EXHIBIT 2: RATE BASE AND CAPITAL

2024 Cost of Service

InnPower Corporation
EB-2023-0033

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OEB Chapter 2 Appendices Mapped to InnPower COS Application

OEB Filing Requirements Mapping Exhibit 2			
OEB Chapter 2 Filing Requirements: Heading/Sub-Heading		**InnPower Corporation Application: Heading/Sub-Heading**	
2.2	**Exhibit 2: Rate Base and Capital**	**2.0**	**Exhibit 2: Rate Base and Capital**
2.2.1	Rate Base	2.1.1	Rate Base Overview
2.2.2	Fixed Asset Continuity Schedule	2.1.2 2.2.1 2.5.1 2.5.2	Rate Base Variance Analysis Property, Plant and Equipment Capital Expenditures and In-Service Additions Capital Expenditure Variance Analysis
2.2.4	Depreciation, Amortization and Depletion	2.3.1	Depreciation and Amortization
2.2.5	Allowance for Working Capital	2.4.1	Allowance for Working Capital
2.2.6	Distribution System Plan	2.5.3	Distribution System Plan
2.2.7	Policy Options for the Funding of Capital	2.5.7	Advanced Capital Module
2.2.8	Addition of Previously Approved ACM and ICM Project Assets to Rate Base	N/A	N/A
2.2.9	Capitalization	2.5.4 2.5.5	Capitalization Policy Capitalization of Overhead
2.2.10	Costs of Eligible Investments for the Connection of Qualifying Generation Facilities	N/A	N/A

2-1-1 RATE BASE OVERVIEW

1. INTRODUCTION

This Schedule provides an overview of InnPower's 2024 Distribution Rate Base. In accordance with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications – Cost of Service dated December 15, 2022, the Rate Base used to determine the Revenue Requirement for the Test Year should be presented.

This Exhibit also provides information on InnPower's Rate Base from 2017 approved to 2024 Test Year, including information on forecasted net fixed assets, calculated on a mid-year average basis, along with working capital allowance ("WCA"). Net fixed assets are gross assets in-service minus accumulated amortization and contributed capital. The capital expenditure plan for 2024 is outlined in Exhibit 2-5-1: Capital Expenditure and In-Service Additions Summary and detailed in InnPower's Distribution System Plan (filed as Exhibit 2-5-3). Information on InnPower's Working Capital can be found in Exhibit 2-4-1: Allowance for Working Capital.

InnPower's Rate Base is determined by taking the average of the asset balances at the beginning and the end of the year, plus an allowance for working capital (the sum of cost of power and controllable expenses multiplied by 7.5%). The use of the 7.5% rate is consistent with the OEB's Filing Requirements issued on June 3, 2015.

Note that the gross fixed assets and accumulated depreciation balances used in InnPower's Rate Base calculation correspond directly to the Fixed Asset Continuity Schedules that can be found in Appendix 2-2-1 (A) and within this Exhibit.

InnPower's 2024 Rate Base used in developing the detailed rates is proposed at $76,786,731.

2. PREVIOUS DECISION

In its Decision in EB-2016-0085 the OEB stated:

> "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."[1]

InnPower complied with this direction and the Rate Base shown in this application incorporates the directed changes.

3. RATE BASE

A summary of InnPower's Rate Base from 2017 to 2024 is shown in Table 2-1 below.

[1] Ontario Energy Board, *Decision and Order for InnPower Corporation,* EB-2016-0085 (March 8, 2016), page 11.

Table 2-1: Summary of Rate Base 2017 to 2024 ($'000s)

	Approved	Historical Period / Actual						Bridge	Test
	2017	2017	2018	2019	2020	2021	2022	2023	2024
Opening Gross Assets		54,657	57,791	61,797	64,592	69,293	75,714	79,747	91,707
Closing Gross Assets		57,791	61,797	64,592	69,293	75,714	79,747	91,707	100,762
Average Gross Assets	**56,765**	**56,224**	**59,794**	**63,194**	**66,942**	**72,503**	**77,730**	**85,727**	**96,234**
Opening Accumulated Depreciation		5,334	7,156	9,208	11,302	13,488	15,803	18,311	21,014
Closing Accumulated Depreciation		7,156	9,208	11,302	13,488	15,803	18,311	21,014	23,899
Average Accumulated Depreciation	**6,495**	**6,245**	**8,182**	**10,255**	**12,395**	**14,645**	**17,057**	**19,663**	**22,457**
Opening Net Book Value		49,323	50,636	52,589	53,290	55,805	59,911	61,436	70,693
Closing Net Book Value		50,636	52,589	53,290	55,805	59,911	61,436	70,693	76,863
Average Net Book Value	**50,271**	**49,979**	**51,612**	**52,939**	**54,547**	**57,858**	**60,673**	**66,064**	**73,778**
Working Capital Allowance	2,314	2,725	2,683	2,795	3,499	3,112	3,173	3,736	3,009
TOTAL	52,585	52,704	54,295	55,735	58,046	60,970	63,846	69,800	76,787

1 **Table 2-2: Rate Base 2017 Approved versus 2024 Test Year ($'000s)**

	Approved 2017	Test Year 2024	Change 2017 to 2024
Opening Gross Assets		91,707	
Closing Gross Assets		100,762	
Average Gross Assets	**56,765**	**96,234**	**39,469**
Opening Accumulated Depreciation		21,014	
Closing Accumulated Depreciation		23,899	
Average Accumulated Depreciation	**6,495**	**22,457**	**15,962**
Opening Net Book Value		70,693	
Closing Net Book Value		76,863	
Average Net Book Value	**50,271**	**73,778**	**23,507**
Working Capital Allowance	2,314	3,009	695
TOTAL	52,585	76,787	24,202

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2-1-2 RATE BASE VARIANCE ANALYSIS

1. INTRODUCTION

This Schedule provides an overview of InnPower's Distribution Rate Base and a discussion of year-over-year variances. In accordance with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications, the Rate Base used to determine the Revenue Requirement for the Test Year should be presented. This Schedule provides yearly information on InnPower's Rate Base, including information on forecast net fixed assets, calculated on a mid-year average basis, along with working capital allowance ("WCA"). Net fixed assets are gross assets in service minus accumulated amortization and contributed capital.

In this application, InnPower's capital expenditures and in-service additions are different values. Capital expenditures are cash flows associated with a capital project in a given year, while in–service additions are the capitalized value of completed capital projects that have been energized and meet the regulatory criteria of *"used and useful"*. A large percentage of InnPower's capital expenditures in a particular year are placed in service in that same year.

The capital expenditure plan for the period 2017 to 2024 is outlined in Exhibit 2-5-1: Capital Expenditure and In-Service Additions Summary. Details associated with this plan can be found in InnPower's Distribution System Plan (filed as Exhibit 2-5-3). Information on InnPower's Working Capital can be found in Exhibit 2-4-1: Allowance for Working Capital.

The year-over-year increase in net fixed assets outlined in the tables below is primarily explained by changes in the year-over-year capital expenditures which are detailed in Exhibit 2-5-2 Capital Expenditure Variance Analysis.

InnPower's Rate Base from 2017 to 2024 is shown in Table 2-3 below.

Table 2-3: Summary of Rate Base 2017 to 2024 ($'000s)

	Approved	Historical Period / Actual						Bridge	Test
	2017	2017	2018	2019	2020	2021	2022	2023	2024
Opening Gross Assets		54,657	57,791	61,797	64,592	69,293	75,714	79,747	91,707
Closing Gross Assets		57,791	61,797	64,592	69,293	75,714	79,747	91,707	100,762
Average Gross Assets	**56,765**	**56,224**	**59,794**	**63,194**	**66,942**	**72,503**	**77,730**	**85,727**	**96,234**
Opening Accumulated Depreciation		5,334	7,156	9,208	11,302	13,488	15,803	18,311	21,014
Closing Accumulated Depreciation		7,156	9,208	11,302	13,488	15,803	18,311	21,014	23,899
Average Accumulated Depreciation	**6,495**	**6,245**	**8,182**	**10,255**	**12,395**	**14,645**	**17,057**	**19,663**	**22,457**
Opening Net Book Value		49,323	50,636	52,589	53,290	55,805	59,911	61,436	70,693
Closing Net Book Value		50,636	52,589	53,290	55,805	59,911	61,436	70,693	76,863
Average Net Book Value	**50,271**	**49,979**	**51,612**	**52,939**	**54,547**	**57,858**	**60,673**	**66,064**	**73,778**
Working Capital Allowance	2,314	2,725	2,683	2,795	3,499	3,112	3,173	3,736	3,009
TOTAL	52,585	52,704	54,295	55,735	58,046	60,970	63,846	69,800	76,787

2. RATE BASE VARIANCE ANALYSIS

Table 2-4 below shows the variance between the OEB approved Rate Base amount and Test Year Rate Base.

2017 Approved to 2024 Test Year (+$24.2M)

Table 2-4: 2024 Test Year versus 2017 OEB Approved ($'000s)

	Approved 2017	Test Year 2024	Change 2017 to 2024
Opening Gross Assets		91,707	
Closing Gross Assets		100,762	
Average Gross Assets	**56,765**	**96,234**	**39,469**
Opening Accumulated Depreciation		21,014	
Closing Accumulated Depreciation		23,899	
Average Accumulated Depreciation	**6,495**	**22,457**	**15,962**
Opening Net Book Value		70,693	
Closing Net Book Value		76,863	
Average Net Book Value	**50,271**	**73,778**	**23,507**
Working Capital Allowance	2,314	3,009	695
TOTAL	52,585	76,787	24,202

- InnPower's Average Net Fixed Assets for 2024 are $23.5M higher than the 2017 approved level due to expenditures made to maintain the system in a safe and reliable manner, to address aging infrastructure and meet the needs of customer growth.
- InnPower's Working Capital Allowance for 2024 is $0.7M higher than the 2017 approved level due to higher levels of OM&A and Cost of Power.

2017 Actual to 2017 Approved (+$0.1M)

Table 2-5: 2017 Actual versus 2017 OEB Approved ($'000s)

	Historical Period / Actual			
	2017 Actual vs 2017 Approved			
	Approved 2017	Actual 2017	Var $	Var %
Average Gross Assets	56,765	56,224	(541)	(1%)
Average Accumulated Depreciation	6,495	6,245	(250)	(4%)
Average Net Book Value	50,271	49,979	(292)	(1%)
Working Capital Allowance	2,314	2,725	411	18%
TOTAL	52,585	52,704	119	0%

- InnPower's Actual Average Net Fixed Assets for 2017 are $0.3M lower than the 2017 approved level due to project delays.
- InnPower's Working Capital Allowance for 2017 is $0.4M higher than the 2017 approved level due to higher actual OM&A versus Approved levels.
- There were several projects deferred from 2017 to 2018, primarily road widening work at the request of the third parties.

2018 Actual to 2017 Actual (+$1.6M)

Table 2-6: 2018 Actuals versus 2017 Actuals ($'000s)

	Historical Period / Actual			
	2018 vs 2017			
	Actual 2017	Actual 2018	Var $	Var %
Average Gross Assets	56,224	59,794	3,570	6%
Average Accumulated Depreciation	6,245	8,182	1,937	31%
Average Net Book Value	49,979	51,612	1,633	3%
Working Capital Allowance	2,725	2,683	(42)	(2%)
TOTAL	52,704	54,295	1,591	3%

- InnPower's Average Net Fixed Assets for 2018 are $1.6M higher than the 2017 level due to several factors including an increase in road authority work, an increase in the station rehabilitation program and the purchase of a double bucket truck. This was partially offset by a reduction in System Renewal work.
- InnPower's Working Capital Allowance for 2018 is $0.04M lower than 2017, which is very similar to the 2017 level.

2019 Actual to 2018 Actual (+$1.4M)

Table 2-7: 2019 Actuals versus 2018 Actuals ($'000s)

	Historical Period / Actual			
	2019 vs 2018			
	Actual 2018	Actual 2019	Var $	Var %
Average Gross Assets	59,794	63,194	3,400	6%
Average Accumulated Depreciation	8,182	10,255	2,073	25%
Average Net Book Value	51,612	52,939	1,327	3%
Working Capital Allowance	2,683	2,795	112	4%
TOTAL	54,295	55,735	1,439	3%

- InnPower's Average Net Fixed Assets for 2019 are $1.3M higher than the 2018 level due to an increase in road authority work and a major station rehabilitation project. This was partially offset by a lower level of trouble calls and reduced General Plant spending.
- InnPower's Working Capital Allowance for 2019 is $0.1M higher than the 2018 level, which is very similar to the 2018 level.

2020 Actual to 2019 Actual (+$2.3M)

Table 2-8: 2020 Actuals versus 2019 Actuals ($'000s)

	Historical Period / Actual			
	2020 vs 2019			
	Actual 2019	Actual 2020	Var $	Var %
Average Gross Assets	63,194	66,942	3,748	6%
Average Accumulated Depreciation	10,255	12,395	2,140	21%
Average Net Book Value	52,939	54,547	1,608	3%
Working Capital Allowance	2,795	3,499	704	25%
TOTAL	55,735	58,046	2,311	4%

- InnPower's Average Net Fixed Assets for 2020 are $1.6M higher than the 2019 level due to increased volume of work associated with new developments, more capital trouble calls in 2020 versus 2019, the continuation of a major station rehabilitation project, and a radio system upgrade implemented in 2020.
- InnPower's Working Capital Allowance for 2020 is $0.7M higher than the 2019 level due to an increase in OM&A costs in 2020 versus 2019.

2021 Actual to 2020 Actual (+$2.9M)

Table 2-9: 2021 Actuals versus 2020 Actuals ($'000s)

	Historical Period / Actual			
	2021 vs 2020			
	Actual 2020	Actual 2021	Var $	Var %
Average Gross Assets	66,942	72,503	5,561	8%
Average Accumulated Depreciation	12,395	14,645	2,250	18%
Average Net Book Value	54,547	57,858	3,311	6%
Working Capital Allowance	3,499	3,112	(387)	(11%)
TOTAL	58,046	60,970	2,924	5%

- InnPower's Average Net Fixed Assets for 2021 are $3.3M higher than the 2020 level due to an increase in road authority work directed by the MTO and a purchase of a Wajax radial boom derrick (RBD) truck. This increase was partially offset by decreases in the Systems Service and System Renewal areas.
- InnPower's Working Capital Allowance for 2021 is $0.4M lower than the 2020 level due to a decrease in OM&A costs in 2021 versus 2020.

2022 Actual to 2021 Actual (+$2.9M)

Table 2-10: 2022 Actuals versus 2021 Actuals ($'000s)

	Historical Period / Actual			
	2022 vs 2021			
	Actual 2021	Actual 2022	Var $	Var %
Average Gross Assets	72,503	77,730	5,227	7%
Average Accumulated Depreciation	14,645	17,057	2,412	16%
Average Net Book Value	57,858	60,673	2,815	5%
Working Capital Allowance	3,112	3,173	61	2%
TOTAL	60,970	63,846	2,876	5%

- InnPower's Average Net Fixed Assets for 2022 are $2.8M higher than the 2021 level due to the Metrolinx Electrification Project. This increase is partially offset by lower subdivision work and the completion of major rehabilitation work in 2021.
- InnPower's Working Capital Allowance for 2022 is $0.06 higher than the 2021 level, Which is very similar to the 2021 level.

2023 Bridge to 2022 Actual (+$6M)

Table 2-11: 2023 Bridge versus 2022 Actuals ($'000s)

	Forecast Period / Planned			
	2023 vs 2022			
	Actual 2022	Bridge 2023	Var $	Var %
Average Gross Assets	77,730	85,727	7,997	10%
Average Accumulated Depreciation	17,057	19,663	2,606	15%
Average Net Book Value	60,673	66,064	5,391	9%
Working Capital Allowance	3,173	3,736	564	18%
TOTAL	63,846	69,800	5,954	9%

- InnPower's Average Net Fixed Assets for 2023 are forecast to be $5.4M higher than the 2022 level due to an increase in several large developments in Innisfil, the Barrie Area Transformer Upgrade (BATU) projects, and planned increases in the voltage regulator and animal mitigation programs.
- InnPower's Working Capital Allowance for 2023 is forecast to be $0.6M higher than the 2022 level due to a planned increase in OM&A costs in 2023 versus 2022.

2024 Test to 2023 Bridge (+$7M)

Table 2-12: 2024 Test versus 2023 Bridge ($'000s)

	Forecast Period / Planned			
	2024 vs 2023			
	Bridge 2023	Test 2024	Var $	Var %
Average Gross Assets	85,727	96,234	10,507	12%
Average Accumulated Depreciation	19,663	22,457	2,794	14%
Average Net Book Value	66,064	73,778	7,714	12%
Working Capital Allowance	3,736	3,009	(727)	(19%)
TOTAL	69,800	76,787	6,986	10%

- InnPower's Average Net Fixed Assets for 2024 are forecast to be $7.7M higher than the 2023 level due to an additional $9.12M in capital spending in 2024 (as outlined in Exhibit 2-5-3 – Distribution System Plan).
- InnPower's Working Capital Allowance for 2024 is forecast to be $0.7M lower than the 2023 level due to a decrease in the projected Cost of Power from 2023 to 2024. This decrease is offset by a slight increase in OM&A.

2-2-1 PROPERTY PLANT AND EQUIPMENT (PPE)

1. FIXED ASSET CONTINUITY

InnPower has completed Fixed Asset Continuity Schedules in accordance with Appendix 2-BA of the Filing Requirements for each of the following years: 2017 OEB Approved, 2017-2022 Actuals, 2023 Bridge Year and 2024 Test Year.

Tables 2-13 and Table 2-14 below provide a summary of those continuity schedules. Individual Schedules can be found in Appendix 2-2-1 (A).

Table 2-13: Summary of 2017 to 2024 Continuity Schedules

Summary of Continuity Schedules									
	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test
Gross Fixed Assets									
Opening Balance	57,005,180	57,006,940	57,791,140	61,797,165	64,591,832	69,292,705	75,713,779	79,746,778	91,707,063
Non-Regulated Building	(2,350,000)	(2,350,000)	0	0	0	0	0	0	0
Additions	4,404,649	3,424,696	4,066,548	2,948,391	4,714,066	7,135,674	4,451,290	11,960,286	9,120,000
Disposals	(184,030)	(290,497)	(60,524)	(153,724)	(13,192)	(714,601)	(418,291)	0	(65,451)
Closing Balance - excluding WIP	58,875,799	57,791,140	61,797,165	64,591,832	69,292,705	75,713,779	79,746,778	91,707,064	100,761,612
Average Gross Fixed Assets	**57,940,489**	**57,399,040**	**59,794,152**	**63,194,498**	**66,942,268**	**72,503,242**	**77,730,278**	**85,726,921**	**96,234,338**
Accumulated Depreciation									
Opening Balance	5,332,249	5,382,830	7,204,438	9,256,737	11,351,099	13,536,562	15,851,385	18,359,924	21,063,087
Non-Regulated Building	0	(48,822)	(48,822)	(48,822)	(48,822)	(48,822)	(48,822)	(48,822)	(48,822)
Additions	2,325,807	2,044,808	2,098,193	2,167,218	2,329,476	2,526,628	2,682,607	2,703,163	2,884,603
Disposals	(936)	(223,200)	(45,894)	(72,856)	(144,013)	(211,805)	(174,068)	0	0
Closing Balance - excluding WIP	7,657,119	7,155,616	9,207,915	11,302,277	13,487,740	15,802,563	18,311,102	21,014,265	23,898,867
Average Accumulated Depreciation	**6,494,684**	**6,269,223**	**8,206,177**	**10,279,507**	**12,419,420**	**14,669,562**	**17,081,243**	**19,687,094**	**22,480,977**
	51,218,680	**50,635,524**	**52,589,250**	**53,289,554**	**55,804,965**	**59,911,216**	**61,435,676**	**70,692,799**	**76,862,745**

Table 2-14 below reconciles the change in Accumulated Depreciation, shown above, to the annual depreciation expense (as reported in Exhibit 4-1-1 Operating Expenses Overview).

Table 2-14: Reconciliation of Change in Accumulated Depreciation to Depreciation Expense

Depreciation Expense Reconciliation									
	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test
Change in Accumulated Depreciation	2,325,807	2,044,808	2,098,193	2,167,218	2,329,476	2,526,628	2,682,607	2,703,163	2,884,603
Less: Fully Allocated Depreciation	(173,935)	(100,468)	(89,889)	(100,035)	(178,197)	(253,356)	(262,688)	(110,901)	(110,901)
Add: Non-Regulated Building	0	54,907	48,822	48,822	48,822	48,822	48,822	48,822	48,822
Less: Deferred Revenue	547,497	419,035	446,327	540,241	742,274	926,727	1,115,463	1,823,643	2,253,932
Depreciation Expense	**2,699,369**	**2,418,281**	**2,503,452**	**2,656,246**	**2,942,374**	**3,248,821**	**3,584,204**	**4,464,726**	**5,076,455**

2. GROSS ASSETS – PROPERTY PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

The OEB Filing Requirements (Section 2.2.3 Gross Assets – Property Plant and Equipment and Accumulated Depreciation) states that the distributor must provide the following information:

- Breakdown by function (transmission or high voltage plant, distribution plant, general plant, other plant) for required statements and analyses.
- Detailed breakdown by major plant account for each functionalized plant item. For the Test Year, each plant item must be accompanied by a description.

Shown below are Gross Asset and Accumulated Depreciation balances for the 2017 OEB Approved Year, 2017-2022 Historical Years, 2023 Bridge Year, and 2024 Test Year. This information is captured in the following tables:

- Table 2-15 – Gross Asset Balances 2017 to 2024
- Table 2-24 – Accumulated Depreciation Balances 2017 to 2024

The gross assets and accumulated depreciation are broken down into the following four functions:

- Distribution Plant Asset Accounts include the Uniform System of Accounts (USoA) accounts 1609, 1612, and 1805 – 1860.
- General Plant Asset Accounts include the USoA accounts 1908 – 1980 (excluding 1920), and 2005.
- Information Systems Asset Accounts include the USoA accounts 1920 and 1611 (formerly 1925).
- Contributions and grants include the USoA accounts 1995 and 2440.

For each of these functionalized plant items, a detailed breakdown by major plant account is provided. Each plant item is accompanied by a description in accordance with the Board's USoA, including the 2024 Test Year, per Filing Requirement 2.2.3.

2.1 Variance Analysis of Gross Asset Balances

InnPower's gross asset balances are projected to be $100,761,612 at the end of the 2024 Test Year, representing an increase of $41,885,883 between the 2017 OEB Approved Year and the 2024 Test Year. Significant annual variances broken down by function are discussed below.

Table 2-15: Gross Asset Balances 2017 to 2024

Gross Asset Balances 2017 to 2024											
		2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test	2017 OEB Approved to 2024 Test
Distribution Plant											
1609	Capital Contributions Paid	0	0	0	0	0	0	0	4,099,270	8,219,270	8,219,270
1612	Land Rights	394,446	394,446	394,446	397,396	397,396	397,396	397,396	397,396	397,396	2,950
1805	Land	1,049,593	1,049,593	1,049,593	1,049,593	1,049,593	1,049,593	1,049,593	1,049,593	1,049,593	(0)
1815	Transformer Station Equipment	0	0	0	0	0	0	0	1,003,404	1,003,404	1,003,404
1820	Distribution Station Equipment	7,607,832	7,167,620	7,525,876	8,998,829	12,615,481	15,035,412	15,503,386	21,975,540	25,133,540	17,525,708
1830	Poles, Towers & Fixtures	12,635,843	11,037,678	11,751,535	14,974,799	18,166,075	22,192,949	25,746,919	55,810,320	76,718,056	64,082,214
1835	OH Conductors & Devices	13,174,829	12,114,316	13,530,066	15,193,121	17,472,773	20,281,330	21,438,539	22,620,039	23,043,762	9,868,933
1840	UG Conduit	3,200,174	3,041,387	3,162,089	3,505,621	3,999,862	4,577,541	8,606,316	12,066,482	12,069,982	8,869,808
1845	UG Conductors & Devices	8,136,649	8,066,459	8,279,950	8,612,418	9,034,911	9,755,448	11,142,784	11,179,299	11,299,824	3,163,175
1850	Line Transformers	6,245,308	6,237,704	6,808,148	7,835,745	9,263,612	10,510,964	11,347,359	11,593,359	11,835,984	5,590,676
1855	Services (OH & UG)	4,383,513	4,241,798	4,822,717	5,421,145	6,001,602	6,700,257	7,252,794	7,531,794	10,404,542	6,021,029
1860	Meters	2,536,736	2,636,194	2,922,880	3,103,296	3,391,269	3,600,256	3,787,852	4,321,634	4,831,134	2,294,398
		59,364,921	**55,987,195**	**60,247,300**	**69,091,962**	**81,392,574**	**94,101,147**	**106,272,937**	**153,648,129**	**186,006,486**	**126,641,565**
General Plant											
1905	Land	1,015,496	1,015,496	1,015,496	1,015,496	1,015,496	1,015,496	1,015,496	1,015,496	1,015,496	0
1908	Buildings & Fixtures	10,103,239	10,103,239	10,299,623	10,338,536	10,408,245	10,451,980	10,595,835	10,670,835	10,745,835	642,596
1915	Office Furniture & Equipment	245,265	236,511	236,511	276,224	281,663	305,015	307,180	307,180	307,180	61,915
1930	Transportation Equipment	1,030,417	524,916	1,050,460	1,008,837	1,027,467	1,696,010	1,744,955	2,220,645	2,690,645	1,660,229
1935	Stores Equipment	140,585	135,334	135,334	135,334	135,334	135,334	135,334	135,334	135,334	(5,251)
1940	Tools, Shop & Garage Equipment	371,321	351,210	389,574	401,120	419,061	493,762	547,189	625,939	708,627	337,306
1945	Measurement & Testing Equipment	99,427	63,515	63,515	68,740	68,740	71,030	73,455	73,455	73,455	(25,972)
1980	System Supervisor Equipment	2,590,736	2,561,299	2,694,887	2,694,887	2,933,637	3,185,485	3,478,547	3,598,187	3,633,187	1,042,451
2005	Property Under Finance Lease	0	0	0	170,612	398,091	236,063	140,779	616,468	551,017	551,017
		15,596,487	**14,991,521**	**15,885,401**	**16,109,788**	**16,687,735**	**17,590,176**	**18,038,771**	**19,263,540**	**19,860,777**	**4,264,290**
Information Systems											
1611	Computer Software	1,028,027	783,404	952,109	1,066,968	1,307,075	1,459,720	1,780,841	2,107,141	2,272,141	1,244,114
1920	Computer Hardware	663,996	617,757	659,906	703,321	785,584	810,540	895,187	974,787	1,169,090	505,094
		1,692,023	**1,401,162**	**1,612,015**	**1,770,289**	**2,092,659**	**2,270,260**	**2,676,028**	**3,081,928**	**3,441,231**	**1,749,208**
Total Gross Balance before Contributed Capital		**76,653,430**	**72,379,878**	**77,744,716**	**86,972,040**	**100,172,969**	**113,961,583**	**126,987,736**	**175,993,597**	**209,308,494**	**132,655,064**
2440	Contributions & Grants	(17,777,632)	(14,588,738)	(15,947,552)	(22,380,208)	(30,880,264)	(38,247,803)	(47,240,959)	(84,286,534)	(108,546,882)	(90,769,251)
		58,875,799	**57,791,140**	**61,797,165**	**64,591,832**	**69,292,705**	**75,713,779**	**79,746,778**	**91,707,063**	**100,761,612**	**41,885,813**

2017 OEB Approved vs. 2017 Actuals

In 2017, InnPower's actual gross asset balances were lower than the 2017 OEB Approved amount by $1,084,659 or 2%.

See Table 2-16 below for the breakdown of gross asset balances by function and major plant account.

Table 2-16: 2017 OEB Approved vs. 2017 Actuals Gross Asset by USofA

	2017 OEB Approved	2017 Actual	Variance $	Variance %
Distribution Plant				
1612 Land Rights	394,446	394,446	(0)	0%
1805 Land	1,049,593	1,049,593	0	0%
Distribution Station				
1820 Equipment	7,607,832	7,167,620	440,212	6%
1830 Poles, Towers & Fixtures	12,635,843	11,037,678	1,598,165	13%
1835 OH Conductors & Devices	13,174,829	12,114,316	1,060,513	8%
1840 UG Conduit	3,200,174	3,041,387	158,787	5%
1845 UG Conductors & Devices	8,136,649	8,066,459	70,189	1%
1850 Line Transformers	6,245,308	6,237,704	7,604	0%
1855 Services (OH & UG)	4,383,513	4,241,798	141,715	3%
1860 Meters	2,536,736	2,636,194	(99,458)	-4%
	59,364,921	**55,987,195**	**3,377,726**	**6%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,103,239	10,103,239	(0)	0%
Office Furniture &				
1915 Equipment	245,265	236,511	8,755	4%
1930 Transportation Equipment	1,030,417	524,916	505,500	49%
1935 Stores Equipment	140,585	135,334	5,251	4%
Tools, Shop & Garage				
1940 Equipment	371,321	351,210	20,110	5%
Measurement & Testing				
1945 Equipment	99,427	63,515	35,912	36%
System Supervisor				
1980 Equipment	2,590,736	2,561,299	29,438	1%
	15,596,487	**14,991,521**	**604,965**	**4%**
Information Systems				
1611 Computer Software	1,028,027	783,404	244,622	24%
1920 Computer Hardware	663,996	617,757	46,239	7%
	1,692,023	**1,401,162**	**290,861**	**17%**
Total Gross Balance before	**76,653,430**	**72,379,878**	**4,273,553**	**6%**
2440 Contributions & Grants	(17,777,632)	(14,588,738)	(3,188,894)	18%
	58,875,799	**57,791,140**	**1,084,659**	**2%**

Distribution Plant:

In 2017, actual Distribution Plant assets were $3,377,726 lower than the OEB Approved amount. Variances in Distribution Plant (which includes System Access, System Renewal and System Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2017, actual General Plant assets were $604,965 lower than the OEB Approved amount and actual Information System assets were $290,861 lower than the OEB Approved amount. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2017 Actuals vs. 2018 Actuals

InnPower's actual gross asset balances increased by $4,006,024 or 7%, between the 2017 and 2018 Actuals. See Table 2-17 below for the breakdown of gross asset balances by function and major plant account.

Table 2-17: 2017 Actuals vs. 2018 Actuals Gross Asset by USofA

	2017 Actual	2018 Actual	Variance $	Variance %
Distribution Plant				
1612 Land Rights	394,446	394,446	0	0%
1805 Land	1,049,593	1,049,593	0	0%
1820 Distribution Station Equipment	7,167,620	7,525,876	(358,256)	-5%
1830 Poles, Towers & Fixtures	11,037,678	11,751,535	(713,857)	-6%
1835 OH Conductors & Devices	12,114,316	13,530,066	(1,415,750)	-12%
1840 UG Conduit	3,041,387	3,162,089	(120,702)	-4%
1845 UG Conductors & Devices	8,066,459	8,279,950	(213,491)	-3%
1850 Line Transformers	6,237,704	6,808,148	(570,444)	-9%
1855 Services (OH & UG)	4,241,798	4,822,717	(580,920)	-14%
1860 Meters	2,636,194	2,922,880	(286,686)	-11%
	55,987,195	**60,247,300**	**(4,260,105)**	**-8%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,103,239	10,299,623	(196,384)	-2%
1915 Office Furniture & Equipment	236,511	236,511	0	0%
1930 Transportation Equipment	524,916	1,050,460	(525,544)	-100%
1935 Stores Equipment	135,334	135,334	0	0%
1940 Tools, Shop & Garage Equipment	351,210	389,574	(38,364)	-11%
1945 Measurement & Testing Equipment	63,515	63,515	0	0%
1980 System Supervisor Equipment	2,561,299	2,694,887	(133,588)	-5%
	14,991,521	**15,885,401**	**(893,880)**	**-6%**
Information Systems				
1611 Computer Software	783,404	952,109	(168,705)	-22%
1920 Computer Hardware	617,757	659,906	(42,149)	-7%
	1,401,162	**1,612,015**	**(210,854)**	**-15%**
Total Gross Balance before	**72,379,878**	**77,744,716**	**(5,364,838)**	**-7%**
2440 Contributions & Grants	(14,588,738)	(15,947,552)	1,358,814	-9%
	57,791,140	**61,797,165**	**(4,006,024)**	**-7%**

Distribution Plant:

In 2018, actual Distribution Plant assets were $4,260,105 higher than the previous year. Variances in Distribution Plant (which includes System Access, System Renewal and System Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2018, actual General Plant assets were $893,880 higher than the previous year and actual Information System assets were $210,854 higher than the previous year. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2018 Actuals vs. 2019 Actuals

InnPower's actual gross asset balances increased by $2,794,667 or 5%, between the 2018 and 2019 Actuals. See Table 2-18 below for the breakdown of gross asset balances by function and major plant account.

