to the impact of growth as a cost driver.

33. The third is spatial density, which can be measured as total circuit km of line divided by total geographic service area (sq. km). This factor does not often arise in cost of service applications. However, it is directly relevant to this Application where InnPower must manage high customer growth that is spread out across a large rural service territory, driving sizeable increases in the average circuit km of line.

34. The importance of spatial density is best explained in the PEG Report:

> "In addition to output quantities and input prices, electricity distributors confront other operating conditions due to their special circumstances. Unlike firms in competitive industries, electricity distributors are obligated to provide service to customers within a given service territory. Distribution services are delivered directly into the homes, offices and businesses of end-users in this territory. Distributor cost is therefore sensitive to the circumstances of the territories in which they provide delivery service.
>
> One important factor affecting cost is customer location. This follows from the fact that distribution services are delivered over networks that are linked directly to customers. The location of customers throughout the territory directly affects the assets that utilities must put in place to provide service. The spatial distribution of customers will therefore have implications for network cost.
>
> **The spatial distribution of customers is sometimes proxied by the total circuit km of distribution line**, or the total square km of territory served. Provided customer numbers is also used as a cost measure, **these variables will together reflect the impact of different levels of customer density within a territory on electricity distribution costs.**"[10]

35. This is why every utility in Ontario must report total circuit km of line as part of their

[8] PEG Report at pg. 59.
[9] OEB Staff Submissions at pg. 28.
[10] PEG Report pgs. 53-54.

RRR filings. A review of the publicly available statistics in the Electricity Distributor Yearbooks[11] shows that, for InnPower, the total circuit km of line has increased from 793 in 2013 to 818 in 2014 (a 3.15% increase), to 833 in 2015 (a 1.83% increase),[12] to 843 in 2016 (a 1.2% increase). The total circuit km of line at the end of 2017 is forecast to be 17 km of single phase and 10 km of three phase for a total of 27 km. That will increase InnPower's total from 843 in 2016 to 870 km in 2017 (a 3.2% increase).[13] Over this same period of time, InnPower's total geographic service territory remained constant at 292 sq. km. This means that the spatial density of InnPower's distribution system has been increasing at a rate equivalent to the growth in total circuit km of line.

36. The evidence in this case is clear. InnPower services a very large rural territory spanning 292 square kilometers located south of Barrie with a relatively small customer base (roughly 16,300 in residential and general service customers).[14] Like any other rural distributor in Ontario, InnPower's scorecard performance on total cost per customer (or OM&A per customer) is poor relative to other utilities that service more densely populated urban and suburban centres. Similarly, when considering total cost per km of line, InnPower performs much better than most urban and suburban LDCs. This is also why, as a matter of provincial policy, InnPower customers benefit from rate protection applicable to rural customers.

37. The evidence also illustrates that new customer growth is not geographically concentrated. Rather growth is happening across a number of different developments (Friday Harbour, Barrie South – Salem, Barrie South – Hewitt, Alcona & Sleeping Lion, Lefroy and Highway 400) that are spread out across InnPower's rural service territory. This is illustrated by the map shown at pg. 13 of the InnPower DSP, which is reproduced below for ease of reference.

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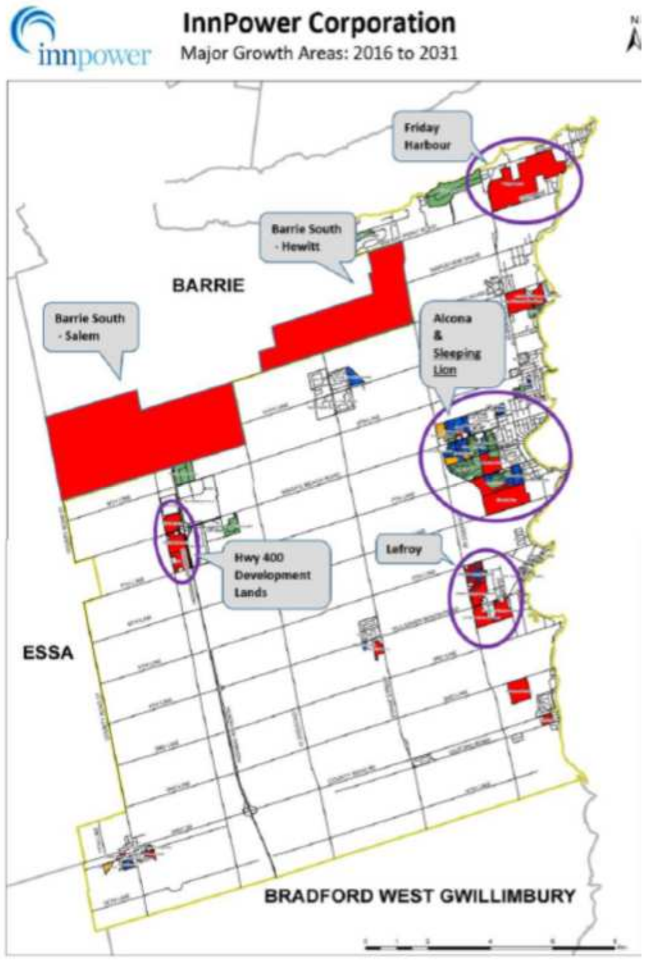
[11] https://www.oeb.ca/utility-performance-and-monitoring/natural-gas-and-electricity-utility-yearbooks
[12] This was the most current information available at the time InnPower completed its DSP, back in 2016.
[13] The figure of 27km is the sum total of km of lines to be completed via the DSP in 2017.
[14] Exhibit 2, Appendix "A", Distribution System Plan filed November 28, 2017 at pages 9-11.



38. Given this unique confluence of facts, InnPower submits that the Board must also consider spatial density when assessing cost drivers that are outside of management's control. Doing so is not without empirical backing. The PEG Report states:

> "With respect to a distributor's average circuit km of line over the 2002-2012 period, it can be seen that a 1% increase in average circuit km raised distribution cost by 0.29%.
>
> […]
>
> The circuit km variable clearly has an output-related dimension, because it reflects customers' location in space and distributors' concomitant need to construct delivery systems that transport electrons directly to the premises of end-users."[15]

A.2 Adjustment to Account for Shared Services with InnServices

[15] PEG Report at pg. 59.

39. InnPower's forecasted test year OM&A costs must also be adjusted to reflect the incremental OM&A costs that are directly attributable to InnServices pursuant to the Financial Services Agreement and the Water and Waste Water Billing Agreement. This portion of OM&A costs have grown in excess of inflation and growth because InnPower is doing <u>more work</u> for InnServices under these two agreements. However, these incremental costs are directly offset by incremental other revenues paid by InnServices. Consequently, the OEB must make corresponding adjustments when considering InnPower's OM&A growth trends.

40. These other revenues would not be earned by InnPower, and ratepayers would not benefit from them, except that InnPower has incurred associated incremental OM&A costs. This is shown in the Table below, which summarizes the relevant information from Appendix 2-N:

Year	Name of Company		Services Offered	Price for Service	Cost of the Service
	From	To		($)	($)
2013	InnPower	Town of Innisfil	Water and Waste Water Billing	$251,044	$190,269
2017	InnPower	InnServices	Water and Waste Water Billing	$245,000	$193,530
2017	InnPower	InnServices	Financial Services	$232,198	$229,899

41. In this context, it is necessary to distinguish how InnPower accounted for these different shared services in its Application. For Water and Waste Water Billing the revenue was accounted for in the Other Revenue account. For Financial Services, however, the burdened labour costs were removed from the administrative labour lines in the OM&A expense accounts (Executive, Management and Admin Staff) while the incremental revenue (1% admin fee) was added to the Other Revenue accounts.

42. If incremental Financial Services were instead added to Other Revenues, then to ensure an accurate analysis of OM&A trends the OEB should reduce OM&A to reflect the incremental costs associated with these additional shared services which are being offset by incremental other revenues.

43. During the oral hearing, InnPower acknowledged that it is now expecting that revenues from Financial Services are going to be higher than originally forecasted. In response to Undertaking J1.6, InnPower explained that the revenue is now forecasted to be $346,309.

As explained in this undertaking response, to remain consistent with the original Application, this increase needs to be accomplished by a reduction in OM&A of $112,981. **<u>This change is not reflected in the forecasted test year OM&A budget of $5.990M.</u>**

44. In the alternative, if the OEB prefers to allocate the incremental Financial Services revenues directly to Other Revenues, then to ensure an accurate analysis of OM&A trends the OEB should reduce the test year OM&A by $112,981 to reflect the incremental costs associated with these additional shared services which are being offset by incremental other revenue.

45. Finally, as noted in the section below on "*Affiliate Services*", in consideration of the submissions of SEC, InnPower acknowledges that $125,240 in additional charges for Water and Waste Water Billing and $40,990.49 in additional charges for Financial Services are appropriate to better account for overhead OM&A costs associated with providing these services to InnServices. As acknowledged by SEC in its submissions,[16] to ensure an accurate analysis of OM&A trends the OEB should reduce the test year OM&A to reflect these incremental costs associated with these additional costs that will now be paid for by InnServices.

A.3 Other Exceptional OM&A Cost Drivers

46. InnPower's forecasted test year OM&A costs should also account for exceptional OM&A cost drivers.

47. The largest of these cost drivers is the increased OM&A costs associated with the new administrative building, as shown in response to undertaking JT1.8 of $138,713.92. It is worth noting that page 12 of the EB-2014-0085 Board approved settlement agreement states that:

> "*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).*"

48. In agreeing with both the need and prudence of the new building in the Settlement, the parties all explicitly recognized that additional incremental OM&A costs would be

[16] SEC Submissions at para. 1.3.2.

incurred. It would be unreasonable to now deny these incremental costs that are directly attributable to the new building, which was clearly needed and necessary.

49. The second exceptional OM&A cost driver was the introduction of Bill 8 legislation for ON1Call, which drove a dramatic increase in cable-locate volumes from 1,917 in 2012, to 3,075 in 2013 to 4,449 in 2014 and in-turn drove incremental OM&A costs in Customer Work Orders.[17] Specifically, the introduction of ON1Call was directly attributable to increases in Customer Work Orders of $130,984.[18] The vast majority of these costs (90%) are paid to a third party contractor for performing locate services.[19]

50. The third major exceptional OM&A cost driver was an adjustment to employee pension and benefits of $60,500 that was driven directly due to the transition to IFRS.[20]

51. The fourth major exceptional OM&A cost driver was the increase in the OEB fee assessment from $49,000 in 2013 to $68,453 based on 2016 actuals.[21]

A.4 Proposed Reductions in FTEs

52. InnPower is proposing to hire no new FTEs in the test year.

53. This stands in contrast to the plan put forth by the previous management team in the Custom IR Application, which proposed hiring 7 new FTEs in the test year to manage increased workload associated with high growth. Contrary to the unsubstantiated assertions of OEB Staff,[22] the details about each of these incremental FTE positions that were eliminated are explained at pages 21 to 24 of Exhibit 4 of the June 3, 2016 Custom IR Application which is readily available on the evidentiary record in this proceeding. If OEB Staff wanted further evidence about why or how the need changed for any of these positions, they had ample opportunity to ask questions during both the written and oral discovery phases of this proceeding. Indeed, one of the roles of OEB Staff in these hearings is to elicit evidence onto the record that they believe is necessary to assist the Board in making a decision on the issues. OEB Staff failed to do so.

[17] Exhibit 4 dated Nov. 27, 2016 at pg. 17 lines 4-16.
[18] 4-Staff-49 at pg. 160, lines 24-32. See also Undertaking J1.3.
[19] Undertaking J1.3.
[20] Ibid. at pg. 18, lines 14-15.
[21] 4-Staff-53(f) and Appendix 2-M.
[22] OEB Staff submissions at pg. 9.

54. Given that no new FTEs are proposed in the test year, each of OEB Staff, VECC and SEC argue that the OEB should instead cut the costs associated with three FTE vacancies that InnPower is currently attempting to fill. These types of proposals are opportunistic, and are not in the public interest.

55. Like any other company, InnPower's employees leave, retire, go on maternity leave, go on sick leave, and go on disability – leaving InnPower with less than a full complement of staff to provide services to its customers at any given time. When this happens, like at any other company, it is entirely outside of the control of InnPower management. All InnPower can do is begin the process for recruiting new staff to fill these vacancies.

56. By coincidence of timing, it happened that InnPower had three such vacancies at the time this Application went to oral hearing. Like any other company, InnPower has already started the recruitment process to once again fill those positions.

57. InnPower's evidence is that these three positions must be filled, in part because the work still needs to be done, and in part to address a variety of operational issues that have arisen due to the current understaffing situation including increased overtime, increased stress leaves, increased turnover, the higher costs of subcontractor work, all of which lowers worker productivity and efficiency.[23] In this context, it would be inappropriate to arbitrarily cut three specific FTE positions simply because the positions happen to be vacant at a particular point in time. The Board has sufficient evidence to know that doing so would cause serious harm to utility operations.

A.5 Other clarifications.

58. OEB Staff also sought clarity regarding whether InnPower has included an amount of \$60k in 2017 test year OM&A relating to Pension and Benefit Amounts.[24] InnPower confirms that it has not included this amount in test year OM&A. This is shown in the updated Appendix 2-KA table which was filed as a correction at the start of the oral

[23] Transcript Vol. 1 at pgs. 13-14.
[24] OEB Staff Submissions at pg. 6 and again at pg. 29.

hearing and marked as Exhibit K1.1. The 2017 OM&A amount proposed to be included in rates is $19,934.