Table 2-18: 2018 Actuals vs. 2019 Actuals Gross Asset by USofA

	2018 Actual	2019 Actual	Variance $	Variance %
Distribution Plant				
1612 Land Rights	394,446	397,396	(2,950)	-1%
1805 Land	1,049,593	1,049,593	0	0%
1820 Distribution Station Equipment	7,525,876	8,998,829	(1,472,953)	-20%
1830 Poles, Towers & Fixtures	11,751,535	14,974,799	(3,223,263)	-27%
1835 OH Conductors & Devices	13,530,066	15,193,121	(1,663,055)	-12%
1840 UG Conduit	3,162,089	3,505,621	(343,532)	-11%
1845 UG Conductors & Devices	8,279,950	8,612,418	(332,468)	-4%
1850 Line Transformers	6,808,148	7,835,745	(1,027,597)	-15%
1855 Services (OH & UG)	4,822,717	5,421,145	(598,428)	-12%
1860 Meters	2,922,880	3,103,296	(180,416)	-6%
	60,247,300	**69,091,962**	**(8,844,663)**	**-15%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,299,623	10,338,536	(38,914)	0%
1915 Office Furniture & Equipment	236,511	276,224	(39,714)	-17%
1930 Transportation Equipment	1,050,460	1,008,837	41,623	4%
1935 Stores Equipment	135,334	135,334	0	0%
1940 Tools, Shop & Garage Equipment	389,574	401,120	(11,546)	-3%
1945 Measurement & Testing Equipment	63,515	68,740	(5,225)	-8%
1980 System Supervisor Equipment	2,694,887	2,694,887	0	0%
2005 Property Under Finance Lease	0	170,612	(170,612)	0%
	15,885,401	**16,109,788**	**(224,387)**	**-1%**
Information Systems				
1611 Computer Software	952,109	1,066,968	(114,859)	-12%
1920 Computer Hardware	659,906	703,321	(43,415)	-7%
	1,612,015	**1,770,289**	**(158,274)**	**-10%**
Total Gross Balance before	**77,744,716**	**86,972,040**	**(9,227,324)**	**-12%**
2440 Contributions & Grants	(15,947,552)	(22,380,208)	6,432,656	-40%
	61,797,165	**64,591,832**	**(2,794,667)**	**-5%**

Distribution Plant:

In 2019, actual Distribution Plant assets were $8,844,663 higher than the previous year. Variances in Distribution Plant (which includes System Access, System Renewal and System Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2019, actual General Plant assets were $224,387 higher than the previous year and actual Information System assets were $158,274 higher than the previous year. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2019 Actuals vs. 2020 Actuals

InnPower's actual gross asset balances increased by $4,700,873 or 7%, between the 2019 and 2020 Actuals. See Table 2-19 below for the breakdown of gross asset balances by function and major plant account.

Table 2-19: 2019 Actuals vs. 2020 Actuals Gross Asset by USofA

	2019 Actual	2020 Actual	Variance $	Variance %
Distribution Plant				
1612 Land Rights	397,396	397,396	0	0%
1805 Land	1,049,593	1,049,593	0	0%
1820 Distribution Station Equipment	8,998,829	12,615,481	(3,616,652)	-40%
1830 Poles, Towers & Fixtures	14,974,799	18,166,075	(3,191,276)	-21%
1835 OH Conductors & Devices	15,193,121	17,472,773	(2,279,653)	-15%
1840 UG Conduit	3,505,621	3,999,862	(494,242)	-14%
1845 UG Conductors & Devices	8,612,418	9,034,911	(422,493)	-5%
1850 Line Transformers	7,835,745	9,263,612	(1,427,867)	-18%
1855 Services (OH & UG)	5,421,145	6,001,602	(580,457)	-11%
1860 Meters	3,103,296	3,391,269	(287,973)	-9%
	69,091,962	**81,392,574**	**(12,300,612)**	**-18%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,338,536	10,408,245	(69,709)	-1%
1915 Office Furniture & Equipment	276,224	281,663	(5,438)	-2%
1930 Transportation Equipment	1,008,837	1,027,467	(18,630)	-2%
1935 Stores Equipment	135,334	135,334	0	0%
1940 Tools, Shop & Garage Equipment	401,120	419,061	(17,941)	-4%
1945 Measurement & Testing Equipment	68,740	68,740	0	0%
1980 System Supervisor Equipment	2,694,887	2,933,637	(238,750)	-9%
2005 Property Under Finance Lease	170,612	398,091	(227,479)	-133%
	16,109,788	**16,687,735**	**(577,947)**	**-4%**
Information Systems				
1611 Computer Software	1,066,968	1,307,075	(240,107)	-23%
1920 Computer Hardware	703,321	785,584	(82,263)	-12%
	1,770,289	**2,092,659**	**(322,370)**	**-18%**
Total Gross Balance before	**86,972,040**	**100,172,969**	**(13,200,929)**	**-15%**
2440 Contributions & Grants	(22,380,208)	(30,880,264)	8,500,056	-38%
	64,591,832	**69,292,705**	**(4,700,873)**	**-7%**

Distribution Plant:

In 2020, actual Distribution Plant assets were $12,300,612 higher than the previous year. Variances in Distribution Plant (which includes System Access, System Renewal and System Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2020, actual General Plant assets were $577,947 higher than the previous year and actual Information System assets were $322,370 higher than the previous year. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2020 Actuals vs. 2021 Actuals

InnPower's actual gross asset balances increased by $6,421,074 or 9%, between the 2020 and 2021 Actuals. See Table 2-20 below for the breakdown of gross asset balances by function and major plant account.

Table 2-20: 2020 Actuals vs. 2021 Actuals Gross Asset by USofA

	2020 Actual	2021 Actual	Variance $	Variance %
Distribution Plant				
1612 Land Rights	397,396	397,396	0	0%
1805 Land	1,049,593	1,049,593	0	0%
1820 Distribution Station Equipment	12,615,481	15,035,412	(2,419,931)	-19%
1830 Poles, Towers & Fixtures	18,166,075	22,192,949	(4,026,874)	-22%
1835 OH Conductors & Devices	17,472,773	20,281,330	(2,808,557)	-16%
1840 UG Conduit	3,999,862	4,577,541	(577,679)	-14%
1845 UG Conductors & Devices	9,034,911	9,755,448	(720,537)	-8%
1850 Line Transformers	9,263,612	10,510,964	(1,247,352)	-13%
1855 Services (OH & UG)	6,001,602	6,700,257	(698,655)	-12%
1860 Meters	3,391,269	3,600,256	(208,987)	-6%
	81,392,574	**94,101,147**	**(12,708,573)**	**-16%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,408,245	10,451,980	(43,734)	0%
1915 Office Furniture & Equipment	281,663	305,015	(23,353)	-8%
1930 Transportation Equipment	1,027,467	1,696,010	(668,543)	-65%
1935 Stores Equipment	135,334	135,334	0	0%
1940 Tools, Shop & Garage Equipment	419,061	493,762	(74,701)	-18%
1945 Measurement & Testing Equipment	68,740	71,030	(2,290)	-3%
1980 System Supervisor Equipment	2,933,637	3,185,485	(251,848)	-9%
2005 Property Under Finance Lease	398,091	236,063	162,028	41%
	16,687,735	**17,590,176**	**(902,440)**	**-5%**
Information Systems				
1611 Computer Software	1,307,075	1,459,720	(152,645)	-12%
1920 Computer Hardware	785,584	810,540	(24,956)	-3%
	2,092,659	**2,270,260**	**(177,601)**	**-8%**
Total Gross Balance before	**100,172,969**	**113,961,583**	**(13,788,614)**	**-14%**
2440 Contributions & Grants	(30,880,264)	(38,247,803)	7,367,540	-24%
	69,292,705	**75,713,779**	**(6,421,074)**	**-9%**

Distribution Plant:

In 2021, actual Distribution Plant assets were $12,708,573 higher than the previous year. Variances in Distribution Plant (which includes System Access, System Renewal and System Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2021, actual General Plant assets were $902,440 higher than the previous year and actual Information System assets were $177,601 higher than the previous year. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2021 Actuals vs. 2022 Actuals

InnPower's actual gross asset balances increased by $4,032,998 or 5%, between the 2021 and 2022 Actuals. See Table 2-21 below for the breakdown of gross asset balances by function and major plant account.

Table 2-21: 2021 Actuals vs. 2022 Actuals Gross Asset by USofA

	2021 Actual	2022 Actual	Variance $	Variance %
Distribution Plant				
1612 Land Rights	397,396	397,396	0	0%
1805 Land	1,049,593	1,049,593	0	0%
1820 Distribution Station Equipment	15,035,412	15,503,386	(467,974)	-3%
1830 Poles, Towers & Fixtures	22,192,949	25,746,919	(3,553,970)	-16%
1835 OH Conductors & Devices	20,281,330	21,438,539	(1,157,208)	-6%
1840 UG Conduit	4,577,541	8,606,316	(4,028,775)	-88%
1845 UG Conductors & Devices	9,755,448	11,142,784	(1,387,336)	-14%
1850 Line Transformers	10,510,964	11,347,359	(836,395)	-8%
1855 Services (OH & UG)	6,700,257	7,252,794	(552,537)	-8%
1860 Meters	3,600,256	3,787,852	(187,596)	-5%
	94,101,147	**106,272,937**	**(12,171,790)**	**-13%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,451,980	10,595,835	(143,855)	-1%
1915 Office Furniture & Equipment	305,015	307,180	(2,165)	-1%
1930 Transportation Equipment	1,696,010	1,744,955	(48,945)	-3%
1935 Stores Equipment	135,334	135,334	0	0%
1940 Tools, Shop & Garage Equipment	493,762	547,189	(53,427)	-11%
1945 Measurement & Testing Equipment	71,030	73,455	(2,425)	-3%
1980 System Supervisor Equipment	3,185,485	3,478,547	(293,063)	-9%
2005 Property Under Finance Lease	236,063	140,779	95,284	40%
	17,590,176	**18,038,771**	**(448,595)**	**-3%**
Information Systems				
1611 Computer Software	1,459,720	1,780,841	(321,121)	-22%
1920 Computer Hardware	810,540	895,187	(84,647)	-10%
	2,270,260	**2,676,028**	**(405,768)**	**-18%**
Total Gross Balance before	**113,961,583**	**126,987,736**	**(13,026,154)**	**-11%**
2440 Contributions & Grants	(38,247,803)	(47,240,959)	8,993,155	-24%
	75,713,779	**79,746,778**	**(4,032,998)**	**-5%**

Distribution Plant:

In 2022, actual Distribution Plant assets were $12,171,790 higher than the previous year. Variances in Distribution Plant (which includes System Access, System Renewal and System Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2022, actual General Plant assets were $448,595 higher than the previous year and actual Information System assets were $405,768 higher than the previous year. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2022 Actuals vs. 2023 Bridge Year

InnPower's gross asset balances increased by $11,960,285 or 15%, between the 2022 actuals and the budgeted amounts for the 2023 Bridge Year. See Table 2-22 below for the breakdown of gross asset balances by function and major plant account.

Table 2-22: 2022 Actuals vs. 2023 Bridge Year Gross Asset by USofA

	2022 Actual	2023 Actual	Variance $	Variance %
Distribution Plant				
1609 Capital Contributions Paid	0	4,099,270	(4,099,270)	0%
1612 Land Rights	397,396	397,396	0	0%
1805 Land	1,049,593	1,049,593	0	0%
Transformer Station				
1815 Equipment	0	1,003,404	(1,003,404)	0%
Distribution Station				
1820 Equipment	15,503,386	21,975,540	(6,472,154)	-42%
1830 Poles, Towers & Fixtures	25,746,919	55,810,320	(30,063,401)	-117%
1835 OH Conductors & Devices	21,438,539	22,620,039	(1,181,500)	-6%
1840 UG Conduit	8,606,316	12,066,482	(3,460,166)	-40%
1845 UG Conductors & Devices	11,142,784	11,179,299	(36,515)	0%
1850 Line Transformers	11,347,359	11,593,359	(246,000)	-2%
1855 Services (OH & UG)	7,252,794	7,531,794	(279,000)	-4%
1860 Meters	3,787,852	4,321,634	(533,782)	-14%
	106,272,937	**153,648,129**	**(47,375,192)**	**-45%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,595,835	10,670,835	(75,000)	-1%
Office Furniture &				
1915 Equipment	307,180	307,180	0	0%
1930 Transportation Equipment	1,744,955	2,220,645	(475,690)	-27%
1935 Stores Equipment	135,334	135,334	0	0%
Tools, Shop & Garage				
1940 Equipment	547,189	625,939	(78,750)	-14%
Measurement & Testing				
1945 Equipment	73,455	73,455	0	0%
System Supervisor				
1980 Equipment	3,478,547	3,598,187	(119,640)	-3%
Property Under Finance				
2005 Lease	140,779	616,468	(475,689)	-338%
	18,038,771	**19,263,540**	**(1,224,769)**	**-7%**
Information Systems				
1611 Computer Software	1,780,841	2,107,141	(326,300)	-18%
1920 Computer Hardware	895,187	974,787	(79,600)	-9%
	2,676,028	**3,081,928**	**(405,900)**	**-15%**
Total Gross Balance before	**126,987,736**	**175,993,597**	**(49,005,861)**	**-39%**
2440 Contributions & Grants	(47,240,959)	(84,286,534)	37,045,575	-78%
	79,746,778	**91,707,063**	**(11,960,285)**	**-15%**

Distribution Plant:

In 2023, budgeted Distribution Plant assets were $47,375,192 higher than the previous year. Variances in Distribution Plant (which includes System Access, System Renewal and System

Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2023, budgeted General Plant assets were $1,224,769 higher than the previous year and budgeted Information System assets were $405,900 higher than the previous year. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2023 Bridge Year vs. 2024 Test Year

InnPower's gross asset balances increased by $9,054,549 or 10%, between the 2023 Bridge Year and the 2024 Test Year. See Table 2-23 below for the breakdown of gross asset balances by function and major plant account.

Table 2-23: 2023 Bridge Year vs. 2024 Test Year Gross Asset by USofA

	2023 Actual	2024 Actual	Variance $	Variance %
Distribution Plant				
1609 Capital Contributions Paid	4,099,270	8,219,270	(4,120,000)	-101%
1612 Land Rights	397,396	397,396	0	0%
1805 Land	1,049,593	1,049,593	0	0%
1815 Transformer Station Equipment	1,003,404	1,003,404	0	0%
1820 Distribution Station Equipment	21,975,540	25,133,540	(3,158,000)	-14%
1830 Poles, Towers & Fixtures	55,810,320	76,718,056	(20,907,736)	-37%
1835 OH Conductors & Devices	22,620,039	23,043,762	(423,723)	-2%
1840 UG Conduit	12,066,482	12,069,982	(3,500)	0%
1845 UG Conductors & Devices	11,179,299	11,299,824	(120,525)	-1%
1850 Line Transformers	11,593,359	11,835,984	(242,625)	-2%
1855 Services (OH & UG)	7,531,794	10,404,542	(2,872,748)	-38%
1860 Meters	4,321,634	4,831,134	(509,500)	-12%
	153,648,129	**186,006,486**	**(32,358,357)**	**-21%**
General Plant				
1905 Land	1,015,496	1,015,496	0	0%
1908 Buildings & Fixtures	10,670,835	10,745,835	(75,000)	-1%
1915 Office Furniture & Equipment	307,180	307,180	0	0%
1930 Transportation Equipment	2,220,645	2,690,645	(470,000)	-21%
1935 Stores Equipment	135,334	135,334	0	0%
1940 Tools, Shop & Garage Equipment	625,939	708,627	(82,688)	-13%
1945 Measurement & Testing Equipment	73,455	73,455	0	0%
1980 System Supervisor Equipment	3,598,187	3,633,187	(35,000)	-1%
2005 Property Under Finance Lease	616,468	551,017	65,451	11%
	19,263,540	**19,860,777**	**(597,237)**	**-3%**
Information Systems				
1611 Computer Software	2,107,141	2,272,141	(165,000)	-8%
1920 Computer Hardware	974,787	1,169,090	(194,303)	-20%
	3,081,928	**3,441,231**	**(359,303)**	**-12%**
Total Gross Balance before	**175,993,597**	**209,308,494**	**(33,314,897)**	**-19%**
2440 Contributions & Grants	(84,286,534)	(108,546,882)	24,260,348	-29%
	91,707,063	**100,761,612**	**(9,054,549)**	**-10%**

Distribution Plant:

In 2024, budgeted Distribution Plant assets were $32,358,357 higher than the previous year. Variances in Distribution Plant (which includes System Access, System Renewal and System

Service Programs) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

General Plant and Information Systems:

In 2024, budgeted General Plant assets were $597,237 higher than the previous year and budgeted Information System assets were $359,303 higher than the previous year. Variances in General Plant (which includes Information Systems) are discussed in more detail in Exhibit 2-1-2 Rate Base Variance Analysis and Exhibit 2-5-2 Capital Expenditure Variance Analysis.

2.2 Change in Accumulated Depreciation

Accumulated depreciation increased by $16,241,748 between the 2017 OEB Approved Year and the 2024 Test Year. See Table 2-24 below for the annual accumulated depreciation balances, broken down by major plant account. Fluctuations by category are as follows:

- $17,783,027 increase to accumulated depreciation on Distribution Plant assets
- $4,484,054 increase to accumulated depreciation on General Plant assets
- $1,662,928 increase to accumulated depreciation on Information Systems assets
- $7,688,261 increase (credit) to accumulated depreciation on Contributed Capital

Further discussion regarding depreciation and estimated useful lives can be found in Exhibit 2-3-1 of this Rate Application.

Table 2-24: Accumulated Depreciation Balances 2017 to 2024

Accumulated Depreciation Balances 2017 to 2024										
	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test	2017 OEB Approved to 2024 Test
Distribution Plant										
1609 Capital Contributions Paid	0	0	0	0	0	0	0	81,985	328,356	328,356
1612 Land Rights	53,241	53,241	65,940	78,669	91,462	104,219	116,977	129,735	142,493	89,252
Transformer Station										
1815 Equipment	0	0	0	0	0	0	0	12,543	37,628	37,628
Distribution Station										
1820 Equipment	807,661	614,576	871,344	1,158,902	1,530,348	2,000,799	2,517,269	3,097,271	3,666,759	2,859,098
1830 Poles, Towers & Fixtures	1,004,629	971,263	1,261,782	1,587,499	1,975,095	2,453,408	3,006,867	4,118,452	5,500,204	4,495,575
1835 OH Conductors & Devices	926,035	892,774	1,148,390	1,431,684	1,734,484	2,062,841	2,461,853	2,870,586	3,287,885	2,361,851
1840 UG Conduit	366,802	339,732	438,080	542,264	657,209	785,255	971,197	1,242,472	1,533,595	1,166,792
1845 UG Conductors & Devices	1,028,668	1,001,652	1,253,450	1,510,484	1,777,342	2,058,354	2,363,968	2,663,676	2,964,408	1,935,740
1850 Line Transformers	705,350	641,720	826,699	1,023,103	1,254,205	1,503,694	1,780,613	2,077,297	2,377,033	1,671,683
1855 Services (OH & UG)	401,296	386,082	507,288	641,748	790,325	944,607	1,122,077	1,300,841	1,500,655	1,099,359
1860 Meters	744,573	753,309	981,142	1,222,266	1,368,792	1,625,710	1,882,769	2,176,009	2,482,264	1,737,691
	6,038,254	**5,654,349**	**7,354,114**	**9,196,619**	**11,179,263**	**13,538,886**	**16,223,591**	**19,770,868**	**23,821,281**	**17,783,027**
General Plant										
1908 Buildings & Fixtures	568,995	568,995	800,350	1,034,043	1,269,600	1,505,512	1,743,308	1,980,939	2,219,403	1,650,408
Office Furniture &										
1915 Equipment	87,532	83,417	107,881	133,089	158,878	184,195	209,863	235,540	261,216	173,685
1930 Transportation Equipment	523,305	449,839	508,536	547,190	628,334	774,345	987,494	1,014,960	1,089,688	566,382
1935 Stores Equipment	40,706	39,729	53,776	67,250	80,226	92,946	105,356	117,987	130,619	89,912
Tools, Shop & Garage										
1940 Equipment	173,131	169,709	217,558	262,821	300,378	326,423	355,302	388,024	424,790	251,660
Measurement & Testing										
1945 Equipment	21,441	17,820	24,618	31,278	37,885	44,090	49,698	55,549	61,400	39,959
System Supervisor										
1980 Equipment	579,499	609,826	796,073	979,656	1,166,164	1,367,185	1,584,800	1,810,746	2,039,153	1,459,653
Property Under Finance										
2005 Lease	0	0	0	20,931	117,984	99,479	30,591	141,493	252,394	252,394
	1,994,609	**1,939,335**	**2,508,791**	**3,076,259**	**3,759,449**	**4,394,174**	**5,066,412**	**5,745,238**	**6,478,663**	**4,484,054**
Information Systems										
1611 Computer Software	751,853	615,118	744,929	871,467	1,022,234	1,194,009	1,397,759	1,618,610	1,879,283	1,127,430
1920 Computer Hardware	375,630	319,618	419,160	517,253	599,635	674,347	737,253	817,104	911,128	535,498
	1,127,482	**934,736**	**1,164,089**	**1,388,721**	**1,621,869**	**1,868,356**	**2,135,011**	**2,435,714**	**2,790,411**	**1,662,928**
Total Gross Balance before Contributed Capital	**9,160,346**	**8,528,420**	**11,026,994**	**13,661,598**	**16,560,580**	**19,801,416**	**23,425,014**	**27,951,820**	**33,090,354**	**23,930,009**
2440 Contributions & Grants	(1,503,227)	(1,372,804)	(1,819,079)	(2,359,320)	(3,072,840)	(3,998,853)	(5,113,912)	(6,937,555)	(9,191,487)	(7,688,261)
	7,657,119	**7,155,616**	**9,207,915**	**11,302,277**	**13,487,740**	**15,802,563**	**18,311,102**	**21,014,265**	**23,898,867**	**16,241,748**

2-3-1 DEPRECIATION AND AMORTIZATION

InnPower has adopted depreciation rates based on the Kinectrics Asset Depreciation Study. The rates used are presented in Appendix 2-3-1 (A) 2–BB of the Chapter 2 Appendices.

InnPower uses the half year rule for recording depreciation. InnPower use the Modified International Financial Reporting Standard (MIFRS) and separates significant components as required.

The following OEB Appendices are filed as attachments to this exhibit:

- 2-2-1 (A) OEB Appendix 2-BA – Fixed Asset Continuity Schedule
- 2-3-1 (A) OEB Appendix 2-BB – Service Life Comparison
- 2-3-1 (B) OEB Appendix 2-C – Depreciation and Amortization Schedules

2-4-1 ALLOWANCE FOR WORKING CAPITAL

1. INTRODUCTION

This Schedule provides an overview of InnPower's Allowance for Working Capital ("WCA"). In accordance with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications, the allowance for working capital calculation used to determine the deemed return on equity should be presented. This Schedule provides yearly information on InnPower's WCA, including detailed information on the Cost of Power calculation with pricing and consumption assumptions.

InnPower utilizes the OEB's default allowance for working capital ("WC"), which is set at 7.5% of the sum of the Cost of Power ("CoP") and OM&A. InnPower attests that the Cost of Power is determined by the split between Regulated Price Plan ("RPP") and non-RPP customers based on actual data, using current RPP prices and Uniform Transmission Rates ("UTR"). Table 2-25 below presents the derivation of the allowance for working capital for the historical 2017-2022, as well as the 2023 Bridge and 2024 Test Year.

Table 2-25: Working Capital Allowance (WCA) 2017 to 2024 ($'000s)

	Approve	Historical						Bridge	Test
	2017	2017	2018	2019	2020	2021	2022	2023	2024
Power Supply Expenses	$25,600	$30,238	$29,907	$31,538	$40,270	$34,915	$35,157	$42,168	$31,663
OM&A Expense	$5,254	$6,093	$5,866	$5,733	$6,383	$6,577	$7,144	$7,648	$8,457
Total Expense for WC	$30,854	$36,331	$35,773	$37,271	$40,270	$34,915	$35,157	$42,168	$31,663
Working Capital %	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total WCA	**$2,314**	**$2,725**	**$2,683**	**$2,795**	**$3,500**	**$3,112**	**$3,173**	**$3,736**	**$3,009**

2. OPERATIONS, MAINTENANCE AND ADMINISTRATION

For more details on the OM&A expenses used in Table 2-25 above, please see Exhibit 4-1-3: OM&A Summary and Cost Driver Analysis and Exhibit 4-1-4: OM&A Variance Analysis.

3. CALCULATION OF POWER SUPPLY EXPENSE

The power supply expense for the 2024 Test Year uses the forecasted monthly purchases kWh and peak kW calculated in the load forecast as described in Exhibit 3-1-1: Load Forecast. The components of InnPower's Cost of Power (COP) are summarized in Table 2-26 below and detailed in accordance with the Filing Requirements.

Table 2-26: Summary of 2024 Test Year Cost of Power Expense ($'000s)

	Test
	2024
Commodity	**$28,122**
Wholesale Market	**$1,661**
Transmission Network	**$2,476**
Transmission Connection	**$1,776**
Smart Meter Entity Charge	**$107**
Low Voltage	**$1,218**
RSVA Adjustment	**-$3,698**
Total	**$31,663**

4. COST OF POWER CALCULATIONS

Commodity

For the 2024 Test Year, the commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Prices.

The commodity price for ***Regulated Price Plan ("RPP")*** customers was determined using:

- Average RPP Supply Cost pricing of $0.0934 kWh for RPP customers.

The commodity price for ***non-RPP Class B*** customers was determined using:

- Average Hourly Energy Price (HOEP) of $0.0583 kWh for non-RPP customers.
- Average Global Adjustment (GA) of $0.0390 kWh for Class B non-RPP customers.

The commodity price for ***Class A*** customers was determined using:

- Average Hourly Energy Price (HOEP) of $0.0583 kWh for non-RPP customers.
- Average GA of $0.07277 based on InnPower's historical GA amount and Peak Demand Factor (PDF).

Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, InnPower will update the electricity prices in the forecast.

The remaining prices for Regulatory Items and UTRs used in the 2024 Test Year COP calculation are as follows:

Wholesale Market

- Wholesale Market Service (WMS) charge of $0.0041 as established in the OEB EB-2022-0269 Decision and Order.

Transmission Network and Transmission Connection

- The most recent UTR (Network and Connection) are taken from the 2024 RTSR Workform.

Smart Meter Entity Charge

- A Smart Meter Entity charge of $0.42 as established in the OEB EB-2022-0137 Decision and Order.

Low Voltage

- The most recent LV rates are taken from 2024 RTSR Workform.

RSVA Adjustment

- Rural and Remote Electricity Rate Protection (RRRRP) charge of $0.0007 as established in the OEB EB-2022-0269 Decision and Order.
- Class B Capacity Based Response charge of $0.0004 as established in the OEB EB-2022-0269 Decision and Order.

InnPower confirms the COP has been adjusted for the Ontario Electricity Rebate (11.7%).

Consumption

As noted above, InnPower used the forecasted monthly purchases (kWh and peak kW) in the load forecast as described in Exhibit 3-1-1: Load Forecast to determine 2024 Test Year COP amount.

The split between RPP and Non-RPP volumes for 2024 was determined using the 2022 actual consumption by customer type (RPP and Non-RPP) and rate class.

In accordance with the Filing Requirements, the COP for the 2024 Test Year was derived from Appendix 2-4-1 (A) 2-ZA of Chapter 2 Appendices and 2-4-1 (B) 2-ZB of Chapter 2 appendices.

2-5-1 CAPITAL EXPENDITURE AND IN-SERVICE ADDITIONS SUMMARY

1. INTRODUCTION

The capital expenditure plan summary provides an overview of InnPower's capital expenditures over the 2017 to 2024 period. The capital costs of individual projects and programs have been allocated to one of the four OEB investment categories based on the primary driver for the investment. These four categories are:

- **System access** investments are modifications to a distribution system, including asset relocations. A distributor is obligated to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.
- **System renewal** investments are replacements and/or refurbishments of system assets to extend the original service life of the assets. As a result, the distribution system is maintained to provide customers with electricity services.
- **System service** investments are modifications to a distribution system to ensure it continues to meet a distributor's operational objectives, while also addressing anticipated future electricity service requirements.
- **General plant** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system, including land and buildings, tools, and equipment, rolling stock and electronic devices and software used to support day-to-day business and operational activities.

In this application, InnPower's capital expenditures and in-service additions provide different valuations. Capital expenditures are cash flows associated with a capital project (in a given year), while in–service additions are the capitalized value of completed capital projects that have been energized and meet the regulatory criteria of *"used and useful"*. A large percentage of InnPower's capital expenditures are placed in service in the same year.

A brief summary of InnPower's Capital Expenditures and In-Service Additions for the period 2017 to 2024 follows below.

2. CAPITAL EXPENDITURE SUMMARY

Capital expenditures from 2017 to 2024, broken down by major category, are provided in Table 2-27 below.

Table 2-27: Capital Expenditures 2017 to 2024 ($'000s)

Investment Category	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test	2024 Test vs 2017 Actual	2024 Test vs 2017 Approved
System Access	1,757	1,523	2,293	5,349	7,911	9,560	7,172	25,415	23,410	21,888	21,653
System Renewal	1,216	2,553	1,908	1,526	2,069	1,812	8,460	9,994	1,429	(1,124)	213
System Service	245	21	276	2,273	2,758	2,535	1,182	11,967	7,519	7,498	7,274
General Plant	1,187	363	1,147	273	649	1,227	1,056	1,155	1,022	659	(165)
Capital Contributions	0	(1,134)	(2,522)	(6,752)	(9,028)	(10,259)	(14,787)	(37,046)	(24,260)	(23,127)	(24,260)
TOTAL	4,405	3,327	3,102	2,669	4,359	4,875	3,083	11,485	9,120	5,793	4,715

InnPower's 2024 Test Year Capital Expenditures are $9.1M as shown in Table 2-16 above. The 2024 Test Year expenditures are $5.7M greater than InnPower's 2017 approved levels and $4.7M greater than the OEB approved 2017 levels. The 2024 expenditures are a 21% reduction from the Bridge Year.

The capital projects being proposed for the Test Year will address the following key items:

- Ensuring the safety and reliability of the system
- Addressing customer expectations, and
- Responding to customer growth

Key capital projects in 2024 include:

System Access:

1. In 2024, InnPower continues to expand the main distribution system to accommodate / connect Hewitt and Salem proposed subdivisions in the South Barrie area, as well as other developments in Innisfil.
2. In 2024, InnPower will complete several road relocation projects that are forecasted to be $2.5M in gross capital.

System Renewal:

1. In accordance with the Asset Condition Assessment, InnPower plans to replace assets that are in very poor condition and / or pose a potential safety risk. These assets are, but not limited to, transformer replacements (both overhead and underground), poles, reclosers, Load Interrupted Switches (LISs), pad mount switchgears, as well as animal mitigation (which is based on the system inspection results).

System Services:

1. InnPower plans to continue to invest in automation and outage reduction projects (Normally Open Point switch installations).
2. InnPower will make capital contributions to Hydro One for the Barrie Area Transmission Upgrade (BATU) project.
3. InnPower plans to continue to advance its new Transformer Station activities to meet the long-term demand.

General Plant (Fleet):

1. Final payment for the single bucket truck purchased in 2021 will be made in 2024 to complete the delivery. The truck is expected to be delivered in 2024.
2. InnPower plans to purchase a new server to facilitate corporate growth.

A detailed discussion of InnPower's Capital Program, and a variance analysis, year by year vs. planned expenditures, is contained in the Distribution System Plan (DSP) filed as Exhibit 2-5-3.

3. IN-SERVICE ADDITION SUMMARY

InnPower's additions to its rate base in a given year come from projects that have been completed and have been placed in-service. In-service additions are fully completed capital projects that meet the regulatory criteria of being *"used and useful"*.