59. However, as noted in Section A.3 above, the Board should consider the adjustment to employee pension and benefits of $60,500 that was driven directly due to the transition to IFRS when considering OM&A cost drivers that are truly extraordinary and outside a normal formulaic approach.

B. CAPITAL EXPENDITURES (ISSUE 1.1)

B.1 The New Administrative Building

60. A key component of the revenue deficiency in this Application relates to an increase in rate base of approximately $9,964,561, and an increase in property taxes and other OM&A expenses of $138,714,[25] all directly attributable to the new administrative building the need and prudence of which was previously approved by the Board in its EB-2014-0086 Decision and Order.

61. The rate increase associated with this Application will, in-part, be offset by a rate reduction associated with the ending of the ICM rate rider that was approved in the EB-2014-0086 decision.

62. At paragraphs 33-51 of its Argument-in-Chief InnPower detailed its interpretation of the settlement approved by the OEB in its EB-2014-0086, particularly as it relates to the treatment of the excess office space known as the leasing space. Both SEC[26] and VECC[27] agree that InnPower's proposed approach with regards to the leasing space is reasonable.

63. It is noteworthy that both VECC and SEC were party to the original settlement proposal. The only other party to the original settlement, Energy Probe, did not intervene in this Application.

64. In this context, OEB Staff argue that "the issue regarding the cost of the new

[25] Undertaking JT1.8.
[26] SEC submissions at para. 1.3.5.
[27] VECC submissions at para. 28.

administration building should not perpetuate into the future."[28] Based on this, OEB Staff argue that InnPower should be precluded from making a future request to recover the incremental cost of $2.35 million related to the leasing space or the approximately $245,000 of additional costs associated with the new building – and the value of the building to be included in rate base should be fixed at $10.9 million and not be revisited in any future rate applications.[29] OEB staff further argue that InnPower should include approximately $33,000 of leasing revenue as a revenue offset "in order to comply with previous OEB direction."[30]

65. InnPower disagrees with OEB Staff's proposal. It violates nearly a century of law as it relates to utility rate regulation. OEB Staff's proposal is not in the public interest.

66. The traditional test for capital investments of this nature may be traced back to a 1923 decision of the Supreme Court of the United States, which held that utilities should receive deference in seeking to recover "investments which, under ordinary circumstances, would be deemed reasonable."[31]

67. In the decades that followed, both American and Canadian utility regulators tasked with reviewing utility costs generally employed one of two standards: the "used and useful" test or the "prudent investment" test.[32]

68. The Supreme Court in OPG described the used and useful test as follows:

> "The used and useful test allowed utilities to earn returns only on those investments that were actually used and useful to the utility's operations, on the principle that ratepayers should not be compelled to pay for investments that do not benefit them."[33]

69. InnPower's proposal in respect of the leasing space, as outlined in Argument-in-Chief, can

[28] OEB Staff submissions at pg. 17.
[29] Ibid. at pg. 5, bullet 3.
[30] Ibid. at pg. 6, bullet 7.
[31] *State of Missouri ex rel. Southwestern Bell Telephone Co v Public Service Commission of Missouri*, 262 U.S. 276 (1923), at p. 289, fn.1.
[32] *Ontario (Energy Board) v. Ontario Power Generation Inc.,* 2015 SCC 44 [*OPG*], at para 89.
[33] Ibid. at para. 90.

be understood in direct reference to the "used and useful" test. If the OEB approves the exclusion of the $33k in leasing revenues from the calculation of other revenues (as proposed by InnPower), the leasing space would no longer be considered "used and useful" in utility operations. For this reason, InnPower also proposed to remove the ratebase and OM&A costs associated with the leasing space from the calculation of rates. By doing so, InnPower ensure that ratepayers are not compelled to pay for the leasing space when they do not currently benefit from them. As previously noted, both SEC and VECC agreed that InnPower's proposal is reasonable in this regard.

70. If, on the other hand, the OEB orders that InnPower should record $33k in leasing revenues in the calculation of other revenues (as proposed by OEB Staff), then the Leasing Space would be both used and useful. Specifically, it would be used to generate leasing revenues, which in-turn help lower rates – akin to any other excess space leased out by a utility. In this circumstance, since the leasing space would meet the "used and useful" test, the OEB must also approve the ratebase of $2.35 million and the OM&A costs associated with the leasing space unless it is demonstrated that the proposed costs are in some way imprudent.

71. What is surprising about OEB Staff's position on the administrative building is that OEB Staff does not support its recommended permanent reductions to ratebase with any allegations that the money spent by InnPower on the administrative building was in any way imprudent. Indeed, no Party has made any allegations of imprudence regarding the building.

72. This is because InnPower provided 317 pages of comprehensive and detailed evidence in support of the prudence of its expenditures on the new administrative building in response to the SEC Preliminary Interrogatories.[34] This evidence of prudence included, without limitation, evaluating numerous options before settling on the most cost-effective option, which permitted the sharing of numerous material common expenses with the Town of Innisfil,[35] the running of a competitive tendering process before selecting the lowest cost

[34] InnPower Responses to SEC Preliminary Interrogatories dated August 3, 2017.
[35] See, for example, the Cost Sharing Site Servicing Agreement filed at Ref 1(f) to the SEC Preliminary

bidders (including BWK Construction), entering into a fixed price turn-key EPC Contract with that vendor,[36] and closely managing the change process so as to control the number of change orders and scrutinize any cost increases.[37]

73. The prudent investment test is, by contrast, a more flexible test. The intent of this test is to ease the potentially onerous burden on utilities, who may be disinclined to make innovative investments if the costs of failed investments could not be recouped: "the prudent investment test followed Justice Brandeis's preferred approach by allowing for recovery of costs provided they were not imprudent based on what was known at the time the investment or expense was incurred."[38]

74. OEB Staff ignore this legal threshold test in their analysis. In *Enbridge Gas Distribution Inc. v. Ontario Energy Board*, the Ontario Court of Appeal adopted the formulation of the Ontario Energy Board for the prudent investor test framework:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. [para. 10][39]

75. In this context, OEB Staff failed to challenge the prudence of InnPower's spending on any reasonable ground. It is worth considering the reasons given by OEB Staff for the

Interrogatories. The effect of this cost sharing agreement significantly reduced costs paid by ratepayers.

[36] A description of the process is found in response to SEC Preliminary Interrogatory 1(b). The EPC Contract is attached as Ref 1(b) to the SEC Preliminary Interrogatories.

[37] Ibid. at pg. 8 of the SEC Preliminary Interrogatories.

[38] OPG at para 91.

[39] *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)* (2006), 210 O.A.C. 4 (Ont. C.A.), leave to appeal to S.C.C. refused, [2006] S.C.C.A. No. 208 (S.C.C.) [*Enbridge*], at p. 5; qtd in OPG at para 99.

proposed reductions in ratebase associated with the administrative building. In this regard, OEB Staff argue that:

a. "InnPower has had the opportunity in both the 2015 proceeding and this proceeding to demonstrate the prudence of this $2.35 million. However, InnPower removed the amount from its request in both the 2015 and 2017 proceedings."
b. "the extra $244,506 of costs were not clearly articulated in InnPower's evidence. It was only when InnPower was specifically asked to confirm whether it had costs related to the new building included in the 2017 test year rate base beyond the $10.9 million, that this information was highlighted to parties."

76. InnPower shall address the second argument first. Contrary to the submissions of OEB Staff, the extra $244,506 of actual costs were clearly articulated throughout all of InnPower's evidence. It is most clearly illustrated as the difference between the estimated costs in the EB-2014-0085 application of $13,246,706 and the actual costs of $13,491,210 shown in the reconciliation filed in response to SEC Preliminary Interrogatory 1(a) at page 3 in August of 2016, which is shown again below for ease of reference.

Asset	Actual Cost	Original Application EB-2016-0085	Estimated in ICM EB-2014-0086	Final Approved in ICM EB-2014-0086	Amended Application EB-2016-0085
Land	$ 1,015,496	$ 1,015,496	$ 1,015,496	$ 1,015,496	$ 1,015,496
Building	$ 11,094,469	$ 11,781,208	$ 11,781,208	$ 8,344,626	$ 8,824,429
Roof	$ 428,122	$ -	$ -	$ 754,637	$ 428,122
HVAC	$ 354,729	$ -	$ -	$ -	$ 354,729
Parking Lot	$ 354,729	$ 375,000	$ 375,000	$ 781,945	$ 354,729
Furniture & Chattels	$ 243,664	$ 75,000	$ 75,000	$ -	$ 243,664
Total	**$ 13,491,210**	**$ 13,246,704**	**$ 13,246,704**	**$ 10,896,704**	**$ 11,221,170**

77. InnPower has at all times indicated that actual costs were $13,491,210. InnPower provided detailed evidence in support of the prudence of the entire actual costs of $13,491,210 in response to the SEC Preliminary Interrogatories. This included a breakdown of actual costs by asset category, a breakdown of actual costs of the building by contractor/vendor,

an explanation of the LEED component of the costs, a detailed narrative explaining the original plan and changes to the plan including options considered and choices made, copies of all relevant third party agreements, and a detailed itemization of all change orders made under the original EPC agreement, a detailed description of how each major contract was made (competitive procurement or otherwise) and the change order process and any disputes.

78. OEB Staff did not make any reference to this evidence in their submission. The failure to consider this evidence informs their apparent surprise that actual costs were $244,506 above the forecasted amounts.

79. InnPower's management is legally entitled to a presumption of prudence.

80. No party has provided a cogent argument sufficient to rebut this presumption of prudence. Specifically, neither OEB staff nor VECC nor SEC has provided a single allegation of imprudence associated with the spending on the building, despite being equipped with hundreds of pages of evidence in support of the prudence of the expenditures on the building.

81. The mere fact that InnPower has voluntarily proposed to exclude the leasing space, and associated leasing revenues and associated OM&A costs from rates in the test year, is not sufficient rationale to rebut the presumption of prudence. As noted by the Court of Appeal, hindsight should not be used in determining prudence.

82. OEB Staff's suggestion would effect a penalty on InnPower simply for attempting to implement both the spirit and intent of the EB-2014-0086 settlement, a proposal that both SEC and VECC agree is reasonable in the circumstances. This is neither just nor reasonable.

83. Even if the OEB determines that, for some unknown reason, the presumption of prudence has been rebutted - InnPower has provided sufficient evidence to conduct a retrospective factual inquiry, and that evidence demonstrates clearly that the decisions to invest in the new building were reasonable under the circumstances that were known to the utility at

the time the decision was made.

84. The simple truth is that the costs of building in Innisfil is, due to its proximity to the GTA, higher than in other rural areas in the province of Ontario. Contractors that bid on projects in Innisfil are also bidding on projects throughout the GTA and Golden Horseshoe area. This was shown conclusively when InnPower ran a competitive tender process prior to selecting the lowest cost bidder, BWK Construction, to be the turn-key EPC contract to build the administrative building.

85. Given this, InnPower submits that there is no basis in evidence, or in any of the submissions of the parties, to deny either the $2.35 million or the $244,506 from ratebase.

B.2 Other capital expenditures

86. A second key contributor to the revenue deficiency is the approximately $10.7 million increase in ratebase driven by higher than normal investments in system access and system renewal driven by high growth in the InnPower service territory.

87. Mr. Malcolm explained the drivers of these capital costs during examination-in-chief,[40] which were driven in large part by new developments in Friday Harbour, South Barrie, Lefroy and Belle Ewart areas of the InnPower service territory. In order to service these lands, InnPower needed to build a new distribution station, upgrade the capacity of an existing distribution station, as well as revitalize and rebuild overhead pole lines and infrastructure to provide sufficient capacity to service those lands. In addition, there has been an increase in pole replacements and a catastrophic transformer failure that also contributed to the cost of system renewal investments. Finally, in a smaller way, InnPower's investment in automation SCADA systems as well as a change of its radio communication network also contributed this increase, both of which drove increased reliability directly to the benefit of customers. This is all more fully detailed in Exhibit 2, Section 2.2.1.1 in the year-over-year analysis of variances in ratebase as well as in Appendix 2-AA which shows year-over-year historical capital expenditures at the project level.

[40] Transcript Vol. 1 dated Oct. 3, 2017 at pg. 9, line 24 to pg. 10, line 13.

88. In this regard, no Party has alleged these historical capital expenditures were imprudent. The only Party that addressed this issue was SEC: "From SEC's point of view, we have not identified any material component of the sunk costs of capital assets that do not meet the traditional test of prudence. […] The Applicant appears to have built to improve its system. […] Based on the evidence in this proceeding, SEC cannot conclude that any specific past or proposed capital additions are or were imprudent."[41] InnPower submits that the presumption of prudence has not been rebutted. In any event, all of the expenditures resulted in new assets that are both used and useful - they increased the capacity and reliability of the InnPower distribution system, changes that were needed to service new customer growth that is scattered across a large rural service territory.

89. OEB Staff summarized these historical capital expenditures as well as the forecasted capital expenditures over the planning period at Table 1 of their submissions. InnPower provided a more detailed summary in response to Undertaking JT1.2, which is reproduced again below.