InnPower's Capital In-Service additions for the period 2017 to 2024 are shown below.

2-28: In-Service Additions from 2017 to 2024 ('$000s)

Investment Category	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test	2024 Test vs 2017 Actual	2024 Test vs 2017 Approved
System Access	1,757	543	736	1,304	1,866	1,754	578	1,494	2,250	1,707	493
System Renewal	1,216	2,553	1,908	1,385	1,851	1,624	2,324	1,744	1,429	(1,124)	213
System Service	245	21	276	(184)	130	2,396	503	7,091	4,419	4,398	4,174
General Plant	1,187	363	1,147	273	640	1,227	970	1,155	1,022	659	(165)
TOTAL	4,405	3,481	4,067	2,778	4,487	7,000	4,376	11,485	9,120	5,639	4,715

InnPower's in-service additions in 2024 are $9.1M. The 2024 Test Year levels are $4.7M higher than the 2017 approved level and $5.6M higher than the 2017 actual levels. The 2024 Test Year in-service additions are approximately 20% lower than those in the Bridge Year.

A detailed discussion of InnPower's Capital Program over this period is provided in its Distribution System Plan filed as Exhibit 2-5-3.

2-5-2 CAPITAL EXPENDITURE VARIANCE ANALYSIS

1. CAPITAL EXPENDITURE VARIANCE ANALYSIS

Capital expenditures from 2017 to 2024, broken down by major category, are provided in Table 2-29 below.

Table 2-29: Capital Expenditures 2017 to 2024 ($'000s)

Investment Category	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test	2024 Test vs 2017 Actual	2024 Test vs 2017 Approved
System Access	1,757	1,523	2,293	5,349	7,911	9,560	7,172	25,415	23,410	21,888	21,653
System Renewal	1,216	2,553	1,908	1,526	2,069	1,812	8,460	9,994	1,429	(1,124)	213
System Service	245	21	276	2,273	2,758	2,535	1,182	11,967	7,519	7,498	7,274
General Plant	1,187	363	1,147	273	649	1,227	1,056	1,155	1,022	659	(165)
Capital Contributions	0	(1,134)	(2,522)	(6,752)	(9,028)	(10,259)	(14,787)	(37,046)	(24,260)	(23,127)	(24,260)
TOTAL	4,405	3,327	3,102	2,669	4,359	4,875	3,083	11,485	9,120	5,793	4,715

InnPower has filed its Distribution System Plan as Exhibit 2-5-3. InnPower has also filed OEB Appendices 2-AA and 2AB as Appendix 2-5-2 (A) and Appendix 2-5-2 (B). The information shown in InnPower's Distribution System Plan and in Appendices 2-AA and 2-AB are in-service additions. As noted in Exhibit 2-5-1, capital expenditure and in-service additions are slightly different values in each year.

Although the analysis below is not required by the Filing Requirements, InnPower felt the presentation of this information would aid the readers understanding of the capital work programs and projects that InnPower has, and will be, undertaking on behalf of customers.

Variance Analysis

InnPower has classified its capital expenditures according to the four categories as outlined by the OEB. These are:

- **System access** investments are modifications to a distribution system, including asset relocations. A distributor is obligated to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.
- **System renewal** investments are replacements and/or refurbishments of system assets to extend the original service life of the assets. As a result, the distribution system is maintained to provide customers with electricity services.
- **System service** investments are modifications to a distribution system to ensure it continues to meet a distributor's operational objectives, while also addressing anticipated future electricity service requirements.
- **General plant** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system, including land and buildings, tools, and equipment, rolling stock and electronic devices and software used to support day-to-day business and operational activities.

The variance analysis provided below is presented in the four OEB categories on a Total Gross Capital Expenditure basis.

Tables 2-30 and 2-31 below show InnPower's Capital Expenditure variance analysis from 2017 to 2024.

Table 2-30: InnPower Historical Capital Expenditures Variance Analysis from 2017 to 2022 ($'000s)

Investment Category	Historical Period / Actual															
	2017	2018 vs 2017			2019 vs 2018			2020 vs 2019			2021 vs 2020			2022 vs 2021		
	Actual 2017	Actual 2018	Var $	Var %	Actual 2019	Var $	Var %	Actual 2020	Var $	Var %	Actual 2021	Var $	Var %	Actual 2022	Var $	Var %
System Access	1,523	2,293	771	51%	5,349	3,056	133%	7,911	2,562	48%	9,560	1,649	21%	7,172	(2,387)	-25%
System Renewal	2,553	1,908	(646)	-25%	1,526	(381)	-20%	2,069	543	36%	1,812	(257)	-12%	8,460	6,648	367%
System Service	21	276	255	1209%	2,273	1,997	724%	2,758	485	21%	2,535	(222)	-8%	1,182	(1,354)	-53%
General Plant	363	1,147	784	216%	273	(874)	-76%	649	376	138%	1,227	578	89%	1,056	(171)	-14%
Gross Capital Expenditures	4,460	5,624	1,164	26%	9,421	3,797	68%	13,387	3,966	42%	15,134	1,748	13%	17,870	2,736	18%
Capital Contributions	(1,134)	(2,522)	(1,388)	122%	(6,752)	(4,231)	168%	(9,028)	(2,275)	34%	(10,259)	(1,231)	14%	(14,787)	(4,528)	44%
Net Capital Expenditures	3,327	3,102	(225)	-7%	2,669	(434)	-14%	4,359	1,691	63%	4,875	516	12%	3,083	(1,792)	-37%

Table 2-31: InnPower Forecasted Capital Expenditures Variance Analysis from 2023 to 2024 ($'000s)

Investment Category	Forecast Period / Planned					
	Bridge 2023	Var from 2022 $	Test 2024	Var from 2023 $	Var $ 2024 vs 2017	Var % 2024 vs 2017
System Access	25,415	18,242	23,410	(2,004)	21,888	1437%
System Renewal	9,994	1,534	1,429	(8,565)	(1,124)	-44%
System Service	11,967	10,785	7,519	(4,448)	7,498	35579%
General Plant	1,155	99	1,022	(133)	659	181%
Gross Capital Expenditures	48,530	30,660	33,380	(15,150)	28,920	648%
Capital Contributions	(37,046)	(22,259)	(24,260)	12,785	(23,127)	2040%
Net Capital Expenditures	11,485	8,401	9,120	(2,365)	5,793	174%

2. YEAR OVER YEAR DETAILED VARIANCE ANALYSIS

The sections below will provide a detailed breakdown of variances year over year.

2018 Actual to 2017 Actual Variance

Table 2-32: Capital Expenditure Variances 2018 to 2017 Actuals ($'000s)

Investment Category	Historical Period / Actual			
	2018 vs 2017			
	Actual 2017	Actual 2018	Var $	Var %
System Access	1,523	2,293	771	51%
System Renewal	2,553	1,908	(646)	(25%)
System Service	21	276	255	1209%
General Plant	363	1,147	784	216%
Gross Capital Expenditures	4,460	5,624	1,164	26%
Capital Contributions	(1,134)	(2,522)	(1,388)	122%
Net Capital Expenditures	3,327	3,102	(225)	(7%)

System Access

2018 vs. 2017 (actual) (+$771k)

- Increase in road authority work. This work is non-discretionary driven by MTO, City of Barrie, County of Simcoe and the Town of Innisfil.
- Increase in non-discretionary projects with developers based on Offers to Connect (OTC) for subdivisions.

System Renewal

2018 vs. 2017 (actual) (-$646k)

- In 2017, there were several pole replacement programs completed.
- As a result of supply chain issues, there was a decrease in the transformer replacement program.
- The decrease in 2018 was partially offset by an increase in non-discretionary projects on trouble calls.
- The underbudgeted funds in this category were used to help fund road authority projects.

System Service

2018 vs. 2017 (actual) (+$255k)

- The increase in the station rehabilitation program was due to a reclosure replacement project at Sandy Cove.

General Plant

2018 vs. 2017 (+$784k)

- In 2018, InnPower implemented an Outage Management System (OMS) and a new Radio System.
- In 2018, InnPower also purchased a double bucket truck.
- In 2018, there were approximately $25k in architectural fees for LEEDs certification and final site inspection of the building.
- In 2017, approximately $55k was spent on fire separations between InnPower facilities and adjoining daycare plus $124k to reimburse the daycare for leaseholds, as part of their lease agreement. Approximately $8k was spent on InnPower's building signage.

2019 Actual to 2018 Actual Variance

Table 2-33: Capital Expenditure Variances 2019 to 2018 Actuals ($'000s)

Investment Category	Historical Period / Actual			
	2019 vs 2018			
	Actual 2018	Actual 2019	Var $	Var %
System Access	2,293	5,349	3,056	133%
System Renewal	1,908	1,526	(381)	(20%)
System Service	276	2,273	1,997	724%
General Plant	1,147	273	(874)	(76%)
Gross Capital Expenditures	5,624	9,421	3,797	68%
Capital Contributions	(2,522)	(6,752)	(4,231)	168%
Net Capital Expenditures	3,102	2,669	(434)	(14%)

<u>System Access</u>

2019 vs. 2018 (+$3.1m)

- Increase in road authority work. This work is non-discretionary driven by MTO, City of Barrie, County of Simcoe and the Town of Innisfil.
- In 2019, work was performed on the highway 89/400 bridge replacement project.

System Renewal

2019 vs. 2018 (-$381k)

- In 2018, the InnPower service territory was subject to a tornado event (higher costs in 2018).
- In 2019, the number of capital trouble calls was lower than in 2018.
- The sub-standard transformer replacement work decreased in 2019 versus 2018 as a result of inspections.
- The switch replacement work decreased in 2019 versus 2018.
- These decreases were partly offset by an increase in the transformer replacement program and reclosure replacement program.

System Service

2019 vs. 2018 (+$2.0m)

- In 2019, there was a major station rehabilitation project associated with Friday Harbour.

General Plant

2019 vs. 2018 (-$874k)

- In 2019, there were no major vehicle purchases.
- In 2019, the OMS Radio System was commissioned.
- In 2019, InnPower purchased miscellaneous software.
- In 2019, InnPower also installed shelving and wire racks in the Stores department.

2020 Actual to 2019 Actual Variance

Table 2-34: Capital Expenditure Variances 2020 to 2019 Actuals ($'000s)

Investment Category	Historical Period / Actual			
	2020 vs 2019			
	Actual 2019	Actual 2020	Var $	Var %
System Access	5,349	7,911	2,562	48%
System Renewal	1,526	2,069	543	36%
System Service	2,273	2,758	485	21%
General Plant	273	649	376	138%
Gross Capital Expenditures	9,421	13,387	3,966	42%
Capital Contributions	(6,752)	(9,028)	(2,275)	34%
Net Capital Expenditures	2,669	4,359	1,691	63%

System Access

2020 vs. 2019 (+$2.6m)

- An increased volume of work associated with new developments led to an increase in from 2019 to 2020.
- In 2020, there was an increase in suite metering projects including the Bistro condos and Friday Harbour projects.

System Renewal

2020 vs. 2019 (+$543k)

- There were more capital trouble calls in 2020 versus 2019, resulting in larger expenditures.
- In 2020, there was a larger pole replacement program versus 2019, as a result of inspections that found a large number of poles deemed to be at or near end of life.
- The increase was partly offset by a decrease in the transformer replacement program.

System Service

2020 vs. 2019 (+$485k)

- The increase in 2020 versus 2019 is primarily due to the continuation of the station rehabilitation project associated with Friday Harbour.

General Plant

2020 vs. 2019 (+$376)

- In 2020, InnPower implemented a radio system upgrade.
- In 2020, InnPower purchased Prophix (financial analytical tool) and Utilismart Retail Settlement Variance Analysis (RSVA) tool.
- In 2020, InnPower also purchased an engineering estimating tool (Quadra).
- In 2020, there were approximately $55k in electrical fees for yard lighting.
- The remaining increase is due to miscellaneous items, such as glass partition for customer service, replacement of compressor and electrical components for air conditioner and miscellaneous electrical work.

2021 Actual to 2020 Actual Variance

Table 2-35: Capital Expenditure Variances 2021 to 2020 Actuals ($'000s)

Investment Category	Historical Period / Actual			
	2021 vs 2020			
	Actual 2020	Actual 2021	Var $	Var %
System Access	7,911	9,560	1,649	21%
System Renewal	2,069	1,812	(257)	(12%)
System Service	2,758	2,535	(222)	(8%)
General Plant	649	1,227	578	89%
Gross Capital Expenditures	13,387	15,134	1,748	13%
Capital Contributions	(9,028)	(10,259)	(1,231)	14%
Net Capital Expenditures	4,359	4,875	516	12%

System Access

2021 vs. 2020 (+$1.7m)

- In 2021, there was an increase in road authority work. In particular, InnPower performed work on the Innisfil Beach Road (IBR) & HWY 400 bridge reconstruction project. This project was driven by the MTO.
- The increase was partially offset by supply chain issues.

System Renewal

2021 vs. 2020 (-$257k)

- There was a decrease in the sub-standard transformer replacement program in 2021 versus 2020.
- There was a decrease in the pole replacement program in 2021 versus 2020, as a result of inspections.
- These decreases were partly offset by increases in the switch and switchgear replacement programs.

System Service

2021 vs. 2020 (-$222k)

- The decrease in 2021 versus 2020 is due to the completion of the station rehabilitation project associated with Friday Harbour.
- The decrease is partially offset by the increase from the station rehabilitation at the Innisfil station.
- The decrease was also partially offset by an increase from a communication improvement project (Radio Repeater added due to poor SCADA communication).

General Plant

2021 vs. 2020 (+$578k)

- In 2021, InnPower purchased a Wajax Radial Boom Derrick (RBD) truck, which accounts for the majority of the increase.
- In 2021, there were approximately $17k in excavations, $11k in concrete sidewalk removal and replacement and $10k in emergency lights.

2022 Actual to 2021 Actual Variance

Table 2-36: Capital Expenditure Variances 2022 to 2021 Actuals ($'000s)

Investment Category	Historical Period / Actual			
	2022 vs 2021			
	Actual 2021	Actual 2022	Var $	Var %
System Access	9,560	7,172	(2,387)	(25%)
System Renewal	1,812	8,460	6,648	367%
System Service	2,535	1,182	(1,354)	(53%)
General Plant	1,227	1,056	(171)	(14%)
Gross Capital Expenditures	15,134	17,870	2,736	18%
Capital Contributions	(10,259)	(14,787)	(4,528)	44%
Net Capital Expenditures	4,875	3,083	(1,792)	(37%)

System Access

2022 vs. 2021 (-$2.4m)

- In 2021, there were several new subdivisions completed versus a small number in 2022.
- In 2022, there was a decrease in non-discretionary road authority work.
- In 2022, InnPower experienced supply chain issues, which caused a decrease in meter related projects.

System Renewal

2022 vs. 2021 (+$6.6m)

- The primary cause of the increase year over year is due to the Metrolinx Electrification Project, which included the reallocation of assets overground to underground at eleven railway crossings.
- There was a year over year increase in the pole replacement program as a result of work that was deferred from 2021.

System Service

2022 vs. 2021 (-$1.4m)

- The decrease is primarily due to the completion of the Innisfil station rehabilitation project that was started in 2021.

General Plant

2022 vs. 2021 (-$171k)

- There were no major vehicle purchases in 2022 compared to 2021.
- There were lower costs in 2022 due to the completion of the GIS and the connectivity between SCADA and GIS projects in 2021.
- In 2022, there were approximately $54k in electrical fees to get power to the yard, $27k in safety rail installation near HVAC equipment and miscellaneous expenses for HVAC system including new motor and new humidifier.

2023 Bridge to 2022 Actual Variance

Table 2-37: Capital Expenditure Variances 2023 Bridge to 2022 Actuals ($'000s)

Investment Category	Forecast Period / Planned			
	2023 vs 2022			
	Actual 2022	Bridge 2023	Var $	Var %
System Access	7,172	25,415	18,242	254%
System Renewal	8,460	9,994	1,534	18%
System Service	1,182	11,967	10,785	913%
General Plant	1,056	1,155	99	9%
Gross Capital Expenditures	17,870	48,530	30,660	172%
Capital Contributions	(14,787)	(37,046)	(22,259)	151%
Net Capital Expenditures	3,083	11,485	8,401	272%

System Access

2023 vs. 2022 (+$18.2m)

- This increase is due to several factors, primarily a large increase in several large developments in Innisfil and new subdivision work.
- The work on the new developments and subdivisions is primarily due to main system feeder expansion required to supply Hewitt and Salem developments in South Barrie
- There are also several expansions in Innisfil.

System Renewal

2023 vs. 2022 (+$1.5m)

- The primary cause of the increase is due to the continuation of the Metrolinx Electrification Project.
- In 2023, there is a planned increase in the voltage regulator and animal mitigation programs.
- The increase is partially offset by a decrease in the pole replacement program and capital trouble call program.
- In 2023, a historical average was used to develop the forecast for many categories.

System Service

2023 vs. 2022 (+$10.8m)

- The increase is primarily associated with station rehabilitation projects and the Barrie Area Transformer Upgrade (BATU) projects.
- In 2023, there is a planned 44kV line extension from Barrie planned.
- In 2023, a historical average was used to develop the forecast for many categories.

General Plant

2023 vs. 2022 (+$99k)

- In 2023, InnPower is planning on implementing an Enterprise Resource Planning (ERP) system.
- In 2023, InnPower is planning on purchasing a small service truck with a bucket.
- In 2023, a historical average was used to develop the forecast for many categories.

2024 Test to 2023 Bridge Variance

Table 2-38: Capital Expenditure Variances 2024 Test to 2023 Bridge ($'000s)

Investment Category	Forecast Period / Planned			
	2024 vs 2023			
	Bridge 2023	Test 2024	Var $	Var %
System Access	25,415	23,410	(2,004)	(8%)
System Renewal	9,994	1,429	(8,565)	(86%)
System Service	11,967	7,519	(4,448)	(37%)
General Plant	1,155	1,022	(133)	(12%)
Gross Capital Expenditures	48,530	33,380	(15,150)	(31%)
Capital Contributions	(37,046)	(24,260)	12,785	(35%)
Net Capital Expenditures	11,485	9,120	(2,365)	(21%)

System Access

2024 vs 2023 (-$2.0m)

- There is a decrease in planned spending on large developments in Innisfil.
- There is a decrease in planned new subdivision work in 2024 versus 2023.
- In 2024, a historical average was used to develop the forecast for many categories.

System Renewal

2024 vs 2023 (-$8.6m)

- The primary cause of the decrease is due to the planned completion of the Metrolinx Electrification Project in 2023.
- The decrease was partly offset by increases in the switchgear replacement program.
- In 2024, a historical average was used to develop the forecast for many categories.

System Service

2024 vs 2023 (-$4.4m)

- The decrease in 2024 versus 2023 is the planned completion of work on the Innisfil TS project, a reduction in station rehabilitation work (due to the completion of a project at Big Bay Point) and the completion of the planned 44kV line extension from Barrie.
- In 2024, a historical average was used to develop the forecast for many categories.

General Plant

2024 vs 2023 (-$133k)

- In 2024, it is assumed that the ERP implementation project is completed.
- There is a decrease in miscellaneous software expenditures from 2023 to 2024.
- In 2024, a historical average was used to develop the forecast for many categories.

2024 Test to 2017 Actual Variance

Table 2-39: Capital Expenditure Variances 2024 Test to 2017 Actual ($'000s)

Investment Category	Forecast Period / Planned			
	2024 vs 2017			
	Actual 2017	Test 2024	Var $	Var %
System Access	1,523	23,410	21,888	1437%
System Renewal	2,553	1,429	(1,124)	(44%)
System Service	21	7,519	7,498	35579%
General Plant	363	1,022	659	181%
Gross Capital Expenditures	4,460	33,380	28,920	648%
Capital Contributions	(1,134)	(24,260)	(23,127)	2040%
Net Capital Expenditures	3,327	9,120	5,793	174%

From 2017 to 2024, InnPower's overall gross capital expenditures increased by $28.9M or 648%. These expenditures were required to deal with customer and system growth, replacing aging infrastructure and to ensure the safe and reliable operation of the system.

3. CAPITAL CONTRIBUTIONS

Capital Contributions represent payments made by customers and developers towards the purchase of distribution equipment on customer-driven jobs.

Tables 2-40 and 2-41 below show InnPower's capital contributions over the 2017 to 2024 period. The pattern of capital contributions is directly related to the type and volume of the projects undertaken.

Capital contributions are primarily associated with the System Access category of capital expenditures.

Table 2-40: Capital Contributions for the Historical Period 2017 to 2022 ($'000s)

Investment Category	Historical Period / Actual															
	2017	2018 vs 2017			2019 vs 2018			2020 vs 2019			2021 vs 2020			2022 vs 2021		
	Actual 2017	Actual 2018	Var $	Var %	Actual 2019	Var $	Var %	Actual 2020	Var $	Var %	Actual 2021	Var $	Var %	Actual 2022	Var $	Var %
Capital Contributions	(1,134)	(2,522)	(1,388)	122%	(6,752)	(4,231)	168%	(9,028)	(2,275)	34%	(10,259)	(1,231)	14%	(14,787)	(4,528)	44%

Table 2-41: Capital Contributions for the Forecasted Period 2023 to 2024 ($'000s)

Investment Category	Forecast Period / Planned					
	Bridge 2023	Var from 2022 $	Test 2024	Var from 2023 $	Var $ 2024 vs 2017	Var % 2024 vs 2017
Capital Contributions	(37,046)	(22,259)	(24,260)	12,785	(23,127)	2040%

2-5-3 DISTRIBUTION SYSTEM PLAN

The Distribution System Plan and the corresponding appendices is attached as Appendix 2-5-3.

2-5-4 CAPITALIZATION POLICY

1. INTRODUCTION

Effective January 1, 2015, InnPower adopted accounting policies that are compliant with Modified International Financial Reporting Standards (MIFRS). These changes to depreciation and capitalization policies were filed and approved by the OEB in InnPower's 2017 Cost of Service application (EB-2016-0085). InnPower confirms that its capitalization policy is consistent with the OEB's regulatory accounting policies, as set out for MIFRS contained in the Report of the Board on Transition to International Financial Reporting Standards (EB-2008-0408) and the OEB's Accounting Procedures Handbook.

1.1 Recognition

An item of Property, Plant and Equipment should be recognized as a capital asset, if and only if, it is probable that future economic benefits associated with the asset will flow to the Company, and the cost of the item can be measured reliably. (IAS 1 67.74 a and b)

Intangible assets are also considered capital assets under this criterion and are recognized as identifiable non-monetary assets that lack physical substance. (IAS 38.8)

<u>Other Criteria for recognition as a capital asset include:</u>

Expenditures incurred to purchase or to build tangible or intangible assets that will provide benefits lasting beyond one year to the Company will be capitalized.

Expenditures incurred to improve (betterment) an existing asset will be capitalized if it is probable that future economic benefits will flow to the Company. Future economic benefits are demonstrated by the expenditure extending the asset's useful life/lifespan or increasing the asset's potential productivity/capacity or potentially lowering operating costs.

InnPower's capital assets typically include distribution facilities, meters, vehicles, office furniture, computer hardware and other equipment.

Intangible assets generally represent land rights and computer software.

Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

1.2 Measurement

Whether capital assets are purchased or constructed by the Company, they are stated at cost and include expenditures that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended.

The cost of self-constructed assets includes direct materials, initial delivery and assembly, labour, employee benefits, professional fees, and any other costs directly attributable to bringing the asset to a working condition for its intended use. Other costs could include expenditures directly attributable to the assets from engineering, overheads, contracted services, and interest or borrowing costs.

Overheads are identified as being costs that support capital and operating activities, specifically within Supply Chain Management, Fleet Operations and Labour costing. Similarly, expenditures included in Overheads must be reviewed to determine whether they are “directly attributable” to bringing the asset to the location and working condition for its intended use (IAS 16.16 b). Interest or borrowing costs should be capitalized on qualifying projects where construction activity extends over one year.

Costs that are not included in the cost of an item of PP&E include training costs, administration, and other general overhead costs.

1.3 Amortization / Depreciation

Depreciation is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of PP&E that is significant in relation to the total cost of the item. PP&E are considered tangible assets. Land and perpetual land rights are not depreciated.

Finite lived intangible assets are amortized over their estimated useful life (IAS 38).

Construction-in-progress assets are not amortized until the item of PP&E is "available for use" (in its location and condition necessary for it to be capable of operating in the manner intended by management) (IAS 16.55).

Depreciation methods, useful lives and residual values are reviewed annually. Changes in useful life and residual values resulting from this review will be accounted for on a prospective basis as a change in accounting estimate in accordance with IAS 8.

Depreciation of an asset ceases when the asset is derecognized. (IAS 16.55). Depreciation does not cease when the asset is idle or retired from active use except when the asset is classified as held for sale.

The depreciation policy or service lives have not changed since the last rebasing.

1.4 Derecognition (Retirements and Disposals)

An item of PP&E or Intangibles will be removed from the capital assets on the balance sheet when it is taken out of service, or abandoned where no future benefits are expected or when sold. The resulting loss equal to its net book value less disposal costs will be recognized in profit and loss. In the case of a sale of an item of PP&E or Intangibles, gains and losses are determined by comparing the proceeds from the disposal with the net book value of the item disposed with the gain or loss recognized in profit or loss. (IAS 16.68)

1.5 Impairments

At the end of each annual reporting period, the Company must assess whether there is any indication that an asset may be impaired, and if so, determine and measure the impairment loss (IAS 36.9).

An item of PP&E or intangible asset is considered impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of the item. IAS 36.12(f) states that a plan to dispose of an asset before the previously expected date is an indicator of impairment that triggers the calculation of the asset's recoverable amount for the

purpose of determining whether the asset is impaired. Further indications of possible impairment are reflected below.

Indications of Impairment [IAS 36.12]

External sources:

- market value declines
- negative changes in technology, markets, economy, or laws
- increases in market interest rates

Internal sources:

- obsolescence or physical damage
- asset is part of a restructuring or held for disposal
- worse economic performance than expected

The above list is not intended to be exhaustive. [IAS 36.13]

If there is an indication that an impairment loss on assets exists, the recoverable amount is estimated. The impairment loss is the amount by which the asset's carrying amount or net book value exceeds its recoverable amount. The impairment loss is recognized in profit or loss.

1.6 Definitions

Tangible Assets

Property, Plant and Equipment as set out in IAS 16.6, indicates that they are a tangible item that:

- are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and
- are expected to be used for more than one period.

Intangible Assets

An intangible asset is an identifiable non-monetary asset without physical substance. An asset is a resource that is controlled by the entity as a result of past events (for example, purchased or self-constructed) and from which future economic benefits (inflows of cash or other assets) are expected. [IAS 38.8] Thus, the three critical attributes of an intangible asset are:

- Identifiable
- Control (power to obtain benefits from the asset) resulting from a past event
- Future economic benefits (such as revenues or reduced future costs)

Identifiable: an intangible asset is identifiable when it: (IAS 38.12) is separable (capable of being separated and sold, transferred, licensed, rented, or exchanged, either individually or together with a related contract) or arises from contractual or other legal rights, regardless of whether those rights are transferable or separable from the entity or from other rights and obligations.

Betterment

A betterment is defined as the cost incurred to enhance the service potential of a capital asset. It can include the increasing of the capacity of the asset, lowering associated operating costs, improving the quality of output, or extending the asset's useful life. Expenditures for betterments are capitalized if the capital asset will provide future economic benefit to the Company.

Repair

A repair is a cost which is incurred in the maintenance of the existing service potential of a capital asset. These costs are normally wear and tear in the normal use of the capital asset and do not enhance the service life of the asset. Repair costs are expensed in the period in which they occur.

Materiality Limits

All expenditures for capital assets, including betterments, are subject to materiality limits.
While an expenditure might meet the definition to qualify as a capital asset, a materiality limit has been established to minimize the cost disadvantages where administration costs of capitalizing an asset may outweigh the intended benefits.

In view of the foregoing, expenditures that are less than $1,000 should be charged to an operating account (expensed). This limit applies to an individual asset, the total costs of a constructed asset, as well as betterments.

Componentization of Assets

For each part of an item of PP&E with a cost that is significant in relation to the total cost of the item, the item shall be depreciated separately (IAS 16.43).

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another part of the same item. Such parts may be grouped in determining the depreciation charge (IAS 16.45).

1.7 Changes to Capitalization Policy

InnPower has not changed its capitalization policy since the last rebasing.

2-5-5 CAPITALIZATION OF OVERHEADS

1. INTRODUCTION

InnPower capitalizes three types of overhead expenses: Labour Burden, Fleet/Truck Costs, and Materials Overhead. These overhead expenses are shown in Table 2-42: Overhead Expenses below. InnPower does not capitalize general administrative costs related to Administration, Human Resources, Regulatory Affairs, Information System Technology, Billing and Collections and Finance.

1.1 Labour Burden

Labour burden include costs that are statutory (CPP, EI, EHT, WSIB) and non-statutory (vacation and other paid days off, sick time and group benefits). Through the time sheet process, staff track their hours by work order, which designates whether the work completed is expensed or capitalized. The labour burden is calculated and allocated to the capital or expense, based on the number of direct labour hours worked.

1.2 Truck/Fleet Costs

Truck/Fleet costs include fuel, repairs, materials, insurance, vehicle depreciation and other costs associated with maintaining InnPower's fleet of vehicles and equipment. Hourly fleet burden rates are reviewed annually. These costs are expensed or capitalized directly to the specific project through the timesheet process by work order.

1.3 Material Overhead

Material overhead costs to be allocated include labour and benefits and any directly attributable costs to monitor inventory and issue materials and supplies.

Material overhead costs are allocated at the rate shown in the table below, with the excess costs allocated on a pro-rated basis. A reconciliation of the material overhead costs is performed at year-end to ensure that all costs are allocated. Material overhead rates are reviewed on a regular basis and revised as required, since these rates can change depending on the value and types of products being handled. Based on the analysis performed in 2021, it was determined that

material costs had increased enough that it was necessary to increase the material overhead rate.

Table 2-42: Overhead Expenses

Overhead	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Test
Labour Burden	53%	52%	53%	55%	56%	54%	55%	55%
Small Truck Rate	19.50/hr	19.50/hr	19.50/hr	19.50/hr	19.50/hr	19.50/hr	19.50/hr	19.50/hr
Large Truck Rate	42.00/hr	42.00/hr	42.00/hr	42.00/hr	42.00/hr	42.00/hr	42.00/hr	42.00/hr
Material Overhead	20%	20%	20%	20%	35%	35%	35%	35%

InnPower has completed Appendix 2-D Overhead Expense of the Chapter 3 appendices showing a breakdown of OM&A before capitalization and capitalized OM&A. This has also been filed as Appendix 2-5-5. Please see Appendix 2-D below in Tables 2-43 and 2-44.

Table 2-43: Appendix 2-D Summary of OM&A Before Capitalization

OM&A Before Capitalization	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Bridge Year	2024 Test Year
Distribution Operations	$1,600,622	$1,396,958	$1,313,975	$1,104,679	$1,548,761	$1,370,149	$1,741,822	$1,974,901
Distribution Maintenance	$616,264	$631,893	$652,489	$762,332	$1,049,233	$948,218	$880,390	$1,115,647
Billing and Collecting	$1,016,438	$1,085,093	$1,132,149	$1,251,092	$1,067,987	$1,475,945	$1,156,048	$1,194,581
Community Relations	$6,406	$72,722	$48,694	$76,635	$104,431	$98,992	$109,700	$113,874
Administrative and General	$2,761,323	$2,584,086	$2,480,413	$3,056,246	$2,675,570	$3,119,310	$3,622,841	$3,916,465
Total OM&A Before Capitalization (B)	**$6,001,053**	**$5,770,751**	**$5,627,720**	**$6,250,983**	**$6,445,982**	**$7,012,614**	**$7,510,801**	**$8,315,469**

Table 2-44: Appendix 2-D Summary of Capitalized OM&A

Capitalized OM&A	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Bridge Year	2024 Test Year
Employee benefits	$227,366	$445,012	$655,964	$859,327	$1,117,063	$1,222,077	$1,399,347	$1,488,388
Costs of site preparation	$264,058	$238,369	$268,096	$344,237	$403,335	$484,512	$496,625	$509,041
Initial delivery and handling costs	$91,346	$175,448	$315,527	$278,907	$229,332	$228,407	$234,117	$239,970
Total Capitalized OM&A (A)	**$582,771**	**$858,830**	**$1,239,587**	**$1,482,471**	**$1,749,730**	**$1,934,996**	**$2,130,089**	**$2,237,399**

2-5-6 SERVICE QUALITY AND RELIABILITY PERFORMANCE SUMMARY

1. INTRODUCTION

InnPower delivers electric power in a form which meets customers' needs by providing reliable service (without power quality issues) and exceptional customer service. When gaps in service quality are identified, InnPower takes appropriate actions by developing solutions that balance performance, risk and cost. Below are highlighted initiatives that InnPower undertakes to deliver reliable and quality electric services to customers.