Table JT1.2 Historical and Forecast Capital Expenditure and System O & M

	Historical					Forecast				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Category	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	1,750	1,039	1,263	896	1,084	1,757	2,534	1,658	1,709	2,129
System Renewal	654	987	697	487	999	1,216	1,140	2,919	2,400	2,109
System Service	586	1,377	2,819	2,944	1,743	245	79	961	1,006	824
General Plant	828	1,348	253	13,250	661	1,187	1,423	897	680	706
Total	3,818	4,751	5,031	17,578	4,487	4,405	5,176	6,434	5,794	5,769
System O&M	1,761	1,787	1,814	1,805	1,986	2,246	2,245	2,246	2,246	2,246

**0 months of actual data included in 2016.*

90. In this context, both OEB Staff[42] and SEC[43] support InnPower's proposed test year capital expenditures envelope of $4.405 million. This was no doubt influenced by the compelling rationale provided at paragraphs 15-20 of InnPower's Argument-in-Chief.

91. By contrast, VECC argues that the Board is bound to use the best information it has available.[44] Based on this approach, VECC argues that the Board must eliminate from rate

[41] SEC Submissions at paras. 4.4.3-4.4.5.
[42] OEB Staff Submissions at pg. 14.
[43] SEC Submissions at 4.4.3 and 4.5.2.
[44] VECC submissions at pg. 2, para. 9.

base $490,000 in vehicle costs.[45] VECC's approach amounts to a selective reduction in rate base, while purposefully ignoring known increases in actual spending on other projects, most notably on Base 4 System Access Projects.

92. As described in its Argument-in-Chief, if the OEB would prefer to use a more up-to-date forecast of capital expenditures in the test year (for example, to reflect the fact that the delivery of the double bucket truck has been delayed), then this should be done on a comprehensive basis across the entire capital program to accurately reflect both increases and decreases in the expenditures amounts. InnPower has provided its most up-to-date forecast in Undertaking JT1.5, Table JT1.5A, in the column titled "2017 Year End Forecast-Net" which accurately reflects both reductions in some projects and increases in others. This would result in the forecasted capital for the test year increasing by more than $600k, driven in large part by a substantial increase in the actual spending on "Base 4" System Access projects, but offset somewhat by decreased spending in other categories.

B.3 Other Commentary on the InnPower Distribution System Plan

93. VECC argues that InnPower's Distribution System Plan is flawed, on the basis that "in large the data from which these assessments are made is simply plant age" and that consequently the OEB needs to guard against "garbage in, garbage out" risk.[46]

94. InnPower disagrees that the correct level of funding for System Renewal is at the average of the previous 3 years and that the ACA as provided is flawed, or in any way misleading.

95. In the previous years, the funds for System Renewal were dramatically cut. As is evidenced in the Asset Condition Assessment ("**ACA**"), this has resulted in a short fall in re-investment that has resulted in higher than normal aged assets. Therefore in order to maintain asset health it has been necessary to increase system renewal spending.

96. InnPower's initial Distribution System Plan submission envisioned a capital spend of about an average of $6.5 million however adjustments to the capital contributions in 2017 have left a projection of $4.4M. This will in turn impact System Renewal Opportunities in

[45] Ibid.
[46] VECC Submissions at paras. 10-12.

the years 2018-2021.

97. InnPower commissioned an industry leading firm (METSCO) to execute an ACA, which was signed and sealed by METSCO and attached to the Distribution System Plan. Along with assessing asset health, this report indicates that a large number of assets are significantly older than the "Typical Useful Life" ("**TUL**"). This is particularly true of poles with roughly 50% of the tested pole population exceeding TUL and most of those exceeding the "Max Useful Life" ("**Max UL**").[47] In addition, 8% of cables are also exceeding Max UL. As per the requirements of the Distribution System Code, InnPower will have pole testing completed on 100% of the poles within another year or two. In addition, condition is confirmed before poles are scheduled for replacement.

98. InnPower has also committed to the collection of data on underground cable condition, prior to executing a cable replacement or rejuvenation program. This additional testing has not yet been completed as there is an O&M cost component to this work and it is most useful to carry out in conjunction with detailed project planning.

99. InnPower accepts the ACA report and believes that it is predicting a future rate impact for System Renewal that is even greater than the proposed measures if funding for renewal is reduced.

100. In support of the credibility of the ACA report itself, METSCO submits that, in addition to being signed and sealed by a professional engineer, the processes and data input used in its creation and the general reporting of the Health Index of the Assets are consistent with industry methods. METSCO notes that it had robust data for Station Assets, and Distribution Assets. Specifically InnPower is on pace to complete 100% pole inspections within a year or two.

101. Another item with a substantial impact on the Distribution System Renewal are the underground cables. The Health Index Formulation (HIF) for cables is driven by age, type, and failure history. The existing assets have not yet experienced the failure rates of previously replaced cables and as a result the HIF inputs are using "40+ years" for the age

[47] Max UL is defined in the Kinetics Report on "Useful Life of Assets."

parameter and "0" for the failure rate parameter. Cables will be tested prior to project work, and data confidence will be high.

102. It is METSCO's opinion that the InnPower ACA indicates that Asset Renewal has not kept pace with degradation particularly in the Pole and Cable Assets.

103. OEB staff allege that "pacing and prioritization" have not been considered in InnPower's distribution system planning process.[48] OEB Staff cite no evidence to support this assertion, except by noting that "detailed project narratives" were only provided for the test year.

104. OEB Staff does not provide any guidance on what they mean by the term "detailed project narratives." The only reasonable interpretation is in reference to the requirements of Section 5.4.5.2 of the Chapter 5 Filing Requirements. The requirements stipulate detailed list of evidentiary requirements, spanning pages 19-25, for material capital projects.

105. In this context, OEB Staff fail to acknowledge that all 2017 cost of service filers only provided detailed project narratives for the test year. Nor does OEB Staff acknowledge that the same is true for the vast majority of cost of service filers for 2016 and 2015.

106. InnPower disagrees with OEB Staff's assertions regarding pacing and prioritization. OEB Staff's allegation is in direct contradiction to the evidence on the record, which demonstrate that pacing and prioritization is a fundamental part of InnPower's distribution system planning process.

107. It is not an accident that forecasted capital expenditures in the test year are less than what was actually spent in each of 2013, 2014, 2015 and 2016, and only slightly more than what was spent in 2012. It is also not an accident that the forecasted capital expenditures in the test year are less than what is forecasted to be spent in each of the years 2018-2021. This is evidence that InnPower is clearly pacing its planned capital expenditures in a manner that accounts for customer feedback and preferences and impacts on distribution rates.

[48] OEB Staff Submission at pg. 21, and at pg. 5, para 4.

108. It is also not an accident that, because of the forecasted increase in System Access spending forecasted for 2017 and 2018, InnPower has deferred a much needed increase in System Renewal spending to 2019 and beyond. While higher spending in the renewal of pole assets is urgently needed based on the METSCO Distribution Assets Condition Assessments attached to the DSP, InnPower is pacing its renewal to only do what is absolutely required in the test year and to defer the bulk of any increases in renewal spending until after the System Access work slows down.

109. InnPower detailed its approach to pacing and prioritization in Section 4.2.3 of InnPower's Distribution System Plan. This resulted in a prioritized list of discretionary material capital projects summarized in Table 4-13 of the Distribution System Plan, some of which clearly get deferred into future years. This prioritization methodology was explored in detail by SEC with Mr. Thompson during the second day of the technical conference.[49]

110. InnPower will use the same project prioritization methodology in years 2018-2021 as was used in 2017 to assess discretionary projects and will ensure that those projects with the highest level of risk are addressed as a priority and that pacing occurs consistent with the needs of both new growth, system renewal and service related projects.

111. The project definition, pacing and prioritization process is done at the start of the budgeting process for each year on an annual basis. It is not done one time as part of a 5-year Distribution System Plan.

112. As shown in response to Undertaking JT2.5, actual capital expenditures during the test year often vary considerably from forecast depending on what actually occurs. This variance gets worse and worse as you proceed through years 2-5 of the DSP. It is increasingly likely that any projects identified in years 2-5 will change (perhaps considerably) before they are implemented (if they are implemented at all).

113. This is why it has become industry practice that in a forward test-year cost of service application, that Applicants are not expected to produce detailed project narratives for years outside of the test-year. This industry practice arose immediately after the creation

[49] Technical Conference Transcript Vol. 2 dated Sept. 13, 2017 at pg. 67, line 17 to pg. 76, line 25.

of the Chapter 5 Filing Requirements, when BLG requested guidance from OEB Staff on the OEB's expectations in this regard. Following discussions, OEB Staff confirmed that cost of service filers are not expected to prepare detailed project narratives for years outside of the test-year. This is why InnPower's Application was found to be "complete" by OEB Staff following a detailed completeness review against the Chapter 2 and Chapter 5 Filing Requirements.

114. In this context it is worth noting that the OEB is not being asked to approve costs beyond the test year. Nor is the OEB being asked to approve the five-year Distribution System Plan. Consequently, detailed project narratives for years 2-5 are of limited probative value to the matters at issue in this forward test-year cost of service Application.

115. Finally, in response to OEB Staff's question about InnPower's Custom IR Application, it was rejected as being incomplete. It is not an active application. The evidentiary requirements of a Custom IR Application should not be imported into this Application. InnPower underwent a change of management and chose to shelve the Custom IR Application and move forward with a new management philosophy and a new rate application. Old project narratives, prepared under an old management philosophy, are not relevant to this Application. They have neither been reviewed or approved by the new InnPower management team.

116. Finally, InnPower is willing to assess the use of non-destructive cable testing as part of its project prioritization process. Testing of this sort has not been directly addressed thus far, since the relevant underground projects are still a couple years into the future. However, InnPower acknowledges that it is a useful tool to understand the condition of the cables and is a useful exercise to undertake prior to a major underground project. This is similar to InnPower's overall commitment to use any other practical tools at its disposal to manage project prioritization and pacing.

B.4 Future ICM Applications

117. OEB Staff recommend that the OEB consider emphasizing in its decision on the current application that any ICM that InnPower may seek in the future will require rigorous

evidence as to why sufficient information was not available at the time of this Application.[50]

118. OEB Staff's submission are directly contrary to the OEB's policy on the availability of funding options for capital investments, inclusive of the ICM and the ACM. Specifically, the Report of the Board in EB-2014-0219 confirmed at Section 5 that:

> "While the Board has advanced the opportunity for distributors to apply for early identification of projects during the cost of service application to be included for ACM treatment during the subsequent Price Cap IR terms, the Board will retain the availability of new ICM requests in each of the IR years, with the same scope as exists with the current approach. **ICM projects will not be limited to those that are unanticipated**, but will be subject to the revised criteria discussed in this paper such as the elimination of the non-discretionary requirement and the means test."

119. The Report of the Board further notes at Section 4 that:

> "The Board will retain an incremental capital module (or "ICM") for the IR years for projects not included in the DSP filed with the most recent cost of service application, **and** for projects that were included in the DSP but which did not contain sufficient information at the time of the cost of service application to address need and prudence."

120. OEB Staff have cited no evidence in support of their argument that InnPower should be treated differently from all other distributors in Ontario. In the above noted Report of the Board, the OEB clearly turned their minds to and rejected the proposition cited by OEB Staff that a distributor should be limited to when considering future ICM applications simply because the ACM was added as an option.

121. OEB Staff's suggestion is particularly worrying given the evidence that InnPower's entire senior management team is new to their respective roles. Mr. Malcolm only started his position in August of 2016, and the evidence is that he intends to undergo a rigorous long-term business planning process following the completion of this Application.

122. It is not clear why OEB Staff believe it would be in the public interest to unilaterally change the requirements for an ICM in a manner that would only serve to potentially

[50] OEB Staff submissions at pg. 15.

undermine this new management team's ability to best manage a very high growth utility while maximizing value for customers.

C. OTHER REVENUES (Issue 2.1)

C.1 Affiliate services

123. InnPower has at all times agreed that it should price the services it provides to its affiliate, InnServices, in accordance with the principles outlined in the OEB's *Affiliate Relationship Code*.

124. In this context, SEC argues that when costing for the Financial Services[51] and Water and Wastewater Billing services[52] provided by InnPower to its affiliate, InnServices, InnPower has not accounted for what are generally referred to as "overhead costs" such as costs related to insurance, information systems, building, office supplies, etc.

125. InnPower agrees that the costs it charges to its affiliate should include a proper allocation of overhead costs. InnPower appreciates SEC's efforts to bring this to our attention. InnPower believes that a proper allocation of all costs, including overhead costs, in accordance with the *Affiliate Relationship Code* is appropriate.

126. That said, InnPower does not agree with the very rough calculations prepared by SEC to attempt to account for these amounts. Such an approach may under-estimate the overhead costs, such as in the case of Water and Waste Water Billing, or over-estimate the overhead costs, such as in the case of Financial Services.

127. Rather than asking the Board to rely on the very rough calculations prepared by SEC, InnPower has done a more fulsome analysis below.