InnPower reports service quality indicators, which consist of Service Quality Requirements ("SQRs") and service reliability metrics, to the OEB on an annual basis. As per section 2.2.2.8 of the Chapter 2 Filing Requirements for Electricity Distribution Rate applications, this Exhibit provides a summary of the reported SQR, and service reliability metrics reported to the OEB for the last five Historical Years.

In addition, Chapter 7 of the OEB's Distribution System Code outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. A distributor is required to provide the reported SQRs for the last five historical years. A distributor should also provide explanations for material changes in service quality and reliability, and whether and how the DSP addresses these issues. The OEB expects any five-year declining trends in reliability for SAIDI and SAIFI to be explained. If a distributor has reliability targets established in a previously filed DSP, as described below, any underperformance should also be explained.

A completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, must be filed. A distributor must confirm that data is consistent with the scorecard or must explain any inconsistencies. InnPower has filed the OEB's Appendix 2 -G as Attachment 2-5-6. InnPower confirms that the information presented in this Schedule and in Appendix 2 -G is consistent with the Electricity Utility Scorecard.

InnPower plans to maintain SQRs above the OEB's minimum standard. For detailed discussion on InnPower's performance with respect to key SQRs that appear on the Electricity Utility Scorecard, please see Attachment 1-1-10 (G)

Consistent with OEB requirements and best industry practices, InnPower employs two principal metrics to measure the utility's reliability performance. These include System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

2. RELIABILITY METRICS

The historical metrics for InnPower's SAIDI and SAIFI are shown in Tables 2-44 and 2-45 below.

Table 2-45: Historical Reliability Performance Metrics - All Cause Codes

Metric	2017	2018	2019	2020	2021	2022	Average
SAIDI	1.54	5.16	1.57	5.45	3.73	2.52	3.32
SAIFI	1.05	1.34	0.63	2.23	1.37	1.58	1.37
CAIDI	1.47	3.85	2.49	2.44	2.72	1.59	2.42

Table 2-46: Historical Reliability Performance Metrics - LOS and MED Adjusted

Metric	2017	2018	2019	2020	2021	2022	Average
	Loss of Supply Adjusted						
SAIDI	1.54	4.78	1.52	5.07	3.73	2.52	3.19
SAIFI	1.05	1.26	0.61	2.05	1.37	1.58	1.32
CAIDI	1.47	3.79	2.49	2.47	2.72	1.59	2.42
	Loss of Supply and Major Event Days Adjusted						
SAIDI	1.54	2.66	1.52	1.81	1.78	1.04	1.73
SAIFI	1.05	0.88	0.61	1.10	0.70	0.87	0.87
CAIDI	1.47	3.02	2.49	1.65	2.54	1.20	2.06

InnPower's historical SAIDI and SAIFI performance has been consistent, excluding the recorded SAIDI in 2018. InnPower exceeded its SAIDI target in 2018 primarily as a result of faulty equipment and tree encroachments into overhead distribution lines. Since then, InnPower has taken steps to readily identify, troubleshoot and sectionalize problem areas in order to minimize outages going forward. InnPower also experienced a slight increase in SAIDI and SAIFI in 2020 as a result of defective equipment, tree encroachments and adverse weather.

3. SERVICE QUALITY METRICS

InnPower sets a high standard for performance when it comes to customer care. InnPower strives to deliver customer excellence and value through the execution of its investments and operations. InnPower tracks and reports the Service Quality Requirements (SQR) outlined in Chapter 7 of the OEB's Distribution System Code (DSC).

The historical Service Quality Metrics are shown in Table 2-46 below. InnPower has met or exceeded the OEB minimum standards in all years.

Table 2-47: Historical Service Quality Metrics

Service Quality Metric	2017	2018	2019	2020	2021	2022	Minimum Standards
Low Voltage Connections	93.28%	91.84%	99.56%	100.00%	99.50%	95.83%	> 90%
High Voltage Connections	-	-	-	-	-	-	> 90%
Telephone accessibility	80.26%	83.85%	90.40%	92.53%	90.18%	82.96%	> 65%
Appointments met	93.50%	87.21%	98.40%	99.51%	100.00%	100.00%	> 90%
Written response to enquiries	99.46%	99.69%	99.90%	99.46%	99.86%	99.56%	> 80%
Emergency Urban Response	-	-	-	-	-	-	> 80%

Service Quality Metric	2017	2018	2019	2020	2021	2022	Minimum Standards
Emergency Rural Response	95.65%	95.74%	97.92%	100.00%	100.00%	98.04%	> 80%
Telephone call abandon rate	5.55%	3.98%	2.21%	2.51%	1.89%	1.55%	< 10%
Appointment scheduling	97.83%	95.25%	95.88%	99.96%	99.91%	100.00%	> 90%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	> 100%
Reconnection Performance Standard	98.47%	98.90%	100.00%	100.00%	100.00%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	100.00%	100.00%	-	-	-	-	> 90%
Billing Accuracy	99.79%	99.73%	99.88%	99.90%	99.83%	99.87%	> 98%

A full discussion of the Reliability Performance Metrics and Service Quality Metrics can be found in InnPower's Distribution System Plan (Exhibit 2-5-3) - Section 5.2.3 on Performance Measurement for Continuous Improvement.

2-5-7 ADVANCED CAPITAL MODULE

1. INTRODUCTION

As further address in section 5.2.2.4 of InnPower's DSP and its sub-sections, Hydro One Networks Inc.'s (Hydro One) Barrie Area Transmission Upgrade (BATU) project consists of upgrading two existing 115 kV circuits to 230 kV between Essa TS and Barrie TS, constructing new 230 kV connection points at the Essa TS, and upgrading and expanding the existing Barrie TS with new 230–44 kV facilities. The transmission line and station work are required to increase supply capacity to accommodate customer load growth in South Barrie and Innisfil areas and to address immediate end-of-life issues with the current facilities. The BATU Project was the subject of the OEB's Decision and Order in EB-2018-0117 on April 23, 2020, which granted Hydro One leave to construct the project, and approved InnPower's payment of its capital contribution to Hydro One in 5 installments from 2023 through 2027. As noted in the OEB's Decision and Order, "The OEB finds that it is appropriate that InnPower only records in its rate base the amounts that it has paid"[1], which will allow for "the distributor customer earning a return on rate base for any installment payments made on its capital contribution owing."[2]

In the EB-2018-0117 Decision and Order, the OEB accepted a five-year term for capital contribution from InnPower in respect of the BATU project.

In EB-2018-0117, Hydro One proposed a unique loan methodology (the "Loan Methodology") to record the net capital costs associated the BATU project (excluding 100% of the capital contribution) in Hydro One's rate base once in-service, while InnPower would record its capital contribution payments in its rate base as it is paid. In this way, Hydro One treated the five-year term of the capital contribution as loan to InnPower through two DVAs (the Distributor Contribution Sub-account and the Capital Contribution Recovery Differential Sub-account) which the OEB approved.

[1] EB-2018-0117 Decision and Order, page 17
[2] Ibid., pages 16 to 17

During the proceeding, OEB staff argued that InnPower should be able to include the full capital contribution for the BATU in its rate base as an intangible asset when the BATU project goes into service since those assets would be considered used and useful to InnPower. This is forecasted to occur in 2023.

The OEB disagreed, noting that under OEB staff's proposal, InnPower would earn a full return on rate base on as-of-yet unpaid capital contributions. The OEB noted that this could encourage other distributors to defer their capital contribution payments.

1.1 Deferral Accounts

InnPower is requesting approval of a new deferral account; 1508, Other Regulatory Assets, Sub-Account BATU Installment Account. The deferral account is proposed to have four sub-accounts as follows:

- **Sub-Account BATU Installments Paid:** Will record the actual capital contributions paid to Hydro One beyond those that are already included in base rates.
- **Sub-Account BATU Installment, Carrying Charges:** Will record the revenue requirement associated with the capital contributions recorded in the BATU Installments Paid Sub-account, excluding depreciation expense (i.e., return on rate base using InnPower's approved WACC, and PILs).
- **Sub-Account BATU Installment Depreciation Expense:** Will record the depreciation expense associated with the capital contributions recorded in the BATU Installments Paid Sub-Account.
- **Sub-Account BATU Installment Accumulated Depreciation:** Will be credited with the amounts charged to the BATU Installment Depreciation Expense Sub-Account.

1.2 OEB Eligibility Criteria

The proposed account meets the OEB's eligibility criteria for establishing new DVAs as follows:

- **Causation:** The account will only record installment payments that are not already included in base rates. For clarity, that would have the effect of excluding from these accounts the BATU installment paid in 2023 as well as the BATU installment forecasted to be paid in 2024.
- **Materiality:** InnPower's OEB defined materiality threshold is $72,000. Clearly the capital installment payments of $4.12M per year exceed this materiality threshold. In addition, InnPower estimates an annual revenue requirement of $293,828 for each installment ($881,484 cumulatively), which itself well exceeds InnPower's materiality threshold.
- **Prudence:** The BATU project itself was adjudicated to be needed and prudent by the OEB in EB-2018-0117. The new deferral account is required as a direct consequence of the unique Loan Methodology approved by the OEB in EB-2018-0117. The account will ensure that InnPower is able to recover the revenue requirement of the full capital contribution for the BATU, but only starting the date that installments are actually paid to Hydro One. The new deferral account will ensure that InnPower does not suffer a loss on approximately 78% of the installments made to Hydro One, which would be the consequence of using the OEB's ACM model.

1.3 Alternative Options to Deferral Account

InnPower also considered an alternative possibility of utilizing the OEB's Advanced Capital Module (ACM) mechanism to attempt to recover the revenue requirement associated with the installment payments to Hydro One in each of 2025, 2026 and 2027.

As more fully detailed in Table 2-47 below, the result of the OEB's ACM mechanism results in a material deficiency in revenue requirement due to the application of the maximum eligible incremental capital, driven in part due to the impact of high inflation and high growth rates on the arithmetic in the ACM model. With the ACM mechanism, InnPower would not recover 78% of the incremental capital associated with the BATU installments – a result that is neither just nor reasonable.

Table 2-48: ACM Funding Shortfall Analysis

($ millions)	2025	2026	2027	Total
BATU Installment Payment	$4.12	$4.12	$4.12	$12.36
Maximum Eligible Incremental Capital	$1.15	$0.92	$0.67	$2.74 (22%)
ACM Shortfall	**$2.97**	**$3.2**	**$3.45**	**$9.62 (78%)**

In the alternative, and only if the request for approval of the BATU Installment Account is denied, InnPower requests approval of three ACM requests relating to capital contributions paid to Hydro One for InnPower's calculated portions of the Barrie Area Transmission Upgrade (BATU) Project. Specifically, InnPower requests approval of ACM treatment of payments 3, 4, and 5 to Hydro One, which will be made in 2025, 2026, and 2027; each in the amount of $4.12M. The payments in 2023 and 2024 are included in InnPower's 2024 Cost of Service Rates Application. The OEB's ACM is the appropriate mechanism for InnPower to utilize in implementing the OEB's Decision and Order in EB-2018-0117. The following sections address how InnPower's capital contributions toward the BATU Project meet the ACM tests of materiality, need, and prudence. Attached as Appendix 2-5-7 to this evidence is a completed version of the OEB's ICM/ACM Model as it relates to the BATU Project.

2. ACM POLICY

On September 18, 2014, the OEB issued the Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (the ACM Report). The ACM Report evolved the Incremental Capital Module (ICM) initially adopted by the OEB in 2008 to allow distributors to incorporate incremental capital plans into advanced system planning. The ACM allows distributors the opportunity to submit discrete capital projects documented in their Distribution System Plans (DSP) as part of their cost of service applications.

Like the ICM, distributors must demonstrate ACM projects meet the tests of need, materiality, and prudence.[3] Unlike the ICM, the tests of need and prudence are assessed during review of the

[3] ACM Report, page 17

distributor's cost of service application, while materiality is assessed only on a preliminary basis. Materiality is ultimately determined in the distributor's IRM application for the in-service year of the ACM project, at which time the final details of the materiality threshold and maximum eligible incremental capital will be decided. The same application would also identify significant changes from original forecast capital costs.[4]

On January 22, 2016, the OEB issued the Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report (Supplemental Report). The Supplemental Report revised the calculation of the materiality threshold to accommodate a multi-year formula, allow for an annualized growth factor, reduce the deadband from 20% to 10%, and assign a stretch factor of 0.3% for all distributors.

2.1 Materiality

As noted, the materiality test for an ACM project reviewed in a cost of service proceeding is completed on a preliminary basis, with final materiality assessed in the IRM application relating to the in-service year of the ACM project. The ACM Report sets out two materiality tests:

Materiality Threshold

> A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise, they should be dealt with at rebasing.[5]

The materiality threshold applicable to ACM projects is defined in the OEB's Supplemental Report[6], and is embedded within the OEB's ICM/ACM Model. InnPower's net capital expenditures after capital contributions are provided in table 5.2-1 on page 6 of its DSP, provided at Exhibit 2, Tab 5, Schedule 3. Taken together, InnPower's annual net capital expenditures, less the

[4] Ibid, pages 11, 20
[5] ACM Report, page 17
[6] Supplemental Report, page 19

materiality threshold for 2025, 2026 and 2027, yield the maximum eligible incremental capital for each year on a preliminary basis, as shown in Table 2-48 below.

Table 2-49: Incremental Capital

	2025	2026	2027
Net Capital Expenditures	$9,180,000	$9,253,000	$9,328,000
Materiality Threshold	$8,025,497	$8,332,140	$8,658,161
Maximum Eligible Incremental Capital	**$1,154,503**	**$920,860**	**$669,839**

The annual capital contributions required by Hydro One of InnPower for 2025, 2026, and 2027 are $4.12M. InnPower is requesting approval of the maximum eligible incremental capital amount for each of 2025, 2026, and 2027.

Project-Specific Materiality Test

> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.[7]

As noted, InnPower's annual capital contributions for each of 2025, 2026, and 2027 are $4.12M. As shown above, the total net capital expenditures of InnPower over these same years are $9.18M, $9.25M, and $9.32M, respectively. These net capital expenditures are inclusive of the BATU contributions. As such, these capital contributions represent 44.9%, 44.5%, and 44.2% of InnPower's net capital expenditures over 2025, 2026, and 2027, respectively. Clearly, the capital contributions paid for the BATU Project are material in comparison to InnPower's overall capital budget. The BATU Project meets the OEB's project-specific materiality test for ACM treatment.

2.2 Need

With respect to need, the ACM report requires that:

[7] Ibid.

> Amounts must be based on discrete projects and should be directly related to the claimed driver.[8]

As outlined in the OEB's Decision and Order in EB-2018-0117, as well as section 5.2.2.4 of InnPower's DSP, the BATU Project is clearly a discrete project, and InnPower's capital contributions are directly related to the drivers noted.

The ACM Report also requires that "The amounts must clearly be outside of the base upon which the rates were derived."[9] As noted above, InnPower's contributions towards the BATU Project represent nearly half of its net capital expenditures in the years 2025, 2026 and 2027. Given that the maximum eligible incremental capital for the years noted represent only a fraction of the total capital contributions paid toward the BATU Project, and in light of the $4.12M capital contribution paid in 2024 being impacted by the half year rule, the amounts requested for ACM treatment are clearly outside of the basis on which rates will be set beginning in 2024 on completion of this proceeding.

Finally, The ACM Report requires that a distributor pass the Means Test, as defined in the ACM Report; specifically, that a distributor must demonstrate that its most recent actual Regulated ROE did not exceed 300 basis points above Board-approved ROE.[10] As required in the ACM Report, InnPower will demonstrate in each of the IRM proceedings for 2025, 2026, and 2027 that its most recent Regulated ROE did not exceed 300 basis points above OEB-approved ROE.

Subject to elements of the need test which can only be finalized in the IRM proceedings for 2025, 2026, and 2027, InnPower's ACM requests meet the OEB's need test.

[8] ACM Report, page 17
[9] Ibid.
[10] ACM Report, page 15

2.3 Prudence

The OEB reviewed and approved the BATU Project, including InnPower's capital contributions, in EB-2018-0117. The OEB found that on assessing available alternatives, the BATU Project was needed.[11] In addition, on June 30, 2022, Hydro One submitted an update to the OEB, informing it of an 18-month delay relative to expectations outlined in EB-2018-0117, and increased costs to $125M. The impact to InnPower of such changes, as outlined on page 8 of InnPower's DSP, was an increase to InnPower's total contribution to $20.6M. InnPower is ultimately a price-taker of Hydro One with respect to the provision of necessary transmission capacity to support the needs of its customers. InnPower's payment of the required capital contributions is prudent based on the costs determined by Hydro One to meet InnPower customers' growing needs, and the OEB's approval of the BATU Project.

3. SUMMARY

InnPower is requesting approval a new deferral account; 1508, Other Regulatory Assets, Sub-Account BATU Installment Account. The deferral account is proposed to have four sub-accounts as follows:

- **BATU Installments Paid Sub-Account:** Will record the actual capital contributions paid to Hydro One beyond those that are already included in base rates.
- **BATU Installment Return and PILs Recovery Sub-Account:** Will record the revenue requirement associated with the capital contributions recorded in the BATU Installments Paid Sub-account, excluding depreciation expense (i.e., return on rate base using InnPower's approved WACC, and PILs).
- **BATU Installment Depreciation Expense Sub-Account:** Will record the depreciation expense associated with the capital contributions recorded in the BATU Installments Paid Sub-Account.
- **BATU Installment Accumulated Depreciation Sub-Account:** Will be credited with the amounts charged to the BATU Installment Depreciation Expense Sub-Account.
- **BATU Installments, Carrying Charges Sub-Account**: Will record carrying charges based on the amounts recorded in the BATU Installment Return and PILs Recovery and

[11] EB-2018-0117, Decision and Order, page 8

BATU Installment Depreciation Expense Sub-Accounts. Will be calculated as simple interest on the actual amounts recorded in these Sub-Accounts based on the interest rate prescribed by the OEB.

In the alternative, and only if the OEB does not approve this new deferral account, InnPower is requesting approval of three ACM requests relating to capital contributions paid to Hydro One for InnPower's calculated portions of the BATU Project. This request is based on the evidence provided above (including the results of the OEB's ACM model), and the OEB's Decision and Order in EB-2023-0033.

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Appendix 2-2-1 (A)	OEB Appendix 2-BA Fixed Asset Continuity Schedules
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Appendix 2-2-1 (A) OEB Appendix 2-BA Fixed Asset Continuity Schedules

Accounting Standard: MIFRS
Year: 2017

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [8]	Closing Balance	Opening Balance [8]	Additions	Disposals [8]	Closing Balance	
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 688,701	$ 94,703	$ -	$ 783,404	-$ 465,359	-$ 149,759	$ -	-$ 615,118	$ 168,286
CEC	1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ -	$ -	$ 394,446	-$ 40,542	-$ 12,699	$ -	-$ 53,241	$ 341,205
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 7,282,718	$ 76,348	-$ 191,446	$ 7,167,620	-$ 552,117	-$ 253,905	$ 191,446	-$ 614,576	$ 6,553,044
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,727,364	$ 1,321,686	-$ 11,372	$ 11,037,678	-$ 704,935	-$ 269,157	$ 2,829	-$ 971,263	$ 10,066,415
47	1835	Overhead Conductors & Devices	$ 10,914,694	$ 1,224,256	-$ 24,634	$ 12,114,316	-$ 662,189	-$ 232,973	$ 2,388	-$ 892,774	$ 11,221,542
47	1840	Underground Conduit	$ 2,978,799	$ 62,588	$ -	$ 3,041,387	-$ 243,679	-$ 96,053	$ -	-$ 339,732	$ 2,701,656
47	1845	Underground Conductors & Devices	$ 8,006,048	$ 61,020	-$ 609	$ 8,066,459	-$ 753,833	-$ 248,429	$ 609	-$ 1,001,652	$ 7,064,807
47	1850	Line Transformers	$ 5,650,378	$ 641,354	-$ 54,028	$ 6,237,704	-$ 475,913	-$ 175,459	$ 9,653	-$ 641,720	$ 5,595,984
47	1855	Services (Overhead & Underground)	$ 3,878,392	$ 363,406	$ -	$ 4,241,798	-$ 275,508	-$ 110,574	$ -	-$ 386,082	$ 3,855,716
47	1860	Meters	$ 2,295,455	$ 346,375	-$ 5,635	$ 2,636,194	-$ 542,523	-$ 212,231	$ 1,445	-$ 753,309	$ 1,882,885
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,438,239	$ 71,055	$ -	$ 12,509,294	-$ 416,907	-$ 271,409	$ -	-$ 688,316	$ 11,820,978
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 230,265	$ 6,246	$ -	$ 236,511	-$ 58,001	-$ 25,416	$ -	-$ 83,417	$ 153,093
10	1920	Computer Equipment - Hardware	$ 498,996	$ 134,688	-$ 15,927	$ 617,757	-$ 235,520	-$ 99,128	$ 15,030	-$ 319,618	$ 298,140
10	1930	Transportation Equipment	$ 524,916	$ -	$ -	$ 524,916	-$ 349,371	-$ 100,468	$ -	-$ 449,839	$ 75,077
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 25,481	-$ 14,248	$ -	-$ 39,729	$ 95,605
8	1940	Tools, Shop & Garage Equipment	$ 331,421	$ 19,789	$ -	$ 351,210	-$ 123,972	-$ 45,737	$ -	-$ 169,709	$ 181,501
8	1945	Measurement & Testing Equipment	$ 29,667	$ 33,848	$ -	$ 63,515	-$ 12,291	-$ 5,529	$ -	-$ 17,820	$ 45,695
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,558,336	$ 2,963	$ -	$ 2,561,299	-$ 420,336	-$ 189,489	$ -	-$ 609,826	$ 1,951,473
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 13,622,319	-$ 979,572	$ 13,154	-$ 14,588,738	$ 953,970	$ 419,035	-$ 201	$ 1,372,804	-$ 13,215,934
	2005	Property Under Finance Lease[7]	0	0	0	$ -	0	0	0	$ -	$ -
		Sub-Total	**$ 57,006,940**	**$ 3,480,751**	**-$ 290,497**	**$ 60,197,195**	**-$ 5,404,508**	**-$ 2,093,630**	**$ 223,200**	**-$ 7,274,937**	**$ 52,922,258**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,350,000	-$ 56,055	$ -	-$ 2,406,055	$ 70,499	$ 48,822	$ -	$ 119,321	-$ 2,286,734
		Total PP&E for Rate Base Purposes	**$ 54,656,940**	**$ 3,424,696**	**-$ 290,497**	**$ 57,791,140**	**-$ 5,334,009**	**-$ 2,044,808**	**$ 223,200**	**-$ 7,155,616**	**$ 50,635,524**
		Construction Work In Progress	$ 724,781	$ 430,110	$ -	$ 1,154,890				$ -	$ 1,154,890
		Total PP&E	**$ 55,381,721**	**$ 3,854,806**	**-$ 290,497**	**$ 58,946,031**	**-$ 5,334,009**	**-$ 2,044,808**	**$ 223,200**	**-$ 7,155,616**	**$ 51,790,414**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,044,808**			

			Less: *Fully Allocated Depreciation*		
10		Transportation	Transportation	-$	100,468
8		Stores Equipment	Stores Equipment		
47		Deferred Revenue	Deferred Revenue	$	419,035
			Net Depreciation	**-$**	**2,363,374**

Year 2018

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [8]	Closing Balance	Opening Balance [8]	Additions	Disposals [8]	Closing Balance	
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 783,404	$ 168,705	$ -	$ 952,109	-$ 615,118	-$ 129,811	$ -	-$ 744,929	$ 207,180
CEC	1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ -	$ -	$ 394,446	-$ 53,241	-$ 12,699	$ -	-$ 65,940	$ 328,506
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 7,167,620	$ 358,566	-$ 310	$ 7,525,876	-$ 614,576	-$ 256,768	$ -	-$ 871,344	$ 6,654,532
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 11,037,678	$ 717,821	-$ 3,964	$ 11,751,535	-$ 971,263	-$ 291,440	$ 922	-$ 1,261,782	$ 10,489,754
47	1835	Overhead Conductors & Devices	$ 12,114,316	$ 1,420,095	-$ 4,345	$ 13,530,066	-$ 892,774	-$ 256,448	$ 832	-$ 1,148,390	$ 12,381,676
47	1840	Underground Conduit	$ 3,041,387	$ 120,702	$ -	$ 3,162,089	-$ 339,732	-$ 98,348	$ -	-$ 438,080	$ 2,724,009
47	1845	Underground Conductors & Devices	$ 8,066,459	$ 213,614	-$ 123	$ 8,279,950	-$ 1,001,652	-$ 251,863	$ 66	-$ 1,253,450	$ 7,026,500
47	1850	Line Transformers	$ 6,237,704	$ 570,444	$ -	$ 6,808,148	-$ 641,720	-$ 189,385	$ 4,405	-$ 826,699	$ 5,981,449
47	1855	Services (Overhead & Underground)	$ 4,241,798	$ 581,990	-$ 1,070	$ 4,822,717	-$ 386,082	-$ 121,258	$ 52	-$ 507,288	$ 4,315,429
47	1860	Meters	$ 2,636,194	$ 303,605	-$ 16,919	$ 2,922,880	-$ 753,309	-$ 232,679	$ 4,846	-$ 981,142	$ 1,941,738
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,509,294	$ 196,384	$ -	$ 12,705,678	-$ 688,316	-$ 280,177	$ -	-$ 968,492	$ 11,737,185
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 236,511	$ -	$ -	$ 236,511	-$ 83,417	-$ 24,463	$ -	-$ 107,881	$ 128,630
10	1920	Computer Equipment - Hardware	$ 617,757	$ 45,780	-$ 3,631	$ 659,906	-$ 319,618	-$ 103,173	$ 3,631	-$ 419,160	$ 240,746
10	1930	Transportation Equipment	$ 524,916	$ 556,736	-$ 31,192	$ 1,050,460	-$ 449,839	-$ 89,889	$ 31,192	-$ 508,536	$ 541,925
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 39,729	-$ 14,047	$ -	-$ 53,776	$ 81,558
8	1940	Tools, Shop & Garage Equipment	$ 351,210	$ 38,364	$ -	$ 389,574	-$ 169,709	-$ 47,849	$ -	-$ 217,558	$ 172,016
8	1945	Measurement & Testing Equipment	$ 63,515	$ -	$ -	$ 63,515	-$ 17,820	-$ 6,798	$ -	-$ 24,618	$ 38,897
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,561,299	$ 133,588	$ -	$ 2,694,887	-$ 609,826	-$ 186,247	$ -	-$ 796,073	$ 1,898,814
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 14,588,738	-$ 1,359,844	$ 1,030	-$ 15,947,552	$ 1,372,804	$ 446,327	-$ 52	$ 1,819,079	-$ 14,128,472
	2005	Property Under Finance Lease [7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 60,197,195**	**$ 4,066,548**	**-$ 60,524**	**$ 64,203,219**	**-$ 7,274,937**	**-$ 2,147,014**	**$ 45,894**	**-$ 9,376,058**	**$ 54,827,162**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055			-$ 2,406,055	$ 119,321	$ 48,822		$ 168,143	-$ 2,237,912
		Total PP&E for Rate Base Purposes	**$ 57,791,140**	**$ 4,066,548**	**-$ 60,524**	**$ 61,797,165**	**-$ 7,155,616**	**-$ 2,098,193**	**$ 45,894**	**-$ 9,207,915**	**$ 52,589,250**
		Construction Work In Progress	$ 1,154,890	$ 112,206	$ -	$ 1,267,096				$ -	$ 1,267,096
		Total PP&E	**$ 58,946,030**	**$ 4,178,754**	**-$ 60,524**	**$ 63,064,261**	**-$ 7,155,616**	**-$ 2,098,193**	**$ 45,894**	**-$ 9,207,915**	**$ 53,856,346**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 2,098,193**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 89,889
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 446,327
			Net Depreciation	**-$ 2,454,630**

Accounting Standard: MIFRS
Year: 2019

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 952,109	$ 114,859	$ -	$ 1,066,968	-$ 744,929	-$ 126,538	$ -	-$ 871,467	$ 195,501
CEC	1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ 2,950	$ -	$ 397,396	-$ 65,940	-$ 12,729	$ -	-$ 78,669	$ 318,728
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 7,525,876	$ 1,472,953	$ -	$ 8,998,829	-$ 871,344	-$ 287,724	$ 165	-$ 1,158,902	$ 7,839,927
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 11,751,535	$ 3,289,786	-$ 66,523	$ 14,974,799	-$ 1,261,782	-$ 335,120	$ 9,402	-$ 1,587,499	$ 13,387,300
47	1835	Overhead Conductors & Devices	$ 13,530,066	$ 1,670,013	-$ 6,959	$ 15,193,121	-$ 1,148,390	-$ 284,303	$ 1,009	-$ 1,431,684	$ 13,761,437
47	1840	Underground Conduit	$ 3,162,089	$ 343,532	$ -	$ 3,505,621	-$ 438,080	-$ 104,171	-$ 14	-$ 542,264	$ 2,963,357
47	1845	Underground Conductors & Devices	$ 8,279,950	$ 335,065	-$ 2,598	$ 8,612,418	-$ 1,253,450	-$ 258,658	$ 1,623	-$ 1,510,484	$ 7,101,933
47	1850	Line Transformers	$ 6,808,148	$ 1,038,208	-$ 10,611	$ 7,835,745	-$ 826,699	-$ 209,328	$ 12,925	-$ 1,023,103	$ 6,812,642
47	1855	Services (Overhead & Underground)	$ 4,822,717	$ 598,428	$ -	$ 5,421,145	-$ 507,288	-$ 134,459	$ -	-$ 641,748	$ 4,779,398
47	1860	Meters	$ 2,922,880	$ 186,792	-$ 6,376	$ 3,103,296	-$ 981,142	-$ 243,372	$ 2,248	-$ 1,222,266	$ 1,881,030
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,705,678	$ 38,914	$ -	$ 12,744,591	-$ 968,492	-$ 282,515	$ -	-$ 1,251,008	$ 11,493,583
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 236,511	$ 39,714	$ -	$ 276,224	-$ 107,881	-$ 25,208	$ -	-$ 133,089	$ 143,135
10	1920	Computer Equipment - Hardware	$ 659,906	$ 45,304	-$ 1,889	$ 703,321	-$ 419,160	-$ 98,850	$ 757	-$ 517,253	$ 186,068
10	1930	Transportation Equipment	$ 1,050,460	$ 6,428	-$ 48,051	$ 1,008,837	-$ 508,536	-$ 79,104	$ 40,449	-$ 547,190	$ 461,647
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 53,776	-$ 13,474	$ -	-$ 67,250	$ 68,085
8	1940	Tools, Shop & Garage Equipment	$ 389,574	$ 22,265	-$ 10,719	$ 401,120	-$ 217,558	-$ 49,554	$ 4,291	-$ 262,821	$ 138,299
8	1945	Measurement & Testing Equipment	$ 63,515	$ 5,225	$ -	$ 68,740	-$ 24,618	-$ 6,660	$ -	-$ 31,278	$ 37,462
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,694,887	$ -	$ -	$ 2,694,887	-$ 796,073	-$ 183,583	$ -	-$ 979,656	$ 1,715,231
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 15,947,552	-$ 6,432,656	$ -	-$ 22,380,208	$ 1,819,079	$ 540,241	$ -	$ 2,359,320	-$ 20,020,888
	2005	Property Under Finance Lease [7]	$ -	$ 170,612	$ -	$ 170,612	$ -	-$ 20,931	$ -	-$ 20,931	$ 149,681
		Sub-Total	**$ 64,203,219**	**$ 2,948,391**	**-$ 153,724**	**$ 66,997,886**	**-$ 9,376,058**	**-$ 2,216,040**	**$ 72,856**	**-$ 11,519,242**	**$ 55,478,644**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055			-$ 2,406,055	$ 168,143	$ 48,822		$ 216,965	-$ 2,189,090
		Total PP&E for Rate Base Purposes	**$ 61,797,165**	**$ 2,948,391**	**-$ 153,724**	**$ 64,591,832**	**-$ 9,207,915**	**-$ 2,167,218**	**$ 72,856**	**-$ 11,302,277**	**$ 53,289,554**
		Construction Work In Progress	$ 1,267,096	$ 2,469,820	$ -	$ 3,736,916				$ -	$ 3,736,916
		Total PP&E	**$ 63,064,261**	**$ 5,418,211**	**-$ 153,724**	**$ 68,328,748**	**-$ 9,207,915**	**-$ 2,167,218**	**$ 72,856**	**-$ 11,302,277**	**$ 57,026,470**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [8]									
		Total						**-$ 2,167,218**			