128. Specifically, InnPower has gone through line-by-line all General and Administrative Expenses forecasted in the test year to identify all overhead costs that are attributable to the scope of Water and Wastewater Billing Services. The result was $421,673. InnPower

[51] SEC Submissions at para. 3.2.10 – 3.2.13.
[52] SEC Submissions at para 3.3.5.

then added these overhead costs to the total cost per electric bill, together with all other costs outlined in response to Undertaking JT2.3. This results in a total cost per bill of $3.41 if the costs are shared on a 50/50% basis between electric and water/wastewater billing (the same methodology as used in Undertaking JT2.3). It is worth noting that InnPower issues a total of 198,000 electric bills and 124,000 water/wastewater bills annually, thus a 50/50% is more than appropriate. As explained by Mr. Brown, currently InnPower is charging InnServices $2.40 per bill.[53] If this was increased by $1.01 per bill, for the 124,000 bills, this will result in an increase in other revenues in the test year of $125,240.

129. InnPower submits that this increase is more appropriate than the rough calculation that was proposed by SEC, as it is based on an actual analysis based on the evidence on the record in this proceeding.

130. InnPower has also gone through line-by-line all General and Administrative Expenses forecasted for the test year to identify all overhead costs that are attributable to the scope of Financial Services. The result was $705,036. InnPower attributed those overhead costs across all 45 FTEs ($16,396 per FTE), and InnPower then attributed the appropriate portion of overhead costs to the 2.5 FTEs that are involved in providing Financial Services to InnServices. This results in an increase in the total costs charged to InnServices for Financial Services of $40,990.49.

131. InnPower submits that this results in a more appropriate allocation of General and Administrative costs than the 50% assumed by SEC, given that only 2.5 of InnPower's 45 FTEs are involved in providing Financial Services to InnServices.

C.2 Leasing Revenue

132. InnPower has addressed the submissions on other revenues associated with the leasing space above together with its submissions on the administrative building, as the two issues are linked. InnPower will not reproduce those submissions again here.

[53] Transcript Vol. 1 dated Oct. 3, 2017 at pg. 43, lines 15-16.

D. LOAD FORECAST, COST ALLOCATION & RATE DESIGN (ISSUES 3.1, 3.2 & 3.3)

D.1 Load Forecast (Issue 3.1)

133. VECC has no issues with InnPower's final load forecast or its associated methodology, based on actuals up to August 2017 and extrapolating the monthly values for the balance of the year. [54] OEB Staff agree that the customer connection forecast as updated after the technical conference result in an acceptable customer connection forecast.[55]

134. OEB Staff argue that given the changes in loss factor over time that the total loss factor of 1.0604 for secondary metered customers at less than 5000 kW be used in calculating the forecast for billed energy. [56] InnPower agrees that this proposed change is reasonable in the circumstances.

D.2 Cost Allocation (Issue 3.2)

135. VECC agrees that InnPower's proposed cost allocation methodology, and the allocations and revenue-to-cost ratios are appropriate.[57] OEB Staff also agree that InnPower's cost allocation methodology and revenue-to-cost ratios as updated after the technical conference are appropriate.[58]

D.3 Rate Design (Issue 3.3)

136. Each of OEB Staff,[59] SEC,[60] and VECC[61] argue that the fixed charge for the GS>50 rate class should be kept at the current value of $151.60.

137. The Parties submissions are based on a misreading of Section 2.8.1 of the Chapter 2 filing requirements which provides:

> "If a distributor's current fixed charge for any non-residential class is higher than

[54] VECC Submissions at para. 30.
[55] OEB Staff Submissions at pg. 35.
[56] OEB Staff submissions at pg. 34.
[57] VECC Submissions at paras. 37-40.
[58] OEB Staff Submissions at pg. 36.
[59] Ibid. at pg. 36.
[60] SEC Submissions at para. 5.1.1.
[61] VECC Submissions at paras. 42-43.

the calculated ceiling, **there is no requirement** to lower the fixed charge to the ceiling, nor are distributors expected **to raise the fixed charge further above the ceiling for any nonresidential class.**"

138. The Board's policy is clear. There is no requirement to raise the fixed charge further above the ceiling for any nonresidential class.

139. This is not the same thing as saying "where the existing charge is already above the ceiling, it may not be increased."[62] The Parties are unable to cite a source for this purported Board policy aside from the above noted Filing Requirements. However, as noted above, the wording of the Board's policy is clear – and it does not stand for what the Parties imply it does.

140. The Parties' submissions are not consistent with the Board's practice as it relates to rate design, as detailed in the 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. The Parties ignored each of these cases, although they were clearly cited by InnPower in its Argument-in-Chief.

141. The Board's EB-2014-0002 Decision and Order dated Dec. 11, 2014 is analogous to the facts in this Application. The Board summarized the facts in its decision:

> *"Horizon is proposing to maintain the current fixed/variable split in its rate design for each class. In doing so, some fixed charges are moving further above the ceiling set out in the Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667.*
>
> *EP, SEC and VECC argued that if the fixed charges moved further above the top of the range it would be contrary to current Board policy. EP pointed out that the impact of the increase is felt disproportionately by small customers.*
>
> *Board staff submitted that the Board's current policy direction is to move towards increased fixed charges. Board Staff cited section 2.11.2 of Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rates Applications (the Filing Requirements) which states:*
>
> > *On April 3, 2014, the Board released its Draft Report on Rate Design for Electricity Distributors (EB-2012-0410) which proposed implementing a fixed monthly charge for distribution service. While the policy consultation is still ongoing, distributors can propose a fixed monthly charge within their applications based on the proposed policy options as applicable, for the Board's consideration. In proposing a fixed monthly service charge to*

[62] OEB Staff submissions at pg. 36.

> *recover distribution service costs, the distributor must provide an explanation of the method used to design the fixed charge."*[63]

142. The Board then went on to explain its rational for approving Horizon's proposal:

> *"The Board accepts Horizon's proposal. While the Board's current policy direction is to move toward an increased fixed charge, this consideration was not the sole basis upon which the Board reached its Decision. The Settlement Agreement contains a re-opener provision which would address any policy change related to an increased fixed charge.*
>
> *A fixed/variable split above the ceiling was approved in Horizon's last cost of service proceeding. In this application, Horizon has maintained the fixed/variable split."*[64]

143. In this context, a fixed/variable split above the ceiling was approved in InnPower's last cost of service proceeding. InnPower proposes to maintain the same fixed/variable split. If the Board reviews the 2013 InnPower settlement agreement, this is the methodology that was agreed to by the parties and approved by the Board in the last cost of service proceeding.[65]

144. In this context, if the Board reduces the fixed cost for the GS>50kW class to $151.60, this would reduce fixed component of the fix/variable split from 22.95% fixed to 15.5% fixed. This change is in the wrong direction, given that the vast majority of distributor cost drivers are fixed. It appears to contradict the Board's general policy with regards to the fixed cost drivers associated with providing distribution services. InnPower submits that this is not in the public interest.

E. RTSR and LV Rates (ISSUE 3.4)

145. OEB Staff agrees that the RTSR model as updated following the technical conference is appropriate.[66] VECC and SEC made no submissions in this regard.