			Less: *Fully Allocated Depreciation*		
10		Transportation	Transportation	-$	100,035
8		Stores Equipment	Stores Equipment		
47		Deferred Revenue	Deferred Revenue	$	540,241
			Net Depreciation	**-$**	**2,607,425**

Accounting Standard: MIFRS

Year: 2020

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 1,066,968	$ 240,107	$ -	$ 1,307,075	-$ 871,467	-$ 150,767	$ -	-$ 1,022,234	$ 284,841
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 78,669	-$ 12,793	$ -	-$ 91,462	$ 305,935
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,998,829	$ 3,617,853	-$ 1,201	$ 12,615,481	-$ 1,158,902	-$ 400,048	$ 28,602	-$ 1,530,348	$ 11,085,132
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 14,974,799	$ 3,208,762	-$ 17,486	$ 18,166,075	-$ 1,587,499	-$ 389,142	$ 1,546	-$ 1,975,095	$ 16,190,980
47	1835	Overhead Conductors & Devices	$ 15,193,121	$ 2,310,861	-$ 31,208	$ 17,472,773	-$ 1,431,684	-$ 321,241	$ 18,441	-$ 1,734,484	$ 15,738,290
47	1840	Underground Conduit	$ 3,505,621	$ 494,242	$ -	$ 3,999,862	-$ 542,264	-$ 114,945	$ -	-$ 657,209	$ 3,342,653
47	1845	Underground Conductors & Devices	$ 8,612,418	$ 429,863	-$ 7,370	$ 9,034,911	-$ 1,510,484	-$ 268,767	$ 1,909	-$ 1,777,342	$ 7,257,568
47	1850	Line Transformers	$ 7,835,745	$ 1,409,176	$ 18,691	$ 9,263,612	-$ 1,023,103	-$ 240,391	$ 9,289	-$ 1,254,205	$ 8,009,406
47	1855	Services (Overhead & Underground)	$ 5,421,145	$ 580,972	-$ 515	$ 6,001,602	-$ 641,748	-$ 148,578	$ -	-$ 790,325	$ 5,211,277
47	1860	Meters	$ 3,103,296	$ 299,278	-$ 11,305	$ 3,391,269	-$ 1,222,266	-$ 253,186	$ 106,660	-$ 1,368,792	$ 2,022,477
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,744,591	$ 69,709	$ -	$ 12,814,300	-$ 1,251,008	-$ 284,378	$ -	-$ 1,535,386	$ 11,278,914
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 276,224	$ 5,438	$ -	$ 281,663	-$ 133,089	-$ 25,789	$ -	-$ 158,878	$ 122,785
10	1920	Computer Equipment - Hardware	$ 703,321	$ 90,162	-$ 7,899	$ 785,584	-$ 517,253	-$ 88,702	$ 6,321	-$ 599,635	$ 185,949
10	1930	Transportation Equipment	$ 1,008,837	$ 18,630	$ -	$ 1,027,467	-$ 547,190	-$ 81,144	$ 0	-$ 628,334	$ 399,133
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 67,250	-$ 12,976	$ -	-$ 80,226	$ 55,108
8	1940	Tools, Shop & Garage Equipment	$ 401,120	$ 17,941	$ -	$ 419,061	-$ 262,821	-$ 37,556	$ -	-$ 300,378	$ 118,683
8	1945	Measurement & Testing Equipment	$ 68,740	$ -	$ -	$ 68,740	-$ 31,278	-$ 6,606	$ -	-$ 37,885	$ 30,856
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,694,887	$ 238,750	$ -	$ 2,933,637	-$ 979,656	-$ 186,508	$ -	-$ 1,166,164	$ 1,767,473
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 22,380,208	-$ 8,545,158	$ 45,102	-$ 30,880,264	$ 2,359,320	$ 742,274	-$ 28,754	$ 3,072,840	-$ 27,807,424
	2005	Property Under Finance Lease [7]	$ 170,612	$ 227,479	$ -	$ 398,091	-$ 20,931	-$ 97,053	$ -	-$ 117,984	$ 280,107
		Sub-Total	**$ 66,997,886**	**$ 4,714,066**	**-$ 13,192**	**$ 71,698,760**	**-$ 11,519,242**	**-$ 2,378,298**	**$ 144,013**	**-$ 13,753,526**	**$ 57,945,234**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 216,965	$ 48,822	$ -	$ 265,786	-$ 2,140,268
		Total PP&E for Rate Base Purposes	**$ 64,591,832**	**$ 4,714,066**	**-$ 13,192**	**$ 69,292,705**	**-$ 11,302,277**	**-$ 2,329,476**	**$ 144,013**	**-$ 13,487,740**	**$ 55,804,965**
		Construction Work In Progress	$ 3,736,916	$ 1,383,609	$ -	$ 5,120,525				$ -	$ 5,120,525
		Total PP&E	**$ 68,328,748**	**$ 6,097,675**	**-$ 13,192**	**$ 74,413,230**	**-$ 11,302,277**	**-$ 2,329,476**	**$ 144,013**	**-$ 13,487,740**	**$ 60,925,490**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [8]									
		Total						**-$ 2,329,476**			

			Less: *Fully Allocated Depreciation*		
10		Transportation	Transportation	-$	178,197
8		Stores Equipment	Stores Equipment		
47		Deferred Revenue	Deferred Revenue	$	742,274
			Net Depreciation	**-$**	**2,893,552**

Accounting Standard: MIFRS

Year: 2021

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 1,307,075	$ 152,645	$ -	$ 1,459,720	-$ 1,022,234	-$ 171,775	$ -	-$ 1,194,009	$ 265,711
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 91,462	-$ 12,758	$ -	-$ 104,219	$ 293,177
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 12,615,481	$ 2,419,931	$ -	$ 15,035,412	-$ 1,530,348	-$ 470,450	$ -	-$ 2,000,799	$ 13,034,613
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 18,166,075	$ 4,034,416	-$ 7,542	$ 22,192,949	-$ 1,975,095	-$ 480,144	$ 1,831	-$ 2,453,408	$ 19,739,541
47	1835	Overhead Conductors & Devices	$ 17,472,773	$ 3,114,575	-$ 306,019	$ 20,281,330	-$ 1,734,484	-$ 369,357	$ 41,000	-$ 2,062,841	$ 18,218,490
47	1840	Underground Conduit	$ 3,999,862	$ 577,679	$ -	$ 4,577,541	-$ 657,209	-$ 128,046	$ -	-$ 785,255	$ 3,792,286
47	1845	Underground Conductors & Devices	$ 9,034,911	$ 724,359	-$ 3,821	$ 9,755,448	-$ 1,777,342	-$ 282,177	$ 1,166	-$ 2,058,354	$ 7,697,094
47	1850	Line Transformers	$ 9,263,612	$ 1,293,633	-$ 46,280	$ 10,510,964	-$ 1,254,205	-$ 272,574	$ 23,085	-$ 1,503,694	$ 9,007,270
47	1855	Services (Overhead & Underground)	$ 6,001,602	$ 743,587	-$ 44,932	$ 6,700,257	-$ 790,325	-$ 163,074	$ 8,793	-$ 944,607	$ 5,755,650
47	1860	Meters	$ 3,391,269	$ 231,866	-$ 22,879	$ 3,600,256	-$ 1,368,792	-$ 267,711	$ 10,794	-$ 1,625,710	$ 1,974,547
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,814,300	$ 43,734	$ -	$ 12,858,034	-$ 1,535,386	-$ 284,735	$ -	-$ 1,820,120	$ 11,037,914
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 281,663	$ 23,353	$ -	$ 305,015	-$ 158,878	-$ 25,317	$ -	-$ 184,195	$ 120,820
10	1920	Computer Equipment - Hardware	$ 785,584	$ 24,956	$ -	$ 810,540	-$ 599,635	-$ 74,712	$ -	-$ 674,347	$ 136,193
10	1930	Transportation Equipment	$ 1,027,467	$ 668,543	$ -	$ 1,696,010	-$ 628,334	-$ 146,011	$ -	-$ 774,345	$ 921,665
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 80,226	-$ 12,720	$ -	-$ 92,946	$ 42,389
8	1940	Tools, Shop & Garage Equipment	$ 419,061	$ 74,701	$ -	$ 493,762	-$ 300,378	-$ 26,045	$ -	-$ 326,423	$ 167,339
8	1945	Measurement & Testing Equipment	$ 68,740	$ 2,290	$ -	$ 71,030	-$ 37,885	-$ 6,205	$ -	-$ 44,090	$ 26,940
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 2,933,637	$ 251,848	$ -	$ 3,185,485	-$ 1,166,164	-$ 201,020	$ -	-$ 1,367,185	$ 1,818,300
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 30,880,264	-$ 7,381,961	$ 14,421	-$ 38,247,803	$ 3,072,840	$ 926,727	-$ 715	$ 3,998,853	-$ 34,248,951
	2005	Property Under Finance Lease [7]	$ 398,091	$ 135,521	-$ 297,549	$ 236,063	-$ 117,984	-$ 107,346	$ 125,851	-$ 99,479	$ 136,584
		Sub-Total	**$ 71,698,760**	**$ 7,135,674**	**-$ 714,601**	**$ 78,119,834**	**-$ 13,753,526**	**-$ 2,575,450**	**$ 211,805**	**-$ 16,117,171**	**$ 62,002,663**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 265,786	$ 48,822	$ -	$ 314,608	-$ 2,091,447
		Total PP&E for Rate Base Purposes	**$ 69,292,705**	**$ 7,135,674**	**-$ 714,601**	**$ 75,713,779**	**-$ 13,487,740**	**-$ 2,526,628**	**$ 211,805**	**-$ 15,802,563**	**$ 59,911,216**
		Construction Work In Progress	$ 5,120,525	$ -	-$ 1,313,631	$ 3,806,894				$ -	$ 3,806,894
		Total PP&E	**$ 74,413,230**	**$ 7,135,674**	**-$ 2,028,232**	**$ 79,520,673**	**-$ 13,487,740**	**-$ 2,526,628**	**$ 211,805**	**-$ 15,802,563**	**$ 63,718,110**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [8]									
		Total						**-$ 2,526,628**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 253,356
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 926,727
			Net Depreciation	**-$ 3,199,999**

Accounting Standard: MIFRS
Year: 2022

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [8]	Closing Balance	Opening Balance [8]	Additions	Disposals [8]	Closing Balance	
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 1,459,720	$ 321,121	$ -	$ 1,780,841	-$ 1,194,009	-$ 203,750	$ -	-$ 1,397,759	$ 383,082
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 104,219	-$ 12,758	$ -	-$ 116,977	$ 280,419
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 15,035,412	$ 467,974	$ -	$ 15,503,386	-$ 2,000,799	-$ 516,471	$ -	-$ 2,517,269	$ 12,986,117
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,192,949	$ 3,566,867	-$ 12,897	$ 25,746,919	-$ 2,453,408	-$ 558,303	$ 4,845	-$ 3,006,867	$ 22,740,053
47	1835	Overhead Conductors & Devices	$ 20,281,330	$ 1,181,705	-$ 24,496	$ 21,438,539	-$ 2,062,841	-$ 406,986	$ 7,973	-$ 2,461,853	$ 18,976,685
47	1840	Underground Conduit	$ 4,577,541	$ 4,028,775	$ -	$ 8,606,316	-$ 785,255	-$ 185,942	$ -	-$ 971,197	$ 7,635,119
47	1845	Underground Conductors & Devices	$ 9,755,448	$ 1,394,496	-$ 7,161	$ 11,142,784	-$ 2,058,354	-$ 308,457	$ 2,843	-$ 2,363,968	$ 8,778,815
47	1850	Line Transformers	$ 10,510,964	$ 1,001,922	-$ 165,527	$ 11,347,359	-$ 1,503,694	-$ 297,882	$ 20,963	-$ 1,780,613	$ 9,566,745
47	1855	Services (Overhead & Underground)	$ 6,700,257	$ 552,537	$ -	$ 7,252,794	-$ 944,607	-$ 177,470	$ -	-$ 1,122,077	$ 6,130,717
47	1860	Meters	$ 3,600,256	$ 228,496	-$ 40,901	$ 3,787,852	-$ 1,625,710	-$ 276,481	$ 19,422	-$ 1,882,769	$ 1,905,083
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,858,034	$ 143,855	$ -	$ 13,001,890	-$ 1,820,120	-$ 286,618	$ -	-$ 2,106,738	$ 10,895,152
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 305,015	$ 2,165	$ -	$ 307,180	-$ 184,195	-$ 25,668	$ -	-$ 209,863	$ 97,317
10	1920	Computer Equipment - Hardware	$ 810,540	$ 84,647	$ -	$ 895,187	-$ 674,347	-$ 62,906	$ -	-$ 737,253	$ 157,934
10	1930	Transportation Equipment	$ 1,696,010	$ 48,945	$ -	$ 1,744,955	-$ 774,345	-$ 221,390	$ 8,242	-$ 987,494	$ 757,462
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 92,946	-$ 12,410	$ -	-$ 105,356	$ 29,978
8	1940	Tools, Shop & Garage Equipment	$ 493,762	$ 53,427	$ -	$ 547,189	-$ 326,423	-$ 28,879	$ -	-$ 355,302	$ 191,887
8	1945	Measurement & Testing Equipment	$ 71,030	$ 2,425	$ -	$ 73,455	-$ 44,090	-$ 5,608	$ -	-$ 49,698	$ 23,758
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 3,185,485	$ 293,063	$ -	$ 3,478,547	-$ 1,367,185	-$ 217,616	$ -	-$ 1,584,800	$ 1,893,747
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 38,247,803	-$ 8,996,458	$ 3,302	-$ 47,240,959	$ 3,998,853	$ 1,115,463	-$ 404	$ 5,113,912	-$ 42,127,047
	2005	Property Under Finance Lease[7]	$ 236,063	$ 75,328	-$ 170,612	$ 140,779	-$ 99,479	-$ 41,298	$ 110,185	-$ 30,591	$ 110,187
		Sub-Total	**$ 78,119,834**	**$ 4,451,290**	**-$ 418,291**	**$ 82,152,832**	**-$ 16,117,171**	**-$ 2,731,429**	**$ 174,068**	**-$ 18,674,532**	**$ 63,478,300**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 314,608	$ 48,822	$ -	$ 363,430	-$ 2,042,625
		Total PP&E for Rate Base Purposes	**$ 75,713,779**	**$ 4,451,290**	**-$ 418,291**	**$ 79,746,778**	**-$ 15,802,563**	**-$ 2,682,607**	**$ 174,068**	**-$ 18,311,102**	**$ 61,435,676**
		Construction Work In Progress	$ 3,806,894	$ 2,201,416	$ -	$ 6,008,309				$ -	$ 6,008,309
		Total PP&E	**$ 79,520,673**	**$ 6,652,705**	**-$ 418,291**	**$ 85,755,087**	**-$ 15,802,563**	**-$ 2,682,607**	**$ 174,068**	**-$ 18,311,102**	**$ 67,443,985**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,682,607**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 262,688
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,115,463
			Net Depreciation	**-$ 3,535,382**

Accounting Standard: MIFRS

Year: 2023

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [5]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [5]	Additions	Disposals [6]	Closing Balance	
	1609	Capital Contributions Paid	$ -	$ 4,099,270	$ -	$ 4,099,270	$ -	-$ 81,985	$ -	-$ 81,985	$ 4,017,285
12	1611	Computer Software (Formally known as Account 1925)	$ 1,780,841	$ 326,300	$ -	$ 2,107,141	-$ 1,397,759	-$ 220,851	$ -	-$ 1,618,610	$ 488,531
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 116,977	-$ 12,758	$ -	-$ 129,735	$ 267,661
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ 1,003,404	$ -	$ 1,003,404	$ -	-$ 12,543	$ -	-$ 12,543	$ 990,861
47	1820	Distribution Station Equipment <50 kV	$ 15,503,386	$ 6,472,154	$ -	$ 21,975,540	-$ 2,517,269	-$ 580,002	$ -	-$ 3,097,271	$ 18,878,269
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 25,746,919	$ 30,063,401	$ -	$ 55,810,320	-$ 3,006,867	-$ 1,111,586	$ -	-$ 4,118,452	$ 51,691,868
47	1835	Overhead Conductors & Devices	$ 21,438,539	$ 1,181,500	$ -	$ 22,620,039	-$ 2,461,853	-$ 408,732	$ -	-$ 2,870,586	$ 19,749,453
47	1840	Underground Conduit	$ 8,606,316	$ 3,460,166	$ -	$ 12,066,482	-$ 971,197	-$ 271,275	$ -	-$ 1,242,472	$ 10,824,010
47	1845	Underground Conductors & Devices	$ 11,142,784	$ 36,515	$ -	$ 11,179,299	-$ 2,363,968	-$ 299,707	$ -	-$ 2,663,676	$ 8,515,623
47	1850	Line Transformers	$ 11,347,359	$ 246,000	$ -	$ 11,593,359	-$ 1,780,613	-$ 296,684	$ -	-$ 2,077,297	$ 9,516,062
47	1855	Services (Overhead & Underground)	$ 7,252,794	$ 279,000	$ -	$ 7,531,794	-$ 1,122,077	-$ 178,764	$ -	-$ 1,300,841	$ 6,230,952
47	1860	Meters	$ 3,787,852	$ 533,782	$ -	$ 4,321,634	-$ 1,882,769	-$ 293,240	$ -	-$ 2,176,009	$ 2,145,625
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 13,001,890	$ 75,000	$ -	$ 13,076,890	-$ 2,106,738	-$ 286,453	$ -	-$ 2,393,191	$ 10,683,699
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 307,180	$ -	$ -	$ 307,180	-$ 209,863	-$ 25,677	$ -	-$ 235,540	$ 71,641
10	1920	Computer Equipment - Hardware	$ 895,187	$ 79,600	$ -	$ 974,787	-$ 737,253	-$ 79,851	$ -	-$ 817,104	$ 157,683
10	1930	Transportation Equipment	$ 1,744,955	$ 475,690	$ -	$ 2,220,646	-$ 987,494	-$ 27,467	$ -	-$ 1,014,960	$ 1,205,685
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 105,356	-$ 12,631	$ -	-$ 117,987	$ 17,347
8	1940	Tools, Shop & Garage Equipment	$ 547,189	$ 78,750	$ -	$ 625,939	-$ 355,302	-$ 32,722	$ -	-$ 388,024	$ 237,915
8	1945	Measurement & Testing Equipment	$ 73,455	$ -	$ -	$ 73,455	-$ 49,698	-$ 5,851	$ -	-$ 55,549	$ 17,906
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 3,478,547	$ 119,640	$ -	$ 3,598,187	-$ 1,584,800	-$ 225,946	$ -	-$ 1,810,746	$ 1,787,441
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 47,240,959	-$ 37,045,575	$ -	-$ 84,286,534	$ 5,113,912	$ 1,823,643	$ -	$ 6,937,555	-$ 77,348,979
	2005	Property Under Finance Lease [7]	$ 140,779	$ 475,689	$ -	$ 616,468	-$ 30,591	-$ 110,901	$ -	-$ 141,493	$ 474,975
		Sub-Total	**$ 82,152,832**	**$ 11,960,286**	**$ -**	**$ 94,113,118**	**-$ 18,674,532**	**-$ 2,751,985**	**$ -**	**-$ 21,426,517**	**$ 72,686,602**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 363,430	$ 48,822	$ -	$ 412,252	-$ 1,993,803
		Total PP&E for Rate Base Purposes	**$ 79,746,778**	**$ 11,960,286**	**$ -**	**$ 91,707,064**	**-$ 18,311,102**	**-$ 2,703,163**	**$ -**	**-$ 21,014,265**	**$ 70,692,799**
		Construction Work In Progress	$ 6,008,309	$ -	-$ 6,008,309	$ -				$ -	$ -
		Total PP&E	**$ 85,755,087**	**$ 11,960,286**	**-$ 6,008,309**	**$ 91,707,064**	**-$ 18,311,102**	**-$ 2,703,163**	**$ -**	**-$ 21,014,265**	**$ 70,692,799**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 2,703,163**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 110,901
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 1,823,643
			Net Depreciation	**-$ 4,415,904**

Accounting Standard: MIFRS
Year: 2024

Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance [8]	Additions [4]	Disposals [8]	Closing Balance	Opening Balance [8]	Additions	Disposals [8]	Closing Balance	
	1609	Capital Contributions Paid	$ 4,099,270	$ 4,120,000	$ -	$ 8,219,270	-$ 81,985	-$ 246,371	$ -	-$ 328,356	$ 7,890,914
12	1611	Computer Software (Formally known as Account 1925)	$ 2,107,141	$ 165,000	$ -	$ 2,272,141	-$ 1,618,610	-$ 260,673	$ -	-$ 1,879,283	$ 392,858
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 129,735	-$ 12,758	$ -	-$ 142,493	$ 254,903
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 1,003,404	$ -	$ -	$ 1,003,404	-$ 12,543	-$ 25,085	$ -	-$ 37,628	$ 965,776
47	1820	Distribution Station Equipment <50 kV	$ 21,975,540	$ 3,158,000	$ -	$ 25,133,540	-$ 3,097,271	-$ 569,488	$ -	-$ 3,666,759	$ 21,466,781
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 55,810,320	$ 20,907,736	$ -	$ 76,718,056	-$ 4,118,452	-$ 1,381,751	$ -	-$ 5,500,204	$ 71,217,853
47	1835	Overhead Conductors & Devices	$ 22,620,039	$ 423,723	$ -	$ 23,043,762	-$ 2,870,586	-$ 417,299	$ -	-$ 3,287,885	$ 19,755,877
47	1840	Underground Conduit	$ 12,066,482	$ 3,500	$ -	$ 12,069,982	-$ 1,242,472	-$ 291,123	$ -	-$ 1,533,595	$ 10,536,387
47	1845	Underground Conductors & Devices	$ 11,179,299	$ 120,525	$ -	$ 11,299,824	-$ 2,663,676	-$ 300,733	$ -	-$ 2,964,408	$ 8,335,415
47	1850	Line Transformers	$ 11,593,359	$ 242,625	$ -	$ 11,835,984	-$ 2,077,297	-$ 299,736	$ -	-$ 2,377,033	$ 9,458,951
47	1855	Services (Overhead & Underground)	$ 7,531,794	$ 2,872,748	$ -	$ 10,404,542	-$ 1,300,841	-$ 199,814	$ -	-$ 1,500,655	$ 8,903,887
47	1860	Meters	$ 4,321,634	$ 509,500	$ -	$ 4,831,134	-$ 2,176,009	-$ 306,256	$ -	-$ 2,482,264	$ 2,348,869
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 13,076,890	$ 75,000	$ -	$ 13,151,890	-$ 2,393,191	-$ 287,286	$ -	-$ 2,680,477	$ 10,471,413
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 307,180	$ -	$ -	$ 307,180	-$ 235,540	-$ 25,677	$ -	-$ 261,216	$ 45,964
10	1920	Computer Equipment - Hardware	$ 974,787	$ 194,303	$ -	$ 1,169,090	-$ 817,104	-$ 94,024	$ -	-$ 911,128	$ 257,962
10	1930	Transportation Equipment	$ 2,220,646	$ 470,000	$ -	$ 2,690,646	-$ 1,014,960	-$ 74,727	$ -	-$ 1,089,688	$ 1,600,958
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 117,987	-$ 12,631	$ -	-$ 130,619	$ 4,716
8	1940	Tools, Shop & Garage Equipment	$ 625,939	$ 82,688	$ -	$ 708,627	-$ 388,024	-$ 36,766	$ -	-$ 424,790	$ 283,836
8	1945	Measurement & Testing Equipment	$ 73,455	$ -	$ -	$ 73,455	-$ 55,549	-$ 5,851	$ -	-$ 61,400	$ 12,055
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 3,598,187	$ 35,000	$ -	$ 3,633,187	-$ 1,810,746	-$ 228,406	$ -	-$ 2,039,153	$ 1,594,035
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 84,286,534	-$ 24,260,348	$ -	-$ 108,546,882	$ 6,937,555	$ 2,253,932	$ -	$ 9,191,487	-$ 99,355,395
	2005	Property Under Finance Lease [7]	$ 616,468	$ -	-$ 65,451	$ 551,017	-$ 141,493	-$ 110,901	$ -	-$ 252,394	$ 298,623
		Sub-Total	**$ 94,113,118**	**$ 9,120,000**	**-$ 65,451**	**$ 103,167,667**	**-$ 21,426,517**	**-$ 2,933,425**	**$ -**	**-$ 24,359,941**	**$ 78,807,726**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 412,252	$ 48,822	$ -	$ 461,074	-$ 1,944,981
		Total PP&E for Rate Base Purposes	**$ 91,707,064**	**$ 9,120,000**	**-$ 65,451**	**$ 100,761,612**	**-$ 21,014,265**	**-$ 2,884,603**	**$ -**	**-$ 23,898,867**	**$ 76,862,745**
		Construction Work In Progress				$ -				$ -	$ -
		Total PP&E	**$ 91,707,064**	**$ 9,120,000**	**-$ 65,451**	**$ 100,761,612**	**-$ 21,014,265**	**-$ 2,884,603**	**$ -**	**-$ 23,898,867**	**$ 76,862,745**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [8]									
		Total						**-$ 2,884,603**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 110,901
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 2,253,932
			Net Depreciation	**-$ 5,027,633**

Appendix 2-3-1 (A) OEB Appendix 2-BB Service Life Comparison

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers & Fixtures	45	2%				
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers & Fixtures	60	2%				
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors & Devices	45	2%				
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors & Devices	60	2%				
	9	OH Transformers & Voltage Regulators			30	40	60								
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55	1835	Overhead Conductors & Devices	45	2%				
TS & MS	12	Power Transformers	Overall		30	45	60	1850	Line Transformers	40	3%				
								1815	Transformer Station Equipment	40	3%				
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30	1820	Distribution Station Equipment <50 kV	30	3%				
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60								
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30	1845	Underground Conductors & Devices	40	3%	40	3%	No	Yes
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Underground Conductors & Devices	40	3%	40	3%	No	Yes
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1855	Services	40	3%				
	32	Secondary Cables in Duct			35	40	60	1855	Services	40	3%				
	33	Network Transformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%				
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1840	Underground Conduit	60	2%				
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors & Devices	40	3%				
	40	Ducts			30	50	85	1840	Underground Conduit	40	3%				
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1980	System Supervisor Equipment	15	7%				

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture & Equipment	10	10%				
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%				
		Trailers	5	20	1930	Transportation Equipment	20	5%				
		Trucks under 3 Tons	5	10	1930	Transportation Equipment	5	20%				
3	Administrative Buildings		50	75	1908	Buildings & Fixtures	50	2%				
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	50	2%				
		Parking	25	30	1908	Buildings and Fixtures	30	3%				
		Fence	25	60	1908	Buildings and Fixtures	25	4%				
		Roof	20	30	1908	Buildings and Fixtures	20	5%				
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	5	20%				
		Software	2	5	1611	Computer Software	3	33%				
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%				
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop & Garage Equipment	10	10%				
		Measurement & Testing Equipment	5	10	1945	Measurement & Testing Equipment	10	10%				
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35	1860	Meters	25	4%				
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%				
11	Wholesale Energy Meters		15	30								
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	15	7%				
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

Appendix 2-3-1 (B) OEB Appendix 2-C Depreciation and Amortization Schedules

Year 2017

Account	Description	Book Values				Service Lives		Depreciation Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1611	Computer Software (Formally known as Account 1925)	$ 688,701	$ 385,483	$ 94,703	$ -	$ 350,570	2.34	42.72%	**149,759**	149,759	**0**
1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ 15,109	$ -	$ -	$ 379,337	29.87	3.35%	**12,699**	12,699	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1820	Distribution Station Equipment <50 kV	$ 7,282,718	$ 145,914	$ 76,348	$ 191,446	$ 6,983,532	27.50	3.64%	**253,905**	253,905	**0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1830	Poles, Towers & Fixtures	$ 9,727,364	$ 244,060	$ 1,321,686	$ 11,372	$ 10,132,775	37.65	2.66%	**269,157**	269,157	**0**
1835	Overhead Conductors & Devices	$ 10,914,694	$ 240,652	$ 1,224,256	$ 24,634	$ 11,261,536	48.34	2.07%	**232,973**	232,973	**0**
1840	Underground Conduit	$ 2,978,799	$ 70,931	$ 62,588	$ -	$ 2,939,162	30.60	3.27%	**96,053**	96,053	**0**
1845	Underground Conductors & Devices	$ 8,006,048	$ 268,452	$ 61,020	$ 609	$ 7,767,497	31.27	3.20%	**248,429**	248,429	**0**
1850	Line Transformers	$ 5,650,378	$ 172,818	$ 641,354	$ 54,028	$ 5,744,209	32.74	3.05%	**175,459**	175,459	**0**
1855	Services (Overhead & Underground)	$ 3,878,392	$ 81,145	$ 363,406	$ -	$ 3,978,949	35.98	2.78%	**110,574**	110,574	**0**
1860	Meters	$ 2,295,455	$ 173,885	$ 346,375	$ 5,635	$ 2,289,121	10.79	9.27%	**212,231**	212,231	**0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -		0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,088,239	$ 118,500	$ 15,000	$ -	$ 9,977,239	44.82	2.23%	**222,587**	222,587	**0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (5 years)	$ 230,265	$ 18,450	$ 6,246	$ -	$ 214,938	8.46	11.82%	**25,416**	25,416	**0**
1920	Computer Equipment - Hardware	$ 498,996	$ 128,235	$ 134,688	$ 15,927	$ 422,178	4.26	23.48%	**99,128**	99,128	**0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1930	Transportation Equipment	$ 524,916	$ 142,462	$ -	$ -	$ 382,454	3.81	26.27%	**100,468**	100,468	**0**
1935	Stores Equipment	$ 135,334	$ 2,837	$ -	$ -	$ 132,497	9.30	10.75%	**14,248**	14,248	**0**
1940	Tools, Shop & Garage Equipment	$ 331,421	$ 41,275	$ 19,789	$ -	$ 300,041	6.56	15.24%	**45,737**	45,737	**0**
1945	Measurement & Testing Equipment	$ 29,667	$ 5,568	$ 33,848	$ -	$ 41,024	7.42	13.48%	**5,529**	5,529	**0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1980	System Supervisor Equipment	$ 2,558,336	$ 173,072	$ 2,963	$ -	$ 2,386,746	12.60	7.94%	**189,489**	189,489	**0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
2440	Deferred Revenue	-$ 13,622,319	-$ 268,925	-$ 979,572	-$ 13,154	-$ 13,830,026	33.00	3.03%	**-419,035**	-419,035	**0**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
	Total	**$ 54,656,940**	**$ 4,225,012**	**$ 3,424,696**	**$ 290,497**	**$ 51,853,780**			**2,044,808**	**2,044,808**	**0**

Year 2018

Account	Description	Book Values				Service Lives		Depreciation Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1611	Computer Software (Formally known as Account 1925)	$ 783,404	$ 570,535	$ 168,705	$ -	$ 297,221	2.29	43.67%	**129,811**	129,811	**0**
1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ 15,109	$ -	$ -	$ 379,337	29.87	3.35%	**12,699**	12,699	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1820	Distribution Station Equipment <50 kV	$ 7,167,620	$ 145,914	$ 358,566	$ 310	$ 7,200,680	28.04	3.57%	**256,768**	256,768	**0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1830	Poles, Towers & Fixtures	$ 11,037,678	$ 243,982	$ 717,821	$ 3,964	$ 11,148,642	38.25	2.61%	**291,440**	291,440	**0**
1835	Overhead Conductors & Devices	$ 12,114,316	$ 240,652	$ 1,420,095	$ 4,345	$ 12,579,366	49.05	2.04%	**256,448**	256,448	**0**
1840	Underground Conduit	$ 3,041,387	$ 70,931	$ 120,702	$ -	$ 3,030,807	30.82	3.24%	**98,348**	98,348	**0**
1845	Underground Conductors & Devices	$ 8,066,459	$ 268,452	$ 213,614	$ 123	$ 7,904,691	31.38	3.19%	**251,863**	251,863	**0**
1850	Line Transformers	$ 6,237,704	$ 172,818	$ 570,444	$ -	$ 6,350,108	33.53	2.98%	**189,385**	189,385	**0**
1855	Services (Overhead & Underground)	$ 4,241,798	$ 81,145	$ 581,990	$ 1,070	$ 4,450,577	36.70	2.72%	**121,258**	121,258	**0**
1860	Meters	$ 2,636,194	$ 174,197	$ 303,605	$ 16,919	$ 2,596,881	11.16	8.96%	**232,679**	232,679	**0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,103,239	$ 118,500	$ 196,384	$ -	$ 10,082,931	43.58	2.29%	**231,355**	231,355	**0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (5 years)	$ 236,511	$ 22,438	$ -	$ -	$ 214,073	8.75	11.43%	**24,463**	24,463	**0**
1920	Computer Equipment - Hardware	$ 617,757	$ 158,494	$ 45,780	$ 3,631	$ 478,522	4.64	21.56%	**103,173**	103,173	**0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1930	Transportation Equipment	$ 524,916	$ 463,011	$ 556,736	$ 31,192	$ 309,082	3.44	29.08%	**89,889**	89,889	**0**
1935	Stores Equipment	$ 135,334	$ 4,037	$ -	$ -	$ 131,297	9.35	10.70%	**14,047**	14,047	**0**
1940	Tools, Shop & Garage Equipment	$ 351,210	$ 44,587	$ 38,364	$ -	$ 325,806	6.81	14.69%	**47,849**	47,849	**0**
1945	Measurement & Testing Equipment	$ 63,515	$ 6,242	$ -	$ -	$ 57,273	8.42	11.87%	**6,798**	6,798	**0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1980	System Supervisor Equipment	$ 2,561,299	$ 191,136	$ 133,588	$ -	$ 2,436,957	13.08	7.64%	**186,247**	186,247	**0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
2440	Deferred Revenue	-$ 14,588,738	-$ 268,925	-$ 1,359,844	-$ 1,030	-$ 14,998,704	33.60	2.98%	**-446,327**	-446,327	**0**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
	Total	**$ 57,791,140**	**$ 4,788,344**	**$ 4,066,548**	**$ 60,524**	**$ 54,975,547**			**2,098,193**	**2,098,193**	**0**

Year 2019

Account	Description	Book Values				Service Lives		Depreciation Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1611	Computer Software (Formally known as Account 1925)	$ 952,109	$ 688,701	$ 114,859	$ -	$ 320,838	2.54	39.44%	**126,538**	126,538	**0**
1612	Land Rights (Formally known as Account 1906)	$ 394,446	$ 15,109	$ 2,950	$ -	$ 380,812	29.92	3.34%	**12,729**	12,729	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1820	Distribution Station Equipment <50 kV	$ 7,525,876	$ 147,467	$ 1,472,953	$ -	$ 8,114,885	28.20	3.55%	**287,724**	287,724	**0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1830	Poles, Towers & Fixtures	$ 11,751,535	$ 243,793	$ 3,289,786	$ 66,523	$ 13,086,113	39.05	2.56%	**335,120**	335,120	**0**
1835	Overhead Conductors & Devices	$ 13,530,066	$ 240,652	$ 1,670,013	$ 6,959	$ 14,117,462	49.66	2.01%	**284,303**	284,303	**0**
1840	Underground Conduit	$ 3,162,089	$ 70,931	$ 343,532	$ -	$ 3,262,924	31.32	3.19%	**104,171**	104,171	**0**
1845	Underground Conductors & Devices	$ 8,279,950	$ 268,452	$ 335,065	$ 2,598	$ 8,176,433	31.61	3.16%	**258,658**	258,658	**0**
1850	Line Transformers	$ 6,808,148	$ 172,818	$ 1,038,208	$ 10,611	$ 7,143,823	34.13	2.93%	**209,328**	209,328	**0**
1855	Services (Overhead & Underground)	$ 4,822,717	$ 81,145	$ 598,428	$ -	$ 5,040,786	37.49	2.67%	**134,459**	134,459	**0**
1860	Meters	$ 2,922,880	$ 214,061	$ 186,792	$ 6,376	$ 2,795,839	11.49	8.70%	**243,372**	243,372	**0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,299,623	$ 118,500	$ 38,914	$ -	$ 10,200,580	43.65	2.29%	**233,693**	233,693	**0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (5 years)	$ 236,511	$ 28,596	$ 39,714	$ -	$ 227,771	9.04	11.07%	**25,208**	25,208	**0**
1920	Computer Equipment - Hardware	$ 659,906	$ 226,920	$ 45,304	$ 1,889	$ 453,749	4.59	21.79%	**98,850**	98,850	**0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1930	Transportation Equipment	$ 1,050,460	$ 413,187	$ 6,428	$ 48,051	$ 592,436	7.49	13.35%	**79,104**	79,104	**0**
1935	Stores Equipment	$ 135,334	$ 7,634	$ -	$ -	$ 127,700	9.48	10.55%	**13,474**	13,474	**0**
1940	Tools, Shop & Garage Equipment	$ 389,574	$ 47,371	$ 22,265	$ 10,719	$ 342,617	6.91	14.46%	**49,554**	49,554	**0**
1945	Measurement & Testing Equipment	$ 63,515	$ 8,970	$ 5,225	$ -	$ 57,158	8.58	11.65%	**6,660**	6,660	**0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1980	System Supervisor Equipment	$ 2,694,887	$ 231,439	$ -	$ -	$ 2,463,448	13.42	7.45%	**183,583**	183,583	**0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
2440	Deferred Revenue	-$ 15,947,552	-$ 268,925	-$ 6,432,656	$ -	-$ 18,894,954	34.98	2.86%	**-540,242**	-540,241	**0**
2005	Property Under Finance Lease	$ -	$ -	$ 170,612	$ -	$ 85,306	4.08	24.54%	**20,931**	20,931	**0**
	Total	**$ 61,797,165**	**$ 5,021,911**	**$ 2,948,391**	**$ 153,724**	**$ 58,095,725**			**2,167,218**	**2,167,218**	**0**

Year 2020

Account	Description	Book Values				Service Lives		Depreciation Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1611	Computer Software (Formally known as Account 1925)	$ 1,066,968	$ 783,404	$ 240,107	$ -	$ 403,617	2.68	37.35%	**150,767**	150,767	**0**
1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ 15,109	$ -	$ -	$ 382,287	29.88	3.35%	**12,793**	12,793	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1820	Distribution Station Equipment <50 kV	$ 8,998,829	$ 150,440	$ 3,617,853	$ 1,201	$ 10,656,115	26.64	3.75%	**400,048**	400,048	**0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1830	Poles, Towers & Fixtures	$ 14,974,799	$ 243,793	$ 3,208,762	$ 17,486	$ 16,317,902	41.93	2.38%	**389,142**	389,142	**0**
1835	Overhead Conductors & Devices	$ 15,193,121	$ 240,652	$ 2,310,860	$ 31,208	$ 16,076,690	50.05	2.00%	**321,241**	321,241	**0**
1840	Underground Conduit	$ 3,505,621	$ 70,931	$ 494,242	$ -	$ 3,681,811	32.03	3.12%	**114,945**	114,945	**0**
1845	Underground Conductors & Devices	$ 8,612,418	$ 268,452	$ 429,863	$ 7,370	$ 8,551,527	31.82	3.14%	**268,767**	268,767	**0**
1850	Line Transformers	$ 7,835,745	$ 172,818	$ 1,409,176	-$ 18,691	$ 8,386,206	34.89	2.87%	**240,391**	240,391	**0**
1855	Services (Overhead & Underground)	$ 5,421,145	$ 81,145	$ 580,972	$ 515	$ 5,629,971	37.89	2.64%	**148,578**	148,578	**0**
1860	Meters	$ 3,103,296	$ 223,273	$ 299,278	$ 11,305	$ 3,018,357	11.92	8.39%	**253,186**	253,186	**0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,338,536	$ 118,500	$ 69,709	$ -	$ 10,254,891	43.53	2.30%	**235,556**	235,556	**0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (5 years)	$ 276,224	$ 40,106	$ 5,438	$ -	$ 238,837	9.26	10.80%	**25,789**	25,789	**0**
1920	Computer Equipment - Hardware	$ 703,321	$ 376,418	$ 90,162	$ 7,899	$ 364,085	4.10	24.36%	**88,702**	88,702	**0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1930	Transportation Equipment	$ 1,008,837	$ 413,187	$ 18,630	$ -	$ 604,965	7.46	13.41%	**81,144**	81,144	**0**
1935	Stores Equipment	$ 135,334	$ 9,128	$ -	$ -	$ 126,206	9.73	10.28%	**12,976**	12,976	**0**
1940	Tools, Shop & Garage Equipment	$ 401,120	$ 192,506	$ 17,941	$ -	$ 217,585	5.79	17.26%	**37,556**	37,556	**0**
1945	Measurement & Testing Equipment	$ 68,740	$ 9,298	$ -	$ -	$ 59,443	9.00	11.11%	**6,606**	6,606	**0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1980	System Supervisor Equipment	$ 2,694,887	$ 243,911	$ 238,750	$ -	$ 2,570,351	13.78	7.26%	**186,508**	186,508	**0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
2440	Deferred Revenue	-$ 22,380,208	-$ 268,925	-$ 8,545,158	-$ 45,102	-$ 26,338,759	35.48	2.82%	**-742,274**	-742,274	**0**
2005	Property Under Finance Lease	$ 170,612	$ -	$ 227,479	$ -	$ 284,352	2.93	34.13%	**97,053**	97,053	**0**
	Total	**$ 64,591,832**	**$ 5,449,235**	**$ 4,714,065**	**$ 13,192**	**$ 61,486,437**			**2,329,476**	**2,329,476**	**0**

Year 2021

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1611	Computer Software (Formally known as Account 1925)	$ 1,307,075	$ 952,109	$ 152,645	$ -	$ 431,288	2.51	39.83%	**171,775**	171,775	**0**
1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ 15,109	$ -	$ -	$ 382,287	29.96	3.34%	**12,758**	12,758	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1820	Distribution Station Equipment <50 kV	$ 12,615,481	$ 174,200	$ 2,419,931	$ -	$ 13,651,246	29.02	3.45%	**470,450**	470,450	**0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1830	Poles, Towers & Fixtures	$ 18,166,075	$ 325,830	$ 4,034,416	$ 7,542	$ 19,849,911	41.34	2.42%	**480,144**	480,144	**0**
1835	Overhead Conductors & Devices	$ 17,472,773	$ 244,624	$ 3,114,575	$ 306,019	$ 18,479,418	50.03	2.00%	**369,357**	369,357	**0**
1840	Underground Conduit	$ 3,999,862	$ 70,931	$ 577,679	$ -	$ 4,217,771	32.94	3.04%	**128,046**	128,046	**0**
1845	Underground Conductors & Devices	$ 9,034,911	$ 268,452	$ 724,359	$ 3,821	$ 9,124,817	32.34	3.09%	**282,177**	282,177	**0**
1850	Line Transformers	$ 9,263,612	$ 172,818	$ 1,293,633	$ 46,280	$ 9,691,330	35.55	2.81%	**272,574**	272,574	**0**
1855	Services (Overhead & Underground)	$ 6,001,602	$ 81,145	$ 743,587	$ 44,932	$ 6,247,318	38.31	2.61%	**163,074**	163,074	**0**
1860	Meters	$ 3,391,269	$ 223,535	$ 231,866	$ 22,879	$ 3,260,788	12.18	8.21%	**267,711**	267,711	**0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,408,245	$ 118,500	$ 43,734	$ -	$ 10,311,613	43.71	2.29%	**235,913**	235,913	**0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (5 years)	$ 281,663	$ 50,531	$ 23,353	$ -	$ 242,808	9.59	10.43%	**25,317**	25,317	**0**
1920	Computer Equipment - Hardware	$ 785,584	$ 471,539	$ 24,956	$ -	$ 326,522	4.37	22.88%	**74,712**	74,712	**0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1930	Transportation Equipment	$ 1,027,467	$ 454,176	$ 668,543	$ -	$ 907,562	6.22	16.09%	**146,011**	146,011	**0**
1935	Stores Equipment	$ 135,334	$ 10,237	$ -	$ -	$ 125,098	9.83	10.17%	**12,720**	12,720	**0**
1940	Tools, Shop & Garage Equipment	$ 419,061	$ 230,489	$ 74,701	$ -	$ 225,923	8.67	11.53%	**26,045**	26,045	**0**
1945	Measurement & Testing Equipment	$ 68,740	$ 15,346	$ 2,290	$ -	$ 54,539	8.79	11.38%	**6,205**	6,205	**0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1980	System Supervisor Equipment	$ 2,933,637	$ 246,737	$ 251,848	$ -	$ 2,812,824	13.99	7.15%	**201,020**	201,020	**0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
2440	Deferred Revenue	-$ 30,880,264	-$ 279,424	-$ 7,381,961	-$ 14,421	-$ 34,277,399	36.99	2.70%	**-926,727**	-926,727	**0**
2005	Property Under Finance Lease	$ 398,091	$ -	$ 135,521	$ 297,549	$ 168,302	1.57	63.78%	**107,346**	107,346	**0**
	Total	**$ 69,292,705**	**$ 5,911,974**	**$ 7,135,674**	**$ 714,601**	**$ 66,233,968**			**2,526,628**	**2,526,628**	**0**

Year 2022

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	0.00	0.00%	**0**	0	0
1611	Computer Software (Formally known as Account 1925)	$ 1,459,720	$ 1,066,968	$ 321,121	$ -	$ 553,312	2.72	36.82%	**203,750**	203,750	0
1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ 15,109	$ -	$ -	$ 382,287	29.96	3.34%	**12,758**	12,758	0
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	0
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1820	Distribution Station Equipment <50 kV	$ 15,035,412	$ 174,200	$ 467,974	$ -	$ 15,095,199	29.23	3.42%	**516,471**	516,471	0
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1830	Poles, Towers & Fixtures	$ 22,192,949	$ 323,377	$ 3,566,867	$ 12,897	$ 23,640,109	42.34	2.36%	**558,303**	558,303	0
1835	Overhead Conductors & Devices	$ 20,281,330	$ 241,761	$ 1,181,705	$ 24,496	$ 20,605,925	50.63	1.98%	**406,986**	406,986	0
1840	Underground Conduit	$ 4,577,541	$ 70,931	$ 4,028,775	$ -	$ 6,520,998	35.07	2.85%	**185,942**	185,942	0
1845	Underground Conductors & Devices	$ 9,755,448	$ 268,144	$ 1,394,496	$ 7,161	$ 10,177,391	32.99	3.03%	**308,457**	308,457	0
1850	Line Transformers	$ 10,510,964	$ 172,256	$ 1,001,922	$ 165,527	$ 10,674,142	35.83	2.79%	**297,882**	297,882	0
1855	Services (Overhead & Underground)	$ 6,700,257	$ 81,145	$ 552,537	$ -	$ 6,895,380	38.85	2.57%	**177,470**	177,470	0
1860	Meters	$ 3,600,256	$ 227,450	$ 228,496	$ 40,901	$ 3,446,154	12.46	8.02%	**276,481**	276,481	0
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	0
1908	Buildings & Fixtures	$ 10,451,980	$ 118,500	$ 143,855	$ -	$ 10,405,407	43.76	2.29%	**237,796**	237,796	0
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1915	Office Furniture & Equipment (5 years)	$ 305,015	$ 52,318	$ 2,165	$ -	$ 253,780	9.89	10.11%	**25,668**	25,668	0
1920	Computer Equipment - Hardware	$ 810,540	$ 604,339	$ 84,647	$ -	$ 248,525	3.95	25.31%	**62,906**	62,906	0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1930	Transportation Equipment	$ 1,696,010	$ 454,176	$ 48,945	$ -	$ 1,266,306	5.72	17.48%	**221,390**	221,390	0
1935	Stores Equipment	$ 135,334	$ 13,582	$ -	$ -	$ 121,752	9.81	10.19%	**12,410**	12,410	0
1940	Tools, Shop & Garage Equipment	$ 493,762	$ 240,352	$ 53,427	$ -	$ 280,124	9.70	10.31%	**28,879**	28,879	0
1945	Measurement & Testing Equipment	$ 71,030	$ 20,879	$ 2,425	$ -	$ 51,364	9.16	10.92%	**5,608**	5,608	0
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1980	System Supervisor Equipment	$ 3,185,485	$ 266,839	$ 293,063	$ -	$ 3,065,177	14.09	7.10%	**217,616**	217,616	0
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	0
2440	Deferred Revenue	-$ 38,247,803	-$ 279,424	-$ 8,996,458	-$ 3,302	-$ 42,463,306	38.07	2.63%	**-1,115,463**	-1,115,463	0
2005	Property Under Finance Lease	$ 236,063	-$ 322,763	$ 75,328	$ 170,612	$ 425,878	10.31	9.70%	**41,298**	41,298	0
	Total	**$ 75,713,779**	**$ 5,875,227**	**$ 4,451,290**	**$ 418,291**	**$ 71,645,905**			**2,682,607**	**2,682,607**	**0**

Year 2023

Account	Description	Book Values				Service Lives		Depreciation Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ 4,099,270	$ -	$ 2,049,635	25.00	4.00%	**81,985**	81,985	**0**
1611	Computer Software (Formally known as Account 1925)	$ 1,780,841	$ 1,307,075	$ 326,300	$ -	$ 636,916	2.88	34.68%	**220,851**	220,851	**0**
1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ 15,109	$ -	$ -	$ 382,287	29.96	3.34%	**12,758**	12,758	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ 1,003,404	$ -	$ 501,702	40.00	2.50%	**12,543**	12,543	**0**
1820	Distribution Station Equipment <50 kV	$ 15,503,386	$ 175,987	$ 6,472,154	$ -	$ 18,563,477	32.01	3.12%	**580,002**	580,002	**0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1830	Poles, Towers & Fixtures	$ 25,746,919	$ 325,141	$ 30,063,401	$ -	$ 40,453,479	36.39	2.75%	**1,111,586**	1,111,586	**0**
1835	Overhead Conductors & Devices	$ 21,438,539	$ 241,761	$ 1,181,500	$ -	$ 21,787,528	53.31	1.88%	**408,732**	408,732	**0**
1840	Underground Conduit	$ 8,606,316	$ 70,931	$ 3,460,166	$ -	$ 10,265,468	37.84	2.64%	**271,275**	271,275	**0**
1845	Underground Conductors & Devices	$ 11,142,784	$ 268,165	$ 36,515	$ -	$ 10,892,876	36.35	2.75%	**299,707**	299,707	**0**
1850	Line Transformers	$ 11,347,359	$ 173,425	$ 246,000	$ -	$ 11,296,933	38.08	2.63%	**296,684**	296,684	**0**
1855	Services (Overhead & Underground)	$ 7,252,794	$ 81,145	$ 279,000	$ -	$ 7,311,148	40.90	2.45%	**178,764**	178,764	**0**
1860	Meters	$ 3,787,852	$ 228,612	$ 533,782	$ -	$ 3,826,131	13.05	7.66%	**293,240**	293,240	**0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,595,835	$ 118,500	$ 75,000	$ -	$ 10,514,835	44.25	2.26%	**237,631**	237,631	**0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (5 years)	$ 307,180	$ 60,444	$ -	$ -	$ 246,737	9.61	10.41%	**25,677**	25,677	**0**
1920	Computer Equipment - Hardware	$ 895,187	$ 664,246	$ 79,600	$ -	$ 270,741	3.39	29.49%	**79,851**	79,851	**0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1930	Transportation Equipment	$ 1,744,955	$ 469,622	$ 475,690	$ -	$ 1,513,178	55.09	1.82%	**27,467**	27,467	**0**
1935	Stores Equipment	$ 135,334	$ 13,582	$ -	$ -	$ 121,752	9.64	10.37%	**12,631**	12,631	**0**
1940	Tools, Shop & Garage Equipment	$ 547,189	$ 247,312	$ 78,750	$ -	$ 339,252	10.37	9.65%	**32,722**	32,722	**0**
1945	Measurement & Testing Equipment	$ 73,455	$ 25,804	$ -	$ -	$ 47,651	8.14	12.28%	**5,851**	5,851	**0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1980	System Supervisor Equipment	$ 3,478,547	$ 316,454	$ 119,640	$ -	$ 3,221,913	14.26	7.01%	**225,946**	225,946	**0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
2440	Deferred Revenue	-$ 47,240,959	-$ 279,424	-$ 37,045,575	$ -	-$ 65,484,322	35.91	2.78%	**-1,823,643**	-1,823,643	**0**
2005	Property Under Finance Lease	$ 140,779	$ -	$ 475,689	$ -	$ 378,623	3.41	29.29%	**110,901**	110,901	**0**
	Total	**$ 79,746,778**	**$ 6,588,980**	**$ 11,960,286**	**$ -**	**$ 77,088,305**			**2,703,163**	**2,703,163**	**0**

Year 2024

Account	Description	Book Values				Service Lives		Depreciation Expense			
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ 4,099,270	$ -	$ 4,120,000	$ -	$ 6,159,270	25.00	4.00%	**246,371**	246,371	**0**
1611	Computer Software (Formally known as Account 1925)	$ 2,107,141	$ 1,459,720	$ 165,000	$ -	$ 729,921	2.80	35.71%	**260,673**	260,673	**0**
1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ 15,109	$ -	$ -	$ 382,287	29.96	3.34%	**12,758**	12,758	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1808	Buildings	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1815	Transformer Station Equipment >50 kV	$ 1,003,404	$ -	$ -	$ -	$ 1,003,404	40.00	2.50%	**25,085**	25,085	**0**
1820	Distribution Station Equipment <50 kV	$ 21,975,540	$ 176,391	$ 3,158,000	$ -	$ 23,378,149	41.05	2.44%	**569,488**	569,488	**0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1830	Poles, Towers & Fixtures	$ 55,810,320	$ 326,485	$ 20,907,736	$ -	$ 65,937,703	47.72	2.10%	**1,381,751**	1,381,751	**0**
1835	Overhead Conductors & Devices	$ 22,620,039	$ 241,763	$ 423,723	$ -	$ 22,590,137	54.13	1.85%	**417,299**	417,299	**0**
1840	Underground Conduit	$ 12,066,482	$ 70,931	$ 3,500	$ -	$ 11,997,301	41.21	2.43%	**291,123**	291,123	**0**
1845	Underground Conductors & Devices	$ 11,179,299	$ 268,165	$ 120,525	$ -	$ 10,971,396	36.48	2.74%	**300,733**	300,733	**0**
1850	Line Transformers	$ 11,593,359	$ 173,469	$ 242,625	$ -	$ 11,541,203	38.50	2.60%	**299,736**	299,736	**0**
1855	Services (Overhead & Underground)	$ 7,531,794	$ 81,145	$ 2,872,748	$ -	$ 8,887,022	44.48	2.25%	**199,814**	199,814	**0**
1860	Meters	$ 4,321,634	$ 1,322,741	$ 509,500	$ -	$ 3,253,642	10.62	9.41%	**306,256**	306,256	**0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,670,835	$ 118,500	$ 75,000	$ -	$ 10,589,835	44.41	2.25%	**238,464**	238,464	**0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1915	Office Furniture & Equipment (5 years)	$ 307,180	$ 69,271	$ -	$ -	$ 237,909	9.27	10.79%	**25,677**	25,677	**0**
1920	Computer Equipment - Hardware	$ 974,787	$ 710,549	$ 194,303	$ -	$ 361,390	3.84	26.02%	**94,024**	94,024	**0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1930	Transportation Equipment	$ 2,220,646	$ 476,050	$ 470,000	$ -	$ 1,979,596	26.49	3.77%	**74,727**	74,727	**0**
1935	Stores Equipment	$ 135,334	$ 18,130	$ -	$ -	$ 117,204	9.28	10.78%	**12,631**	12,631	**0**
1940	Tools, Shop & Garage Equipment	$ 625,939	$ 263,987	$ 82,688	$ -	$ 403,296	10.97	9.12%	**36,766**	36,766	**0**
1945	Measurement & Testing Equipment	$ 73,455	$ 29,667	$ -	$ -	$ 43,788	7.48	13.36%	**5,851**	5,851	**0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1980	System Supervisor Equipment	$ 3,598,187	$ 375,604	$ 35,000	$ -	$ 3,240,083	14.19	7.05%	**228,406**	228,406	**0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**0**	0	**0**
2440	Deferred Revenue	-$ 84,286,534	-$ 279,424	-$ 24,260,348	$ -	-$ 96,137,284	42.65	2.34%	**-2,253,932**	-2,253,932	**0**
2005	Property Under Finance Lease	$ 616,468	$ -	$ -	$ 65,451	$ 551,017	4.97	20.13%	**110,901**	110,901	**0**
	Total	**$ 91,707,064**	**$ 7,983,344**	**$ 9,120,000**	**$ 65,451**	**$ 82,058,999**			**2,884,603**	**2,884,603**	**0**

Appendix 2-4-1 (A) OEB Appendix 2-ZA Commodity Expense Forecast

Step 1: **Commodity Pricing**

Forecasted Commodity Prices	Table 1: Average RPP Supply Cost Summary*		**non-RPP**	**RPP**
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$58.33	$58.33
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$39.04	$39.04
Adjustments ($/MWh)				($3.97)
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$93.40**

Step 2: **Commodity Expense**

(volumes for the test year is loss adjusted)

Commodity

					2024 Test Year					
Customer		**Revenue**	**Expense**							
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705	-		2,355,841	187,855,319	$ 0.05833	$ 0.09340	$17,683,103
GS < 50	kWh	4010	4705	-		5,059,452	40,841,551	$ 0.05833	$ 0.09340	$4,109,719
GS > 50	kWh	4035	4705	9,226,027		44,720,219	2,706,896	$ 0.05833	$ 0.09340	$3,399,509
Embedded Distributor	kWh	4010	4705	-		935,589	-	$ 0.05833	$ 0.09340	$54,573
Street Light	kWh	4025	4705	-		37,071	832,880	$ 0.05833	$ 0.09340	$79,953
Sentinel Light	kWh	4025	4705	-		95,254	-	$ 0.05833	$ 0.09340	$5,556
USL	kWh	4025	4705	-		29,355	411,726	$ 0.05833	$ 0.09340	$40,167
	kWh	4025	4705	-				$ 0.05833	$ 0.09340	$0
	kWh	4025	4705	-				$ 0.05833	$ 0.09340	$0
	kWh	4025	4705					$ 0.05833	$ 0.09340	$0
	kWh	4025	4705					$ 0.05833	$ 0.09340	$0
TOTAL				**9,226,027**		**53,232,782**	**232,648,373**			**$25,372,580**

Class A - non-RPP Global Adjustment

					2024			
Customer		**Revenue**	**Expense**		**kWh Volume**		**Hist. Avg GA/kWh *** **	**Amount**
GS 50 to 4999 kW		4035	4707		9,226,027		$0.07277	$671,333
Street Lighting		4010	4707		0		0	$0
		4010	4707					$0
		4010	4707					$0
		4010	4707					$0
				-	9,226,027			**$671,333**

Class B - non-RPP Global Adjustment

					2024				
Customer		**Revenue**	**Expense**						Amount
Class Name	UoM	USA #	USA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			2,355,841			$ 0.03904	$91,972
GS < 50	kWh	4010	4707			5,059,452			$ 0.03904	$197,521
GS > 50	kWh	4035	4707			44,720,219			$ 0.03904	$1,745,877
Embedded Distributor	kWh	4010	4707			935,589			$ 0.03904	$36,525
Street Light	kWh	4025	4707			37,071			$ 0.03904	$1,447
Sentinel Light	kWh	4025	4707			95,254			$ 0.03904	$3,719
USL	kWh	4025	4707			29,355			$ 0.03904	$1,146
	kWh	4025	4707			0			$ 0.03904	$0
	kWh	4025	4707			0			$ 0.03904	$0
	kWh	4025	4707			0			$ 0.03904	$0
	kWh	4025	4707			0			$ 0.03904	$0
Total Volume						**53,232,782**				
TOTAL										**$2,078,208**

Appendix 2-4-1 (B) OEB Appendix 2-ZB Cost of Power

Cost of Power Calculation

File Number: EB-2023-0033
Exhibit:
Tab:
Schedule:
Page:
Date: 5/12/23

All Volume should be loss adjusted with the exception of:
1. Volume for Electricity Commodity, Wholesale Market Services, Class A and B should loss adjusted less WMP
2. Low Voltage Charges - No loss adjustment for kWh

		2024 Test Year	RPP		2024 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	187,855,319		17,545,687	2,355,841		137,416	
GS < 50	kWh	40,841,551		3,814,601	5,059,452		295,118	
GS > 50	kWh	2,706,896		252,824	53,946,246		3,146,685	
Embedded Distributor	kWh	0		0	935,589		54,573	
Street Light	kWh	832,880		77,791	37,071		2,162	
Sentinel Light	kWh	0		0	95,254		5,556	
USL	kWh	411,726		38,455	29,355		1,712	
		0		0	0		-	
		0		0	0		-	
		0		0	0		-	
		0		0	0		-	
SUB-TOTAL				21,729,358			3,643,222	$ 25,372,580

Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential - Class B	kWh			0			91,972	
GS < 50 - Class B	kWh			0			197,521	
GS > 50 - Class B	kWh			0			1,745,877	
Embedded Distributor - Class B	kWh			0			36,525	
Street Light - Class B	kWh			0			1,447	
Sentinel Light - Class B	kWh			0			3,719	
USL - Class B				0			1,146	
				0			-	
				0			-	
				0			-	
				0			-	
GS 50 to 4999 kW - Class A				0			671,333	
Street Lighting - Class A				0			-	
				0			-	
				0			-	
				0			-	
SUB-TOTAL				0			2,749,541	$ 2,749,541

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	205,827,497	0.0081	1,661,016	0	0.0081	0	
GS < 50	kWh	49,669,476	0.0073	362,196	0	0.0073	0	
GS > 50	kW	0	2.8691	0	152,108	2.8691	436,413	
Embedded Distributor	kW	0	2.8691	0	2,355	2.8691	6,757	
Street Light	kW	0	2.2341	0	2,623	2.2341	5,860	
Sentinel Light	kW	263	2.2453	590.5139	0	2.2453	0	
USL	kWh	477,294	0.0073	3,480	0	0.0073	0	
							-	
							-	
							-	
							-	
SUB-TOTAL		255,974,530		2,027,282	157,086		449,030	2,476,312

Transmission - Connection								
Class per Load Forecast							$	Total
Residential	kWh	205,827,497	0.0058	1,191,396	0	0.0058	0	
GS < 50	kWh	49,669,476	0.0052	259,792	0	0.0052	0	
GS > 50	kW	0	2.0579	0	152,108	2.0579	313,023	
Embedded Distributor	kW	0	2.0579	0	2,355	2.0579	4,846	
Street Light	kW	0	1.6025	0	2,623	1.6025	4,203	
Sentinel Light	kW	263	1.6105	423.5615	0	1.6105	0	
USL	kWh	477,294	0.0052	2,496	0	0.0052	0	
							-	
							-	
							-	
							-	
SUB-TOTAL		255,974,530		1,454,108	157,086		322,073	1,776,181

Wholesale Market Service								
Class per Load Forecast							$	Total
Residential	kWh	205,827,497	0.0041	843,893	0	0.0041	-	
GS < 50	kWh	49,669,476	0.0041	203,645	0	0.0041	-	
GS > 50	kWh	61,304,365	0.0041	251,348	0	0.0041	-	
Embedded Distributor	kWh	1,012,401	0.0041	4,151	0	0.0041	-	
Street Light	kWh	941,375	0.0041	3,860	0	0.0041	-	
Sentinel Light	kWh	103,074	0.0041	423	0	0.0041	-	
USL	kWh	477,294	0.0041	1,957	0	0.0041	-	
							-	
							-	
							-	
							-	
SUB-TOTAL		319,335,482		1,309,275	0		-	1,309,275