146. OEB Staff further note that the draft Rate Order should be updated to reflect any updates to the Uniform Transmission Rates, if available at that time.[67] InnPower agrees.

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[63] OEB Decision and Order dated Dec. 11, 2014 in EB-2014-0002 at pg. 8.
[6464] Ibid. at pg. 9.
[65] OEB Decision and Order dated April 25, 2013 in EB-2012-0139, Appendix A, at p. 32.
[66] OEB Staff Submissions at pg. 36.
[67] Ibid.

147. InnPower's proposed Low Voltage Rates are set out in Exhibit 8, Section 2.8.7 of the Application. No Party raised any concerns with InnPower's proposed Low Voltage Rates. InnPower submits that its proposed Low Voltage service rates are appropriate.

F. ACCOUNTING (ISSUES 4.1 & 4.1)

F.1 Accounting Changes (Issue 4.1)

148. VECC is satisfied that InnPower's application meets the criteria on this issue.[68] No other Party raised any concerns with regards to this issue in their submissions. InnPower submits that all changes in accounting standards, policies, estimates and adjustments have been properly identified and recorded and the rate-making treatment of each of these impacts are appropriate.

F.2 Deferral and Variance Account Balances (Issue 4.2)

149. OEB Staff requested that InnPower explain and rectify a discrepancy between the rate rider calculation for DVA account balances excluding GA (accounts 1550, 1551, 1584, 1586 and 1595) with the total balances for these accounts in the DVA Continuity Schedule.[69]

150. In the OEB's submission Board staff identified a discrepancy between the DVA account balances for Accounts 1550,1551,1584, 1586 and 1595 between the DVA Continuity Schedule (Tab 2 of the 2017 DVA model) and the Allocation of DVA balances (Tab 5). The following balances are presented:
DVA Continuity (Tab 2) - $781,283
Allocation of Balances (Tab 5) - $786,245
Difference - $4,962

151. InnPower has reviewed the DVA model very thoroughly and has discovered macro issues within the Allocation of Balances Tab 5:

- Column F, and Column G, Line 6 which should allocate the balance of -$5,532 for Account 1551 to the Residential and General Service <50 rate classes.

[68] VECC Submissions at para. 45.
[69] OEB Staff submissions at pg. 39.

- Column D Line 16 Account 1595 (2014) has a total amount of -$13,803, however it has only allocated -13,762 for a difference of -$41.00
- Column D Line 17 Account 1595 (2015) has a total amount of $203,730, however it has only allocated a balance of $203,119 for a difference of $ 611.00
- The sum of the 3 found discrepancies total **-$4,962**, thus the difference between the 2 tabs in the DVA model.

152. InnPower made multiple attempts to correct the cells/columns referenced however although the file would "save" once re-opened the changes were not saved. InnPower will work with Board staff to have the model corrected and filed with all the final models.

153. InnPower is in agreement that the correct amount to be utilized for the Rate Rider calculations is $781,283.

154. InnPower confirms that it is not proposing any new DVAs. The wording used in the Argument-in-Chief was paraphrasing the wording of issue number 4.2. InnPower continues to be of the view that its decision not to request any new DVAs is appropriate.

155. Subject to these clarifications, OEB Staff[70] and VECC[71] are supportive of InnPower's request for disposition of its December 31, 2015 account balances for all accounts except for accounts 1588 and 1589.

G. SPECIFIC SERVICE CHARGES (ISSUE 5.1)

156. Excluding pole attachment and microFIT charges, OEB Staff had no issues with InnPower's proposed changes to its specific service charges.

157. In this context, VECC does not raise specific concerns with the proposed specific service charge. Rather, VECC raises a number of concerns around InnPower's practices around disconnection notices, electricity disconnection for non-payment, late payments, and fees charged to customers related to the foregoing.[72]

158. InnPower submits that its practices are in strict compliance with the OEB's Distribution System Code as it relates to its billing, collections, disconnection notices, electricity disconnection for non-payment, late payments and fees related to the foregoing.

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[70] Ibid.
[71] VECC Submissions at para. 46.
[72] VECC Submissions at para. 47-60.

159. In addition, InnPower has benchmarked its practices against its peer LDCs, and has satisfied itself that its practices are very similar to the practices of a large number of other Ontario distributors. VECC has done no similar benchmarking.

160. What VECC appears to ignore is that between the date the bill is issued, the receipt of a reminder call and the sending of a disconnection notice – if the customer at any time contacts InnPower and expresses financial hardship or an inability to pay – the customer has the option to enter into a payment arrangement and no disconnection notice will be sent.

161. The only customers that receive a disconnection notice are those that have ignored the original bill, allowed the due date to pass, and completely ignored the reminder call.

162. It is worth noting that on Nov. 2, 2017 the OEB has issued a Decision and Order amending the licences of all Ontario electricity distributors to ban the disconnection of residential consumers from November 15 through April 30, and to require that disconnected homes be reconnected at no charge. The OEB indicated at that time that it continues to consult on disconnection practices as part of its customer service rules review. If the Board wishes to change its policy with regards to billing practices to account for the recent mandatory transition to monthly billing in consideration of VECC's concerns, this should be done on a province wide basis as part of this broader review. The concern VECC raises is in no way specific to InnPower. It applies to every other distributor in Ontario.

H. EFFECTIVE DATE (ISSUE 5.2)

163. OEB Staff argues that an effective date of July 1 2017 is not appropriate, and submits that October 1, 2017 would be a preferable date. OEB Staff argue that the changes which arose – specifically after the community day - were foreseeable and thus avoidable.[73]

164. InnPower respectfully disagrees. The March 9, 2017 OEB community day was held just one week after the Government of Ontario announced a 25% Fair Hydro Plan reduction of electricity bills.[74] Customers were promised by Premier Kathleen Wynne that their rates

[73] OEB Staff Submission at p. 4
[74] https://news.ontario.ca/opo/en/2017/03/households-and-small-businesses-across-ontario-to-benefit-from-lower-hydro-bills.html

would go down by 25%, then 7 days later the OEB held a public consultation to discuss how rates were proposed to go up for InnPower residents. InnPower management could not be expected to anticipate the announcement of such a major change to electricity pricing policy - seven (7) days before the OEB community day meetings. Both Mr. Shepherd and Mr. Malcolm acknowledge the confusion among customers about the relationship between the rate application and this extraordinary Provincial announcement, and both also remember that many customers were upset with various other aspects of the electricity industry which fall entirely outside of the control of InnPower management.[75]

165. InnPower submits that its requested July 1, 2017 effective date remains both just and reasonable in the circumstances.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 13TH DAY OF NOVEMBER, 2017

BORDEN LADNER GERVAIS LLP

Per:

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John A.D. Vellone

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[75] Transcript Vol. 1 at pg. 53, line 14 to pg. 54, line 22.