Class A CBR								
Class per Load Forecast							$	Total
Residential	kWh	-	-	-	0	0	-	
GS < 50	kWh	-	-	-	0	0	-	
GS > 50	kWh	0	0.0041	0	0	0.0041	-	

Embedded Distributor	kWh	-		-	0	0	-	
Street Light	kWh	-		-	0	0	-	
Sentinel Light	kWh	-		-	0	0	-	
USL	kWh	-		-	0	0	-	
							-	
							-	
							-	
							-	
SUB-TOTAL		0		0	0		-	-
Class B CBR								
Class per Load Forecast							$	Total
Residential	kWh	205,827,497	0.0004	82,331	0	0.0004	-	
GS < 50	kWh	49,669,476	0.0004	19,868	0	0.0004	-	
GS > 50	kWh	61,304,365	0.0004	24,522	0	0.0004	-	
Embedded Distributor	kWh	1,012,401	0.0004	405	0	0.0004	-	
Street Light	kWh	941,375	0.0004	377	0	0.0004	-	
Sentinel Light	kWh	103,074	0.0004	41	0	0.0004	-	
USL	kWh	477,294	0.0004	191	0	0.0004	-	
							-	
							-	
							-	
							-	
SUB-TOTAL		319,335,482		127,734	0		-	127,734
RRRP								
Class per Load Forecast							$	Total
Residential	kWh	205,827,497	0.0007	144,079	0	0.0007	-	
GS < 50	kWh	49,669,476	0.0007	34,769	0	0.0007	-	
GS > 50	kWh	61,304,365	0.0007	42,913	0	0.0007	-	
Embedded Distributor	kWh	1,012,401	0.0007	709	0	0.0007	-	
Street Light	kWh	941,375	0.0007	659	0	0.0007	-	
Sentinel Light	kWh	103,074	0.0007	72	0	0.0007	-	
USL	kWh	477,294	0.0007	334	0	0.0007	-	
							-	
							-	
							-	
							-	
SUB-TOTAL		319,335,482		223,535	0		-	223,535
Low Voltage - No TLF adjustment								
Class per Load Forecast							$	Total
Residential	kWh	190,211,161	0.0042	804,958	0	0.0042	-	
GS < 50	kWh	45,901,003	0.0038	175,526	0	0.0038	-	
GS > 50	kW	0	1.5046	0	152,108	1.5046	228,857	
Embedded Distributor	kW	0	1.5046	0	2,355	1.5046	3,543	
Street Light	kW	0	1.1716	0	2,623	1.1716	3,073	
Sentinel Light	kW	263	1.1774	310	0	1.1774	-	
USL	kWh	441,081	0.0038	1,687	0	0.0038	-	
							-	
							-	
							-	
							-	
SUB-TOTAL		236,553,508		982,481	157,086		235,474	1,217,954
Smart Meter Entity Charge								
Class per Load Forecast							$	Total
Residential		19,957	0.42	100,582	-	0.42	-	
GS < 50		1,324	0.42	6,672	-	0.42	-	
				-			-	
							-	
							-	
							-	
							-	
							-	
SUB-TOTAL				107,254			-	107,254
SUB- TOTAL				31,604,250			3,756,117	35,360,366
OER CREDIT	11.70%			-3,697,697			0	(3,697,697)
TOTAL				**27,689,022**			**3,756,117**	**31,662,669**

3. The OER Credit of 17% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.
4. Class A CBR: use the average CBR per kWh, similar to how the Class A GA cost is calculated

2024 Test Year - Cop	
4705 -Power Purchased	$ 25,372,580
4707- Global Adjustment	$ 2,749,541
4708-Charges-WMS	$ 1,660,545
4714-Charges-NW	$ 2,476,312
4716-Charges-CN	$ 1,776,181
4750-Charges-LV	$ 1,217,954
4751-IESO SME	$ 107,254
Misc A/R or A/P	$ (3,697,697)
TOTAL	**$ 31,662,669**

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Appendix 2-5-2 (A) OEB Appendix 2-AA Capital Projects

Appendix 2-AA
Capital Projects Table

Net Capital/Gross Capital: Gross Capital

Projects	2017	2018	2019	2020	2021	2022	2023 Bridge Year	2024 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
SYSTEM ACCESS								
IPCSA - 100% RECOVERABLE	639,677	537,174	2,557,620	3,720,847	3,825,445	3,372,856	20,558,688	17,823,100
IPCSA02 - ROAD AUTHORITY WORKS	206,056	812,311	2,430,490	1,382,677	3,032,942	216,038	875,000	2,500,000
IPCSA05 - METERING	400,245	263,953	155,727	687,480	200,774	216,142	524,282	500,000
SUBDIVISIONS	276,704	482,472	25,476	1,848,670	1,885,931	51,248	3,456,666	2,587,248
System Access Total Expenditures	1,522,681	2,095,910	5,169,312	7,639,675	8,945,092	3,856,284	25,414,636	23,410,348
System Access Capital Contributions	979,574	1,359,844	3,865,228	5,774,047	7,191,127	3,277,849	23,920,297	21,160,349
System Access Net Expenditures	543,107	736,066	1,304,084	1,865,627	1,753,965	578,436	1,494,339	2,250,000
SYSTEM RENEWAL								
IPCSR01 - CAPITAL TROUBLE CALLS	326,745	1,116,756	319,844	731,807	612,529	817,073	348,000	358,336
IPCSR02 - TRANSFORMER REPLACEMENT PROGRAM	448,238	219,328	553,954	314,264	425,436	269,438	149,500	157,000
IPCSR03 - POLE REPLACEMENT PROGRAM	1,660,117	355,831	382,767	752,443	546,107	1,130,416	360,000	363,000
IPCSR04 - RECLOSURE REPLACEMENT PROGRAM	0	0	44,385	0	28,165	153,229	182,000	200,200
IPCSR05 - SWITCH REPLACEMENT PROGRAM	0	51,851	0	80,463	116,657	3,697	151,021	166,123
IPCSR06 - SWITCHGEAR REPLACEMENT PROGRAM	0	0	32,980	0	59,911	56,818	21,515	105,525
IPCSR07 - VOLTAGE REGULATORS	0	0	0	0	0	0	160,000	0
IPCSR08 - DELTA/SUBSTANDARD TRANSFORMER REPLACEMENT	118,179	162,191	87,021	102,185	0	32,582	69,500	26,975
IPCSR13 - ANIMAL MITIGATION	0	0	0	0	0	0	50,000	52,250
IPCSR14 - OIL RE-INHIBIT TREATMENT	0	1,593	74,499	24,910	0	0	52,505	0
IPC2018SR13 - METROLINX ELECTRIFICATION PROJECT	0	0	0	0	9,030	5,579,081	8,450,000	0
System Renewal Total Expenditures	2,553,278	1,907,550	1,495,449	2,006,072	1,797,835	8,042,335	9,994,041	1,429,409
System Renewal Capital Contributions	0	0	110,770	155,522	174,285	5,718,609	8,250,000	0
System Renewal Net Expenditures	2,553,278	1,907,550	1,384,680	1,850,550	1,623,550	2,323,726	1,744,041	1,429,409
SYSTEM SERVICE								
IPCSS05 - 27.6kV OH DIST FAULT INDICATORS	0	0	31,072	14,473	5,900	0	48,617	0
IPCSS06 - 44kV OH DIST FAULT INDICATORS	0	0	7,291	15,136	0	0	47,217	0
IPCSS07 - 44kV SWITCH COMMISSIONING	0	0	0	0	0	72,324	118,608	0
IPCSS08 - COMMUNICATION IMPROVEMENT	0	0	0	16,298	271,883	0	0	77,500
IPCSS10 - H1 TRANSMISSION LINE EXTENSION TO INNPOWER TS	0	0	0	0	0	0	0	0
IPCSS11 - INNPOWER TS	0	0	0	0	0	0	1,350,158	0
IPCSS12 - STATION REHAB	21,073	275,841	2,193,999	2,682,917	2,029,969	392,703	4,979,165	3,100,000
IPCSS17 - BARRIE AREA TRANSFORMER UPGRADE (BATU)	0	0	0	0	0	0	4,099,270	4,120,000
IPCSS18 - 44kV LINE EXTENSION FROM BARRIE	0	0	0	0	0	0	1,020,730	0
IPCSS21 - SCADAMATE / VIPER COMMISSIONING	0	0	40,600	8,014	104,664	38,299	101,750	0
IPCSS24 - NORMAL OPEN POINT SWITCH INSTALLATION	0	0	0	0	0	0	201,000	221,100
System Service Total Expenditures	21,073	275,841	2,272,962	2,736,838	2,412,416	503,327	11,966,515	7,518,600
System Service Capital Contributions	0	0	2,456,655	2,606,513	16,549	0	4,875,278	3,100,000
System Service Net Expenditures	21,073	275,841	-183,693	130,325	2,395,867	503,327	7,091,237	4,418,600
GENERAL PLANT								
IPCGP01 - IT HARDWARE	134,688	45,779	45,304	135,658	24,956	84,647	79,600	194,303
IPCGP02 - IT SOFTWARE	50,646	13,955	60,517	118,459	59,707	85,165	126,300	125,000
IPCGP03 - FURNITURE & EQUIPMENT	6,246	0	39,714	5,438	23,353	0	0	0
IPCGP04 - BUILDING & FIXTURES	71,055	196,384	38,914	75,630	43,734	143,855	75,000	75,000
IPCGP05 - FINANCE IT	44,058	42,527	53,053	121,648	92,938	100,656	200,000	40,000
IPCGP06 - ENGINEERING IT	2,963	253,347	1,288	155,755	247,140	454,497	119,640	35,000
IPCGP07 - MEASUREMENT & TESTING EQUIPMENT	33,848	22,464	5,225	0	2,290	2,425	0	0
IPCGP10 - TOOLS, SHOP & GARAGE EQUIPMENT	5,007	0	28,693	17,941	74,701	53,427	78,750	82,688
IPCGP12 - FLEET	14,782	572,636	0	18,630	657,956	45,802	475,690	470,000
General Plant Total Expenditures	363,292	1,147,091	272,708	649,159	1,226,774	970,473	1,154,980	1,021,991
General Plant Capital Contributions	0	0	0	9,075	0	0	0	0
General Plant Net Expenditures	363,292	1,147,091	272,708	640,084	1,226,774	970,473	1,154,980	1,021,991
Miscellaneous								
Total	**3,480,751**	**4,066,548**	**2,777,779**	**4,486,586**	**7,000,156**	**4,375,962**	**11,484,597**	**9,120,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*	0	0	0	0	0	0	0	0
Total	**3,480,751**	**4,066,548**	**2,777,779**	**4,486,586**	**7,000,156**	**4,375,962**	**11,484,597**	**9,120,000**

Appendix 2-5-2 (B) OEB Appendix 2-AB Capital Expenditures

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2024

CATEGORY	Historical Period (previous plan[1] & actual)																						Forecast Period (planned)				
	2017			2018			2019			2020			2021			2022			2023			2024	2025	2026	2027	2028
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	3,509	1,523	-130.4%	13,778	2,096	-557.5%	11,682	5,169	-126.0%	12,103	7,640	-58.4%	13,192	8,945	-47.5%		3,856	100.0%	25,415		-100.0%	23,410	17,381	9,584	8,624	8,875
System Renewal	1,348	2,553	47.2%	1,142	1,908	40.1%	3,326	1,495	-122.4%	2,862	2,006	-42.7%	2,577	1,798	-43.3%		8,042	100.0%	9,994		-100.0%	1,429	1,593	1,633	1,674	1,716
System Service	248	21	-1081.0%	660	276	-139.1%	393	2,273	82.7%	534	2,737	80.5%	422	2,412	82.5%		503	100.0%	11,967		-100.0%	7,519	9,374	4,902	5,207	32,417
General Plant	1,168	363	-221.8%	1,423	1,147	-24.1%	962	273	-252.4%	745	649	-14.8%	706	1,227	42.5%		970	100.0%	1,155		-100.0%	1,022	730	803	821	1,035
TOTAL EXPENDITURE	6,274	4,460	-40.7%	17,003	5,426	-213.4%	16,362	9,210	-77.7%	16,244	13,032	-24.6%	16,897	14,382	-17.5%	-	13,372	100.0%	48,530	-	-100.0%	33,380	29,078	16,922	16,326	44,043
Capital Contributions	- 1,869	- 980	-90.7%	- 11,826	- 1,360	-769.6%	- 9,928	- 6,433	-54.3%	- 10,450	- 8,545	-22.3%	- 11,129	- 7,382	-50.8%		- 8,996	100.0%	- 37,046		-100.0%	- 24,260	- 19,898	- 7,669	- 6,997	- 7,247
NET CAPITAL EXPENDITURES	4,405	3,481	-26.5%	5,176	4,066	-27.3%	6,434	2,778	-131.6%	5,794	4,487	-29.1%	5,768	7,000	17.6%		4,376	100.0%	11,485		-100.0%	9,120	9,180	9,253	9,328	36,797
System O&M	$ 2,179	$ 2,217	1.7%	$ 2,245	$ 2,029	-10.6%	$ 2,246	$ 1,966	-14.2%	$ 2,246	$ 1,867	-20.3%	$ 2,246	$ 2,598	13.5%		$ 2,318	100.0%	$ 2,622		-100.0%	$ 3,091	$ 3,307	$ 3,406	$ 3,508	$ 3,614

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

3. System O&M contains the following accounts: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096, 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 5195

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories
Variances are provided in the Distribution System Plan in Exhibit 2.

Appendix 2-5-3 InnPower Distribution System Plan



InnPower Corporation

Distribution System Plan

2024 Cost of Service Application

Historical Period:

2017–2023 (2023 Bridge Year)

Forecast Period:

2024–2028

Date

Mar 31, 2023

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LIST OF ACRONYMS

Acronym	Meaning
AC	Alternating Current
ACA	Asset Condition Assessment
ADMS	Advanced Data Management System
AHSIP	Accelerated High-Speed Internet Program
AM	Asset Management
BATU	Barrie Area Transformer Upgrade
CAIDI	Customer Average Interruption Duration Index
CDM	Conservation Demand Management
CEP	Community Energy Plan
CHEC	Cornerstone Hydro Electric Concepts Association
CHI	Customer Hours Interrupted
CI	Customers Interrupted
CIA	Connection Impact Assessment
CoS	Cost of Service
CSA	Canadian Standards Association
CT	Current Transformer
CVOR	Commercial Vehicles Operators Registration
DAI	Data Availability Indicator
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DESN	Dual Element Spot Network
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DS	Distribution Station
DSC	Distribution System Code
DSP	Distribution System Plan
EA	Environmental Assessment
EDA	Electricity Distributors Association
EOL	End of Life
ESA	Electrical Safety Authority
FEI	Framework for Energy Innovation
FLISR	Fault Location, Isolation, and Service Restoration
FTE	Full Time Employee
GIS	Geographic Information System
GIS-UNM	Geographic Information System Utility Network Model

Acronym	Meaning
HI	Health Index
HONI	Hydro One Networks Inc.
HSE	Health, Safety and Environmental
ICM	Incremental Capital Module
IESO	Independent Electricity System Operator
Innisfil Hydro	Innisfil Hydro Distribution Systems Limited
InnPower	InnPower Corporation
IR Scan	Infrared Scan
IRRP	Integration Regional Resource Plan
IT	Information Technology
LDC	Local Distribution Company
LOS	Loss of Supply
LTR	Limited Time Rating
M&R	Maintenance and Repair
MCR	Municipal Comprehensive Review
MEARIE	Municipal Electrical Association Reciprocal Insurance Exchange
MED	Major Event Day
METSCO	METSCO Energy Solutions Inc.
MOE	Ministry of Energy
MTO	Ministry of Transportation
NA	Needs Assessment
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OH	Overhead
OM&A	Operating, Maintenance, and Administration
OMS	Outage Management System
PCB	Polychlorinated Biphenyl
POE	Power Over Ethernet
RBD	Radial Boom Derrick
REG	Renewable Energy Generation
RFP	Request for Proposal
RIP	Regional Infrastructure Plan
ROE	Return on Equity
ROW	Right of Way
RPPAG	Regional Planning Process Advisory Group
RRF	Renewed Regulatory Framework
RVH	Royal Victoria Hospital

Acronym	Meaning
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQR	Service Quality Requirements
TS	Transformer Station
TUL	Typical Useful Life
UCCWG	Utilities Climate Change Working Group
UG	Underground
USF	Utilities Standards Forum
VLF	Very Low Frequency
WIP	Work in Progress

5.2 DISTRIBUTION SYSTEM PLAN

Distributors are encouraged to organize the required information using the section and subsection headings indicated from here onwards.

The DSP's duration is a minimum of ten years in total, comprising of a historical period and a forecast period. The historical period refers to the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost of service application to the bridge year. The forecast period refers to the last five years of the DSP duration, consisting of five forecast years, beginning with the test year of the current cost of service application.

InnPower has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) Chapter 5: Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications, 2023 Edition for 2024 Rate Applications, dated December 15, 2022 (the "Filing Requirements") as part of its 2024 Cost of Service (CoS) Application (the Application). InnPower retained METSCO Energy Solutions Inc. (METSCO) to advise on and assist with the preparation of the DSP.

The DSP is a standalone document that is filed in support of InnPower's Application. The DSP's duration is a minimum of ten years in total, comprising of a historical period and a forecast period. This DSP covers the historical period of 2017 to 2023, with 2023 being the bridge year[1], and a forecast period of 2024 to 2028, with 2024 being the Test Year.

The DSP contents are organized into three major sections:

- Section 5.2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement.
- Section 5.3 provides an overview of Asset Management (AM) practices, including an overview of the assets managed and asset lifecycle optimization policies and practices.
- Section 5.4 provides a summary of the capital expenditure plan. It includes a variance analysis of historical expenditures, an analysis of forecast expenditures, and justification of material projects above the materiality threshold.

The materiality threshold for InnPower is $73,000, and detailed descriptions of specific projects and programs exceeding the materiality threshold are provided in Section 5.4.2.1 and Appendix A. Other pertinent information relevant to this DSP is included in the Appendices.

This DSP follows the chapter and section headings in accordance with the Chapter 5: Filing Requirements.

[1] **NOTE:** 2022 was the original bridge year but was deferred to 2023 following the OEB's approval of InnPower's request to defer the rebasing of its rates to the 2024 rate year.

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

The distributor must provide a high-level overview of the information filed in the DSP and is encouraged not to unnecessarily repeat details contained in the rest of the DSP. The overview should include capital investment highlights and changes since the last DSP. A distributor should list out the objectives it plans to achieve through this DSP, which will be used as a baseline comparison in the performance measurement section below. This DSP will inform and potentially support any requests for Incremental Capital Module (ICM) funding during the five-year DSP term.

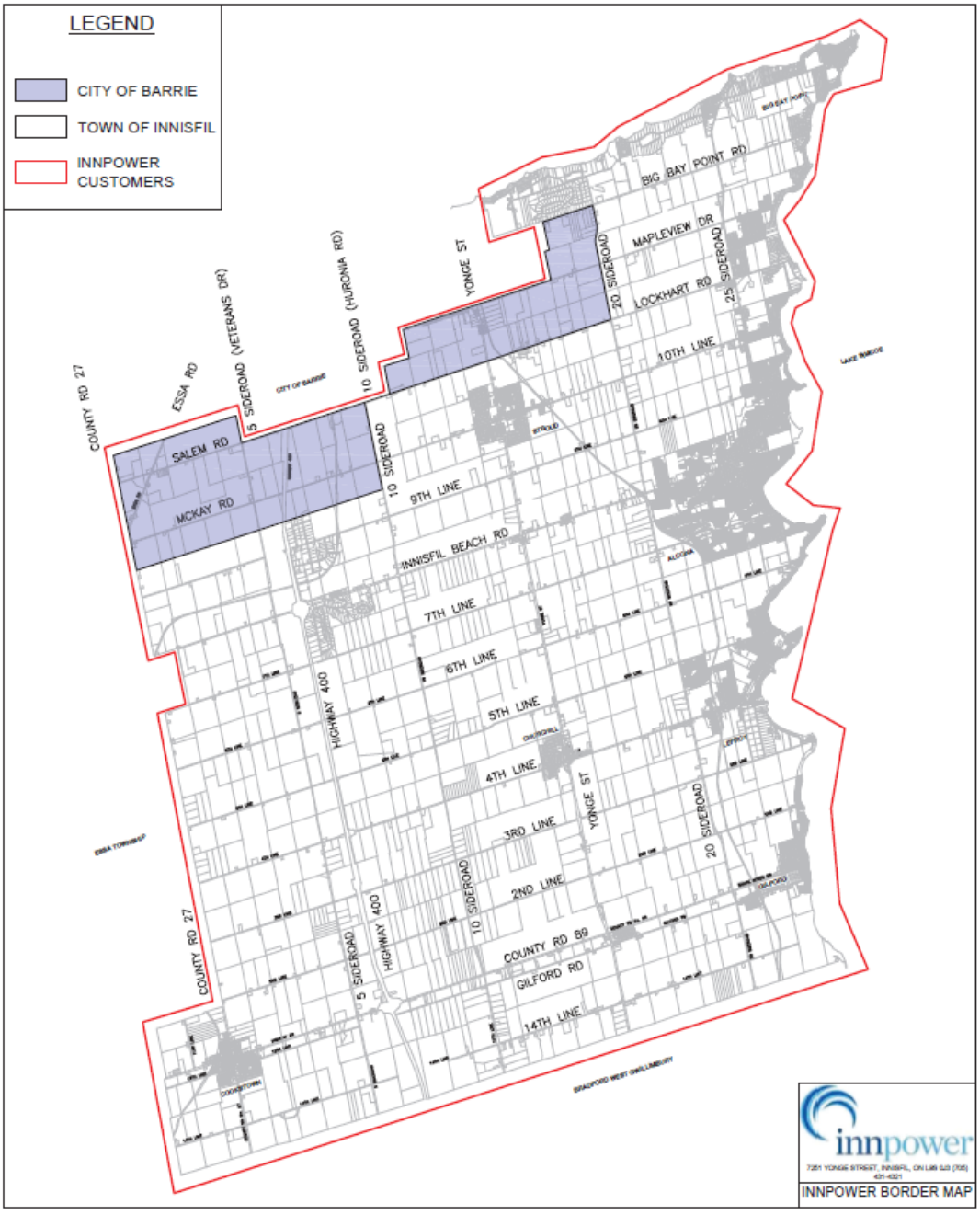
5.2.1.1 Description of the Utility Company

The Hydro Electric Commission of the Corporation of the Town of Innisfil was created in January 1991 as provided for in *Bill 177, 1990*. It continued to serve only the former Village of Cookstown until 1993, when the distribution assets in the remainder of the newly incorporated Town of Innisfil were purchased from Ontario Hydro. Innisfil Hydro Distribution Systems Limited (Innisfil Hydro) was incorporated as a for-profit Local Distribution Company (LDC) in 2000 as required by the *Electricity Act, 1998*. In January 2015, Innisfil Hydro changed its name to InnPower Corporation.

InnPower is a member of the Cornerstone Hydro Electric Concepts Association (CHEC), a cooperative that provides shared resources and encourages collaboration between its 15 LDC members representing more than 100,000 customers. InnPower has access to a common set of design, construction, and material standards, as per its membership with Utilities Standards Forum (USF). InnPower is also an active member of the Electricity Distributors Association (EDA), the Utility Advisory Council at the Electrical Safety Authority (ESA), and the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) Group.

InnPower is among the fastest growing utilities in Ontario, presently serving over 20,000 customers within a service area of 292 square kilometres (the same size as Mississauga). The *Barrie-Innisfil Boundary Adjustment Act, 2009* granted the City of Barrie approximately 2,300 hectares of land within the former boundaries of the Town of Innisfil for development. This land falls within InnPower's service territory. As such, InnPower's service territory encompasses the lands of South Barrie and all of the Town of Innisfil, which includes the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. InnPower's service territory is depicted in Figure 5.2-1.

Figure 5.2-1: InnPower's Service Territory



InnPower's 2023 organizational chart is illustrated in Figure 5.2-2. The chart is inclusive of the InnPower's contracted services, current and new employees. The chart depicts the addition of eight new Full Time Employees (FTEs) to help manage the rapid growth and help achieve the company's objectives. The chart also depicts InnPower's commitment to work with its utility affiliates to use contracted services (shown in purple) to provide for continued collaboration and cost savings for ratepayers.

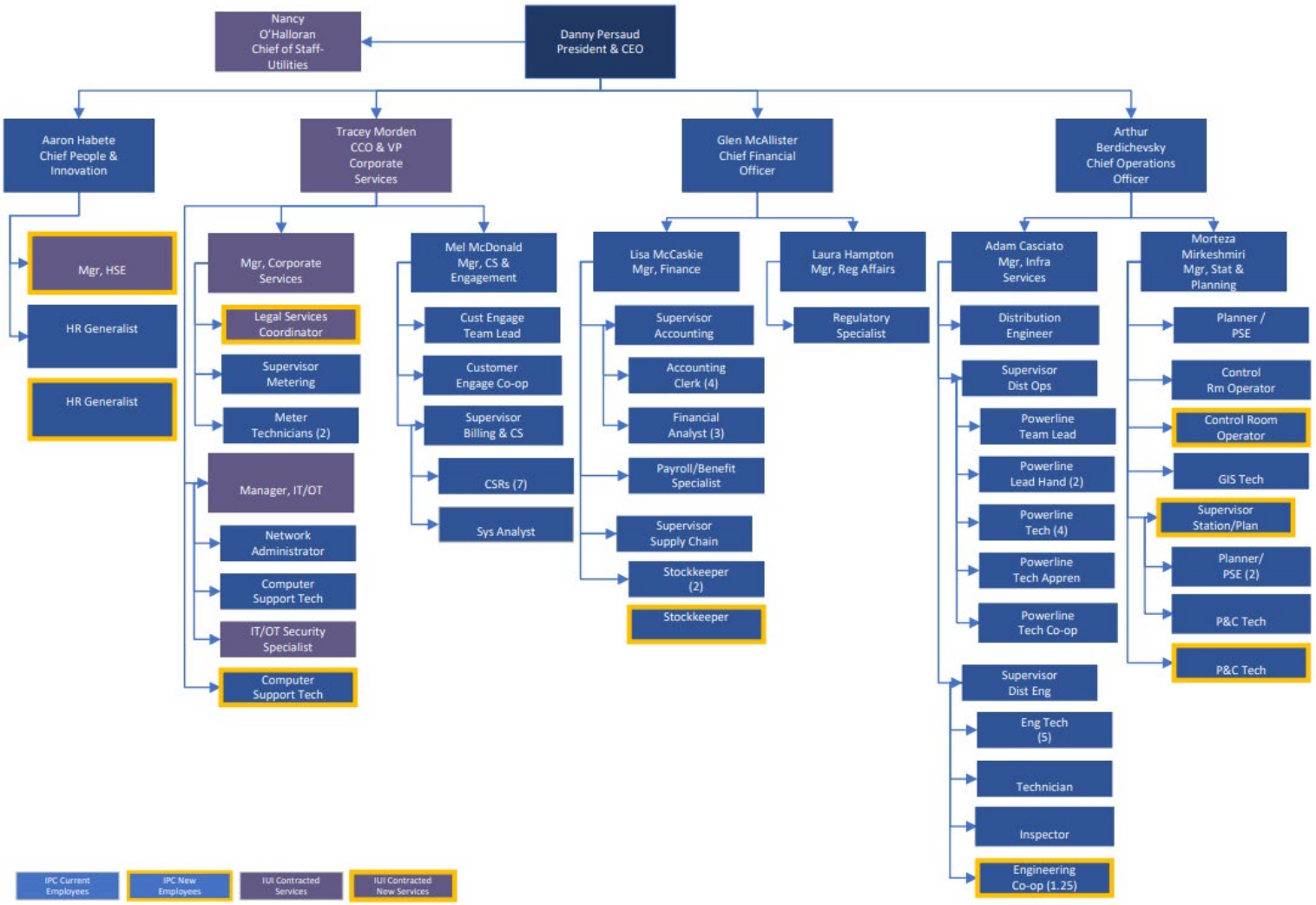


Figure 5.2-2: InnPower's 2023 Organizational Chart

InnPower is driven by its corporate vision, mission, and core values. Together, they provide the basis to deliver on targeted strategic goals and performance objectives.

Mission: InnPower's mission statement is "*to deliver the energy our communities depend on to grow and prosper, with a commitment to safety and reliability, and a passion for value-added services to our customers, employees and* shareholder."

Vision: InnPower's vision is "*to be one of Canada's Most Innovative Utilities, committed to boldly leading change, and achieving maximum value for our stakeholders*."

Core Values: InnPower's core values include:

- Health, Safety and Environmental (HSE) Stewardship.
- Innovation and Sustainability.
- Fiscal prudence.
- Fostering a Collaborative and Respectful Culture.
- Community Leadership and Presence.

Corporate Strategic Goals:

In accordance with its Five-Year Strategic Plan, InnPower will focus on eight strategic priorities over the next five years. These priorities, which are highlighted below, have been found to be integral to an effectively managed utility. Additional information on these strategic priorities can be found in Section 12 of the *InnPower Corporation Strategic Plan for 2023 to 2027*, attached as Exhibit 1-1-5 to this Cost-of-Service application.

- **Service Quality and Safety:** We will foster a culture that understands and respects that *quality*, *reliability*, and *safety* are paramount to the utility's success.
- **Enterprise Resiliency:** We will create a cohesive work environment where utility leadership and staff work together internally and with external organizations to anticipate, respond to and avoid large-scale issues and emerging threats.
- **Operational Optimization:** We will foster a culture that embraces working together in a continuous quest for efficiencies and is encouraged and supported in a quest for sustainable *"outside of the box"* ideas to improve our business.
- **Financial Viability:** We will develop sustainable strategies that allow the utility to meet its growth objectives, reduce risks and provide a strong, healthy return to the shareholder and community.
- **Employee Development and Engagement:** We will promote InnPower as a growing, collaborative organization that thrives on diversity, *"outside of the box"* thinking, and is committed to learning, development, advancement, safety, trust, and respect.
- **Customer Satisfaction and Engagement:** We will create a strong customer service team committed to providing the best customer experience possible with a first contact resolution.
- **Stakeholder Understanding and Support:** We will foster strong relationships with external stakeholders to educate and receive feedback to be incorporated into the organization's decisions.
- **Infrastructure Strategy and Performance:** We will drive excellence in sustainable design and efficiency through proactive management of critical infrastructure assets.

5.2.1.2 Capital Investment Highlights

The overview should include capital investment highlights.

InnPower's capital investments over the planning period have been aligned with the four categories of System Access, System Renewal, System Service, and General Plant outlined in the Filing Requirements. Table 5.2-1 presents InnPower's historical actuals and forecast expenditures for capital and Operations and Maintenance (O&M) categories.

Table 5.2-1: Historical and Forecast Capital Expenditures and System O&M ($ '000)

Category	Historical						Bridge	Forecast				
	2017	2018	2019	2020	2021	2022	2023[1]	2024	2025	2026	2027	2028
System Access (gross)	1,523	2,096	5,169	7,640	8,945	3,856	25,415	23,410	17,381	9,584	8,624	8,875
System Renewal (gross)	2,553	1,908	1,495	2,006	1,798	8,042	9,994	1,429	1,593	1,633	1,674	1,716
System Service (gross)[2]	21	276	2,273	2,737	2,412	503	11,967	7,519	9,374	4,902	5,207	32,417
General Plant (gross)	363	1,147	273	649	1,227	970	1,155	1,022	730	803	821	1,035
Gross Capital Expenses[3]	4,460	**5,426**	**9,210**	**13,032**	**14,382**	**13,372**	**48,530**	**33,380**	**29,078**	**16,922**	**16,326**	**44,043**
Contributed Capital	(980)	(1,360)	(6,433)	(8,545)	(7,382)	(8,996)	(37,046)	(24,260)	(19,898)	(7,669)	(6,997)	(7,247)
Net Capital Expenses after Contributions[3]	3,481	4,066	2,778	4,487	7,000	4,376	11,485	9,120	9,180	9,253	9,328	36,797
System O&M	2,217	2,029	1,966	1,867	2,598	2,318	2,622	3,091	3,307	3,406	3,508	3,614

[1] 0 months of actual expenditures included in 2023.
[2] The System Service spending over the 2023–2028 period includes InnPower's capital contributions towards the BATU project and costs relating to InnPower's new TS Project. Both projects are detailed further in Section 5.2.1.2.3 below.
[3] Numbers may not add up due to rounding.

Load growth is primarily driven by new residential, commercial, and industrial development. There is significant future growth projected within InnPower's service area. Growth generates both challenges and opportunities for InnPower as the ongoing needs of existing ratepayers are balanced with the pressures associated with growth and the incremental increases in costs for operational needs. When the need to address longer-term financial requirements related to asset renewal and replacement are also taken into consideration, it is evident that careful and prudent planning is necessary to ensure that InnPower remains stable, sustainable, and affordable for all ratepayers. InnPower's capital plan over the forecast period will enable InnPower to prudently construct, maintain, and upgrade its distribution infrastructure to meet future growth demands. A brief description of the mix of capital investments by investment category over the forecast period are provided below.

5.2.1.2.1 System Access

Capital investments in the System Access category over the forecast period are driven by customer service requests, third-party infrastructure development requirements, and mandated service obligations. System Access investments over the forecast period include new subdivisions and line relocation projects, customer connections, and metering projects. The timing of investment is driven by the needs of the external parties. These expenditures are mandatory. Specific project scopes are rarely known at the time that the budget is set, and total expenditures can vary from year to year.

For the forecast period, InnPower's System Access forecast expenditure is increasing which is primarily due to some known customer growth areas in InnPower's service territory. Some of the key drivers, which are detailed more in Section 5.4.1.2.1 are:

- An increase in large subdivision development involving servicing lots to accommodate these new subdivisions.
- An increase in road authority driven works which involve OH and/or UG lines relocations to accommodate road widening projects driven municipalities and the MTO.

5.2.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of station and distribution system assets and play a crucial role in the overall reliability, safety, and sustainment of the distribution system. InnPower's Asset Condition Assessment (ACA), which was completed in October 2021, recommends assets for renewal based on condition data from maintenance, testing, inspections, and infrared scanning records. InnPower's AM process detailed in Section 5.3 of this DSP outlines the strategy used to determine the criteria for asset replacement. The output of the AM process drives the development of the capital expenditure plan and prioritization for System Renewal. Over the forecast period of the DSP, several annual System Renewal programs are budgeted each year to address the need to replace assets at the end of their service life, including pole replacements, transformer replacements, reclosure replacements, switch replacements, and switchgear replacements.

In addition to InnPower's annual renewal programs, unplanned System Renewal projects are also budgeted each year to allow for the replacement of electrical infrastructure damaged by inclement weather or unclaimed vehicle accidents.

5.2.1.2.3 System Service

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility, and distributed energy resource (DER) integration) while addressing anticipated future customer electricity service requirements (i.e.: station capacity increases, feeder extension, etc.). The investments comprising the System Service expenditures include station rehabilitation projects as well as several switch installations, and commissioning projects, installation of fault indicators, protection and control devices and communication improvements.

Over the forecast period, two projects in particular are driving a significant shift in capital spending under the System Service investment category to accommodate load growth and grid modernization initiatives. This includes the BATU project and the construction of a new Transformer Station (TS).

BATU Project

The BATU project consists of upgrading two existing 115 kV circuits to 230 kV between Essa TS and Barrie TS, constructing new 230 kV connection points at the Essa TS, and upgrading and expanding

the existing Barrie TS with new 230–44 kV facilities. The transmission line and station work are required to increase supply capacity to accommodate customer load growth in South Barrie and Innisfil areas and to address immediate end-of-life issues with the current facilities.

The BATU project was approved by the OEB in April 2020[2] and is currently being constructed by Hydro One Networks Inc. (HONI). As part of this project, it was agreed that InnPower would make capital contribution installment payments to HONI for the incremental costs relative to the cost of the avoided sustainment work that HONI was originally planning to undertake on these facilities. At the time of the OEB decision, the total cost estimate of the BATU project was $91M, and InnPower's total capital contribution was set at $14.1M with a repayment schedule of five years, starting in the year the asset goes into service. As of April 2022, the total cost of the BATU project is expected to be $125M, and as a result, InnPower's total capital contribution has been increased from $14.1M to $20.6M. The capital contribution associated with this project alone accounts for approximately 82% of InnPower's proposed net System Service costs over the 2024-2028 forecast period. Additional information on the BATU project, including reasons for the project delays and cost increases, is included in Section 5.4.1.2.

With respect to the other supply work related to BATU, InnPower is working with Hydro One Distribution to relocate its existing supply feeder from Barrie TS and provide an additional feeder from Barrie TS to serve InnPower's mid-term needs. The current anticipated timeframe for the BATU upgrade to go into service is the end of 2023. InnPower's capital contribution for this work is estimated at $1.02M in the 2023 bridge year. A breakdown of the costs associated with this project is included in Table 5.22.

Table 5.2-2: BATU Project Cost Details ($ '000)

BATU Project Component Details	Bridge	Forecast					Total
	2023	2024	2025	2026	2027	2028	
(IPCSS17) BATU	4,099	4,120	4,120	4,120	4,120	-	20,579
(IPCSS18) 44kV Line Extension from Barrie	1,021	-	-	-	-	-	1,021

New TS Project

InnPower is among the fastest growing utilities in Ontario and has an immediate supply constraint to meet its mid and long-term needs due to this customer growth—particularly due to the developments in South Barrie.

As noted above, the ongoing BATU project and other supply work related to BATU are expected to serve InnPower's mid-term needs. However, to meet the long-term needs, InnPower is planning to work with Hydro One Transmission to extend the double circuit 230 kV transmission into Innisfil and build a new 230/27.6kV 2x83MVA Dual Element Spot Network (DESN) transformer station (TS Project) to accommodate the increased supply capacity needs identified while also allowing for future load growth beyond the forecast period. This solution builds upon the BATU project design as the new TS will connect to the new 230 kV transmission lines that will be available post-completion of the BATU project. In coordination with Hydro One Transmission, it was determined that InnPower would be

[2] OEB Decision and Order: Hydro One Networks Inc. Application for Leave to Upgrade Existing Transmission Line Facilities in the Barrie-Innisfil Area. EB-2018-0117. April 23, 2020.

responsible for constructing the new TS and Hydro One Transmission would construct the transmission line expansion.

A three-acre property was purchased in 2012 and an Environmental Assessment (EA) is currently underway to determine the feasibility for this property as the site of the TS. The new TS is planned to be energized near the end of the forecast period, either in the year 2027/28 or potentially beyond (i.e.: InnPower is monitoring load behavior and will defer the need for this project as much as possible). The TS Project capital spending over the bridge and five-year forecast period will remain in Work in Progress (WIP) and will be addressed in InnPower's next rebasing application once the TS is energized. A breakdown of the costs associated with this project is included in Table 5.23.

Table 5.2-3: TS Project Cost Details ($ '000)

TS Project Component Details	Bridge	Forecast					Total in WIP
	2023	2024	2025	2026	2027	2028	
(IPCSS11) InnPower TS	1,350	-	-	-	-	23,314	24,664
(IPCSS10) H1 Transmission Line Extension to InnPower TS	-	-	-	-	-	8,220	8,220

5.2.1.2.4 General Plant

General Plant expenditures are driven by the need to modify, replace or add to assets not part of the distribution system but support InnPower's ongoing operations (i.e: land, buildings, fleet, tools, and equipment, rolling stock and electronic devices and operational software). InnPower's expenditures under this category include ongoing investments in IT hardware and software, process improvements, ongoing improvements to buildings and fixtures, a bucket truck replacement, and investments in miscellaneous tools and equipment.

5.2.1.3 Key Changes since Last DSP Filing

The overview should include changes since the last DSP.

Over the last five years, InnPower has implemented several enhancements and evolutionary changes to support the business. A few of the more notable changes since the last DSP filing includes:

- **New Strategic Plan:** Since the 2017 DSP, InnPower has developed and implemented a new strategic plan, which includes an updated company mission, vision, core values and strategic objectives. The plan, which is entitled *InnPower Corporation Strategic Plan for years 2023 to 2027,* can be found in Exhibit 1-1-5 of the 2024 Cost-of-Service application.
- **New Operational Processes and Supporting Systems:** InnPower is among the fastest growing utilities in Ontario, and transitioning from a less-dense rural utility to a more-dense rural utility has driven several improvement initiatives within InnPower, especially with respect to the development of clear, defined, and sustainable operational processes and supporting systems. These operational processes and supporting systems aim to meet the needs of both new and existing customers. A few key examples are noted below, and additional examples and details can be found in the *InnPower Corporation Strategic Plan for years 2023 to 2027:*
  - **Prophix Financial Software:** Over the last five years, InnPower has invested in a powerful financial business intelligence software, *"Prophix,"* which is used across the company to provide real-time reporting and inform major financial decisions. Prophix is used to enter and

track budgets, create long-term plans, generate real-time reports and more, which created several efficiencies in data entry and reduced manual effort. This ultimately resulted in the generation of stronger, defensible business cases with the timeliest information.

- **Geographic Information System (GIS) Upgrade:** InnPower has recently completed the migration from its previous AutoCAD Map 3D GIS to a comprehensive Geographic Information System called Utility Network Model (GIS-UNM). InnPower is among the first utilities in Canada to complete this upgrade. The new GIS-UNM enables bi-directional information flow between the Supervisory Control and Data Acquisition (SCADA) and the GIS and will enable InnPower to perform real-time spatial analysis such as circuit tracing and heat maps. Transitioning to this dynamic, robust, and integrated spatial database will improve the overall business intelligence, decision making process and operational optimization throughout the organization. It also enables connectivity to CYME software for real time short fault analysis and load flow study. As a result of the successful GIS UNM upgrade, InnPower staff now have more visibility into:
  - The progress of each job.
  - The status of all distribution assets owned by InnPower.
  - Improved job planning capabilities.
  - Cost-effective means of pre-engineering design work.
  - Fewer site visits required—further reducing costs.
  - Live simulation of distribution connectivity and asset behaviour.
  - Improved accuracy for Engineering and System Planning work.
  - More sophisticated and detailed data analytics to reduce time and costs for Distribution System Plans and asset maintenance programs.
  - More accessible export/import process to get GIS data into the Outage Management System (OMS) and CYME.
  - Increased reliability and Control Room operator confidence in SCADA data.
- **Cyber Security Framework:** InnPower has made strides on its Cyber Security Framework since its inception in 2018. InnPower, in collaboration with a third-party vendor, has commenced the implementation of real-time monitoring and patch programs as required. InnPower has also worked collaboratively with its industry affiliate USF to create recovery plans that align with the framework. InnPower is presently undertaking a restructuring of its IT department and IT infrastructure. As part of the restructuring, InnPower will be implementing a new comprehensive cyber security program including, but not limited to, updated servers, software, staff training and education, protocols, and procedures. As part of the comprehensive program, InnPower will diversify its IT infrastructure assets and take a multi-avenue approach to Cyber Security. This approach will allow InnPower to ensure that the most current versions of software and updated hardware are used. It will also provide InnPower with mechanisms for risk identification and classification to ensure appropriate countermeasures, redundancies, and contingency plans are in place.
- **3CX Phone System:** InnPower implemented a digital phone system in November 2021. This new phone system has increased the number of available lines for customer calls from four to twenty, which has improved communications during storms and outages. The new phone

system also provides better internal reporting/metrics, improves ease of use for staff, and allows staff to work and answer phones from any location with an internet source.

- **Climate Change and Resiliency:** InnPower is participating in a Utilities Climate Change Working Group to discuss and recommend practical solutions to adaptation and mitigation of climate change. This group consists of InnPower, InnServices and the Town. In response to more extreme climate change events, and as identified in the OEB's Resilience in the Electricity Distribution Sector Report, InnPower is undertaking several measures to make its system more resilient as outlined below:
  - Improved Vegetation Management in order to avoid trees and/or debris falling on the pole lines.
  - Assigning additional resources on standby when there are inclement weather alerts.
  - Using technical staff for power restoration to triage potential damage and to locate the root cause of an outage. This allows InnPower to utilize and focus field staff on restoring power and reducing outage locating time(s).
  - Implementing a robust power restoration plan with different levels of escalation.
  - System hardening by improving the design for extreme weather conditions.
  - Increased automation to reduce outage durations and improve reliability.
- **New Strategy to Address Supply Chain Constraints:** Due to significant supply chain issues, especially with regards to the purchase of transformers, InnPower has joined an initiative being led by the Utilities Standards Forum (USF) group to align the standards and specifications around transformers with other utilities facing similar supply chain constraints. This buying group recently sent out a Request for Proposal (RFP) to numerous vendors and is currently in the process of evaluating the submissions. The objective is to find economies of scale in terms of the type of transformers; features of transformers; use a higher number of purchases to gain space in the production line; and determine cost savings in both production and transportation/delivery. Through this process, InnPower can now place an order for single phase transformers in 2023, whereas if InnPower had not participated in this buying group, InnPower would not have the ability to place an order these units.
- **New Strategy for Meeting Capacity Constraints:** Since the last DSP, there has been a change in the proposed strategy for meeting capacity constraints. In the last DSP, InnPower had proposed to build the Friday Harbour DS (10MVA) station to accommodate the loads associated with new developments in Innisfil and South Barrie. When conducting further system planning studies, InnPower identified the system constraint to be at the Hydro One supplied 44 kV sub-transmission level and as a result, determined that the originally proposed Friday Harbour DS solution would not be adequate to meet the load growth. For this reason, InnPower revisited its strategy and determined that it would need to upgrade existing Distribution Stations (DS) to meet the short-term/mid-term demand and invest in building a new 2x83 MVA TS (TS Project) to meet the long-term demand in South Barrie and Innisfil Area. New recoverable distribution expansion projects are also underway to help accommodate future load growth.
- **COVID-19:** As with many businesses over the past couple of years through the COVID-19 pandemic, InnPower's transitioned its employees to working remotely. With many businesses gradually emerging from the COVID-19 pandemic effects, InnPower proposes to continue this working arrangement for its employees for the foreseeable future. If successful, InnPower plans

on exploring options to lease a portion of its operations centre to reduce its facility emissions and provide a revenue offset (operating costs reduction) to utility customers.

- **Internal Scorecard Reporting:** To meet the growing regulatory demands, InnPower has created and started a process of automating (via the Prophix software previously discussed) a monthly internal scorecard reporting process to provide timely, accurate data with which to make quick and prudent decisions.
- **Stronger Digital Strategy:** COVID-19 has had a significant impact on InnPower customer relations and engagement efforts. This has solidified the need to transition to and implement a stronger digital strategy while enhancing InnPower's visibility and reach in the community and improving the overall customer experience. Several improvements are either in place, are currently underway, or are planned to be implemented over the next few years. Examples include converting customer service forms to online forms, upgrading its online customer portal to a fully integrated platform (silver blaze), and adding a live chat feature to InnPower's website. Additional information on these improvements can be found in the *InnPower Corporation Strategic Plan for years 2023 to 2027*.
- **Deferment of Major Projects:** During the last five years, InnPower has continuously re-assessed the need to undertake projects, ensuring that only high-priority projects are carried out. One of the major types of projects InnPower deferred was the need to replace underground cables. This was mainly due to InnPower not observing an increase in failure rate on primary underground cable. It was determined that higher-priority projects should be carried out while continuing to monitor underground cable failure.

5.2.1.4 DSP Objectives

A distributor should list out the objectives it plans to achieve through this DSP.

InnPower's DSP is a stand-alone document that is filed in support of InnPower's CoS Application. The DSP was prepared to provide to the OEB and all interested stakeholders:

- An overview of InnPower's AM objectives and processes.
- An overview of InnPower's managed assets and asset lifecycle optimization practices.
- An overview of InnPower's coordinated planning and engagement with third parties.
- A review of InnPower's operational performance in the historical period.
- A preview of InnPower's planned expenditures for the forecast period.
- A detailed justification of InnPower's planned capital expenditures in the Test Year.

This DSP covers a planning horizon of five years starting in the 2024 Test Year. Employing this long-term approach requires InnPower to consider future customer needs and any required changes to its distribution system in advance. This approach enhances InnPower's ability to plan ahead and respond to evolving customer needs in a timely manner while managing and levelling the impacts of expenditures on consumer rates to maintain the affordability of its service.

InnPower's DSP has been prepared to support the four key objectives established in the OEB's *Renewed Regulatory Framework (RRF) for electricity*:

1. **Customer Focus:** Services are provided in a manner that responds to identified customer preferences.

2. **Operational Effectiveness:** Continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives.
3. **Public Policy Responsiveness:** Utilities deliver on obligations mandated by the government (i.e.: in legislation and regulatory requirements imposed further to Ministerial directives to the Board).
4. **Financial Performance:** Financial viability is maintained, and savings from operational effectiveness are sustainable.

To realize these four outcomes, InnPower has outlined the following objectives:

- Promoting a safer system for both workers and the public.
- Maintaining security and safety by reducing the vulnerability of the grid to unexpected hazards.
- Ensuring system capacity to facilitate new customer connections.
- Improving cost efficiency through good planning and shared services.
- Improving system reliability by deploying Distribution Automation and improvements to its SCADA technology.
- Executing a prudent, condition-based infrastructure renewal strategy.
- Supporting the deployment of distributed Renewable Energy Generation (REG).

In addition to these objectives, over the next five years InnPower will also adhere to its updated mission, vision, and values, and focus on the eight strategic priorities previously noted in Section 5.2.1.1 above and detailed further in the *InnPower Corporation Strategic Plan for years 2023 to 2027* (attached as Exhibit 1-1-5).

5.2.2 Coordinated Planning with Third Parties

A distributor must demonstrate that it has coordinated infrastructure planning with customers (i.e.: large customers, subdivision developers, and municipalities), the transmitter (i.e.: Regional Infrastructure Planning), other distributors, the Independent Electricity System Operator (IESO) (i.e.: Integrated Regional Resource Planning), or other third parties where appropriate. A distributor should explain whether the consultation(s) affected the distributor's DSP as filed and, if so, a brief explanation as to how.

For consultations that affect the DSP, a distributor should provide an overview of the consultation and relevant material supporting the effects the consultation had on the DSP.

An overview of any consultation(s) should include: The purpose and outcome of the consultation; whether the distributor initiated the consultation or was invited to participate in it; and the other participants in the consultation process (i.e: customers, transmitter, IESO).

A distributor should file the most recent regional plan (Integrated Regional Resource Plan, Regional Infrastructure Plan). In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter. Further, a distributor is required to identify any inconsistencies between its DSP and any current Regional Plan. If there are any inconsistencies, the distributor shall explain the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan.

An increase in communication efforts between municipal planners, consultants, developers, and builders has resulted in a more aligned and organized approach to managing growth. Before preparing this DSP, InnPower consulted with major stakeholders affected by the DSP, with the objective of accurately assessing their needs and confirming the adequacy of the existing capacity of the distribution system; so that the investments could be focused on areas of the greatest need.

InnPower has initiated or participated in consultations with customers, developer groups, regional and municipal governments within InnPower's service territory, HONI, other neighbouring LDCs, the Independent Electricity System Operator (IESO), joint use tenants and telecommunication companies. This DSP considers the outcomes of completed consultations, regional reports and plans, and continued coordination on future ongoing developments with third parties. The following subsections describe each consultation activity InnPower participated in or led that was part of this DSP.

5.2.2.1 Customers Consultations

Purpose of the Consultation

The purpose of InnPower engaging with its customers is to share information with customers, to educate them, and to gather their opinions and insights on its services to ensure that their needs, preferences and expected level of service are taken into consideration during planning activities. InnPower has conducted both formal and informal engagement activities with its customers over the historical period.

Initiation and Participation

InnPower is both proactive and reactive in its customer engagement consultations. Proactive engagements are initiated by InnPower, primarily through its own staff and sometimes through consultants (i.e.: UtilityPULSE) with expertise in polling and gathering public input. Participants normally include a mix of residential, general service, industrial and commercial customers.

Brief Description of Consultation

Customer engagement is often done through our website, social media channels and customer engagement events. InnPower utilizes surveys to educate, inform, and solicit input from customers regarding current and future plans. Customer satisfaction is measured via a recurring two-year cycle of surveys for InnPower customers. Over the historical period, InnPower partnered with UtilityPULSE to conduct two customer satisfaction surveys; the first in 2019 and the second in 2021. Results from these surveys are detailed in InnPower's Scorecards which are available on the OEB website[3].

In addition to these customer satisfaction surveys, InnPower also sends out surveys following the completion of any customer-initiated work to gather feedback from customers on their experience working with InnPower. This feedback enables InnPower to identify any possible areas of improvement and to confirm that customers continue to receive high-quality service from InnPower.

InnPower also conducted a survey on customer priorities in 2022 to allow InnPower to establish what is most important to customers. InnPower ran the Customer Priority Survey on two separate occasions. The survey first ran from August 17, 2022 to September 26, 2022 (40 days in total) and was re-opened again in October for one week (October 18–25, 2022) in an attempt to gather feedback from general service industrial and commercial customers. InnPower invited its customers to

[3] Ontario Energy Board. Electricity Utility Scorecards

participate in the online survey by sending out emails and promoted the survey through several different platforms, including:

- The news page, homepage scrolling and pop-up banners on its website.
- Mentioning the survey in customer bills under the *"Important Information/Messaging"* section.
- Social campaigning across its social platforms including Facebook, Twitter, and Instagram.
- Offering the survey in-person at the *MakerFest 2022* community event held on September 24th, 2022.

InnPower successfully gathered 150 total responses, of which 91.3% were from residential customers, 4.0% from general service customers, and 4.7% from commercial and industrial customers. Out of the various priority options provided, the top five priorities selected by the customers included:

1. Affordable cost of electricity (as selected by 92.67% of the respondents).
2. Maintaining and upgrading equipment to ensure a safe and reliable electricity supply (as selected by 80.00% of the respondents).
3. Investing in storm hardening (physical improvements that can make utility infrastructure more resistant to weather (as selected by 57.33% of the respondents).
4. Improving electricity outage response time (as selected by 56.00% of the respondents).
5. Two options tied for 5th:
   - Better communication from InnPower when electricity outages occur (as selected by 40% of the respondents).
   - Investing in systems to accommodate new technologies (REG, electric vehicles, charging stations, etc.) (as selected by 40% of the respondents).

Consultation Materials

As noted above, InnPower partnered with UtilityPULSE to conduct two customer satisfaction surveys over the historical period; the first in 2019 and the second in 2021. Results from these surveys are included in InnPower's scorecards, which are available on the OEB website[4]. InnPower's Customer Priority Survey results are included in Appendix B.

Consultation Outcomes and Impact on this DSP

Customer feedback has been integrated into the preparation of this DSP. To ensure a safe and reliable electricity supply, InnPower has several annual System Renewal programs budgeted each year to address the need to replace deteriorated assets at the end of their service life, including pole replacements, transformer replacements, recloser replacements, switch replacements and switchgear replacements. These investments play a crucial role in the overall reliability, safety, and sustainment of the distribution system.

The recent migration to a comprehensive geographic information system called Utility Network Model (GIS-UNM) and ongoing upgrades to its OMS will allow InnPower to make faster decisions to troubleshoot and improve its system reliability and continue to make prudent decisions into asset

[4] Ontario Energy Board. Electricity Utility Scorecards

maintenance and replacement to keep costs down for customers. InnPower also plans to automate more of its network over the forecast period to reduce the size and duration of outages. Specifically, InnPower plans to replace more manual switches with automated switches in the field and, with its improved predictive analysis, utilize a concept called *Fault Location, Isolation, and Service Restoration* (FLISR) to have the system automatically generate a list of switching orders and automatically execute them. This is the fundamental concept of a self-healing network.

InnPower has also taken steps to establish a Utilities Climate Change Working Group (UCCWG) in collaboration with the Town to discuss and recommend practical solutions to adaptation and mitigation of climate change on utility critical infrastructure.

COVID-19 has had a significant impact on InnPower customer relations and engagement efforts which solidified the need to transition to and implement a stronger digital strategy while enhancing InnPower's visibility and reach in the community and improving the overall customer experience. InnPower aims to implement the following initiatives/actions with respect to enhancing its overall digital strategy:

- **Online Forms:** InnPower offers digital friendly forms to customers in the form of fillable PDF and online forms and smart forms that integrate to our Customer Information System (CIS) through our customer portal. We aim to improve the customer experience and reduce the required number of touchpoints that InnPower's customer service team needs to make with customers.
- **Online Live Chat Website:** With the goal of improving accessibility to customers, providing another way to communicate with customer service and enhancing the digital strategy, InnPower will introduce a live chat feature for customers to its website in 2023 for outage communications. This will also include a text message feature to report and provide updates on outage status.
- **Communication during Outages:** InnPower is currently evaluating text communications strategies for outages through a third-party solution as well as opportunities from InnPower's existing OMS. InnPower is also working on a major overhaul of its outage notification and communication strategy.
- **New Online Customer Portal:** InnPower will further enhance its online customer portal to facilitate easier move order submissions, online payment arrangements, seamless online credit card payment options and green button capabilities as regulated by the Ministry of Energy (MOE).
- **Video and Animation Education and Marketing:** Over the next five years, InnPower's engagement team will be investigating and exploring various video production and animation solutions and partnerships with other utilities to aid in improving its public education visually.

InnPower's Green Button solution, which will be made available by November 1st, 2023, will also enhance customer choice in Ontario to help customers:

- Better understand energy use.
- Manage energy use in a way that works best for homes or businesses.
- Lower energy bills and reduce energy costs.
- Find new ways to invest in energy efficiency upgrades at homes or businesses.
- Be empowered with energy usage information to reduce and shift energy use.

During 2023, InnPower plans to continue working collaboratively with CHEC to implement the required Green Button solution through the entire process of vendor selection, testing, and implementation.

Through its energy services partnership with InnTerprises, InnPower plans over the next couple of years to explore ways of using this data to help customers reduce their carbon footprint through in-home technologies.

With respect to customer satisfaction, InnPower remains committed to focusing on affordability, reliability, and sustainability in all major organizational decisions. In relation to this, InnPower plans to increase its social media and conventional communication through a media and public relations strategy, provide increased education on the electricity industry, electrical safety and outages to the community and public consultation and engagement to develop mutually beneficial alternatives that have stakeholder input. InnPower will continue is work on preventative maintenance including equipment inspections, vegetation management, and animal mitigation management. Further, InnPower plans to conduct ad-hoc surveys of customers after they have received service from InnPower to identify what went well and what we can improve on.

5.2.2.2 Subdivision Developers

Purpose of the Consultation

The main goal of consultations with developer groups is to share information and coordinate long-term planning such that the needs of all parties can be considered when planning for resources.

Initiation and Participation

InnPower's System Planning and Operations departments initiate meetings with larger developer groups, such as the Salem Developers Group and the Hewitt Developers Group, on a monthly basis. In addition to InnPower and the developer groups, other potentially impacted stakeholders such as the Town of Innisfil, the City of Barrie, the County of Simcoe, Enbridge, InnServices, and the IESO may be involved in these meetings as well. Invitations to participate are determined on a case-by-case basis depending on the scope of the discussions and potential impacts.

Brief Description of Consultation

Meetings with larger developers are based on mutual needs of the developers' requirement for services and InnPower's ability to deliver the required power. These meetings also provide an excellent opportunity for open dialogue with other stakeholders to learn about and discuss their current and upcoming plans.

Participating in these consultations allows InnPower to learn about and share information about upcoming projects in the community and enhances the planning process by being able to size its infrastructure appropriately to support the projects. Although detailed information about upcoming projects are not typically available five years in advance, these consultations do provide an estimate of the volume of anticipated projects involving new customer connections, subdivision developments, and expansions.

Consultation Materials

The outcomes of these consultations are in the form of development information such as plans and associated schedules and budgets.

Consultation Impact on this DSP

The information obtained from developer groups have been used as an input to identify investment level requirements under the System Access investment category proposed in this DSP (i.e.: subdivisions, expansion developments, and new services). Currently, developers in South Barrie

alone indicate that an estimated 12,685 new connections (residential, institutional, commercial, and industrial) are expected to be in service by 2028 and 13,315 post 2028. A few of the larger subdivision initiatives happening in InnPower's service area over the forecast period include, but are not limited to:

- **Sleeping Lion**: A subdivision development with an anticipated build-out of 5,000 homes on the 6th Line in Innisfil.
- **Friday Harbour:** A resort community within the area of Big Bay Point is a 600-acre site with a total build-out of 3,000 units over a ten-year period.
- **Hewitt Creek**: A subdivision development with an anticipated build-out of 900 homes on Mapleview Drive.
- **Barrie Lockhart Rd Gp—Sorbara**: A subdivision development with an anticipated build-out of 485 homes on Lockhart east of Huronia.
- **Bistro 6**: A subdivision development with an anticipated build-out of 788 homes on Mapleview drive east of Yonge.
- **Blue Sky/Honey Field Lands**: A subdivision development with an anticipated build-out of 890 homes on Big Bay Point Road and Mapleview Drive East.

5.2.2.3 Municipalities and Other Government Entities

Purpose of the Consultation

InnPower regularly interacts with the Town of Innisfil, the City of Barrie, the County of Simcoe, and the Ministry of Transportation (MTO) to coordinate infrastructure planning within its service territory so that new connections to customers can be connected in a timely manner and projects involving line relocates to facilitate road reconstruction projects can be planned.

Initiation and Participation

Participants in these engagements include InnPower, the Town of Innisfil, the City of Barrie, the County of Simcoe, and the MTO. InnPower meets with the Town of Innisfil and the City of Barrie monthly, and meetings with the County of Simcoe tend to occur on a quarterly basis unless there is a specific project underway that requires more frequent coordination. The frequency of meetings with the MTO are also dependent on ongoing project work. For each project identified, InnPower typically participates in exploratory meetings, progress meetings and closing meetings.

Brief Description of Consultation

Coordination with the Town of Innisfil, the City of Barrie, the County of Simcoe, and the MTO requires advanced planning to ensure timing and funding is available to collaborate with these entities for improvements.

The Town of Innisfil submits a Transportation Master Plan, which outlines high-level objectives for road works over a ten-year period. Similarly, the County of Simcoe submits a plan outlining high-level objectives over a five-year period. These plans help inform InnPower's planning and coordination with these entities. InnPower also attends project progress meetings to minimize conflicts and reduce re-designs for either party while ensuring that cost and reliability remain the prime focus.

Consultation Materials

The outcomes of these consultations are in the form of development information such as plans and associated schedules and budgets.

Consultation Impact on this DSP

The information obtained from these consultations has been used as an input to identify investment level requirements under the System Access investment category proposed in this DSP (i.e.: new services, road authority works, and expansion developments). A few of the larger road authority works and municipality developments happening in InnPower's service area include, but are not limited to:

- **Innisfil Beach Road, 10th Sideroad to Yonge St.:** This relocation project, corresponding to Phase 2 of the overall project, will accommodate the widening of Innisfil Beach Road from two lanes to five lanes due to increased traffic demand. Ongoing coordination for this project is not only with the County of Simcoe, but also Bell, Rogers, Enbridge and InnServices to ensure all utilities are accommodated and transferred to align with project timelines.
- **Yonge St and 9th Line: Roundabout installation:** This project involves the relocation of InnPower assets to accommodate the replacement of an intersection with a roundabout.
- **Hewitt and Salem Projects:** Due to the large number of customers that will eventually reside in these areas, plans and coordination efforts have already begun to ensure that the new pole lines being built by InnPower to accommodate the growth also align with future road widenings to limit the amount of any potential relocations in the future.

Two other projects potentially planned in 2023 include asset relocations to accommodate a Town of Innisfil roundabout installation at 25th Sideroad and 13th Line, as well as a County of Simcoe Road widening project at Killarney Beach Road and Yonge St. Since the County of Simcoe project is through a historical area, undergrounding is part of the planned replacement due to the removal of any public space for poles.

5.2.2.4 Regional Planning Process

The Regional Planning Process represents a coordinated, transparent, and cost-effective planning of electrical infrastructure at the regional level, which was mandated by the OEB in 2013. To facilitate effective planning, the Province of Ontario is divided into 21 planning regions. As the lead transmitter, HONI conducts a Need Assessment (NA) and develops a Regional Infrastructure Plan (RIP) that involves representatives from the IESO, and LDCs of the planning region.

InnPower is part of the South Georgian Bay/Muskoka planning region, shown in Figure 5.2-3. The planning region includes the following participants involved in the scoping assessment and regional planning for the South Georgian Bay/Muskoka region:

- IESO
- HONI Transmission
- HONI Distribution
- Alectra Utilities
- InnPower
- Orangeville Hydro

- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Inc.
- Newmarket-Tay Power Ltd.
- Wasaga Distribution Inc.

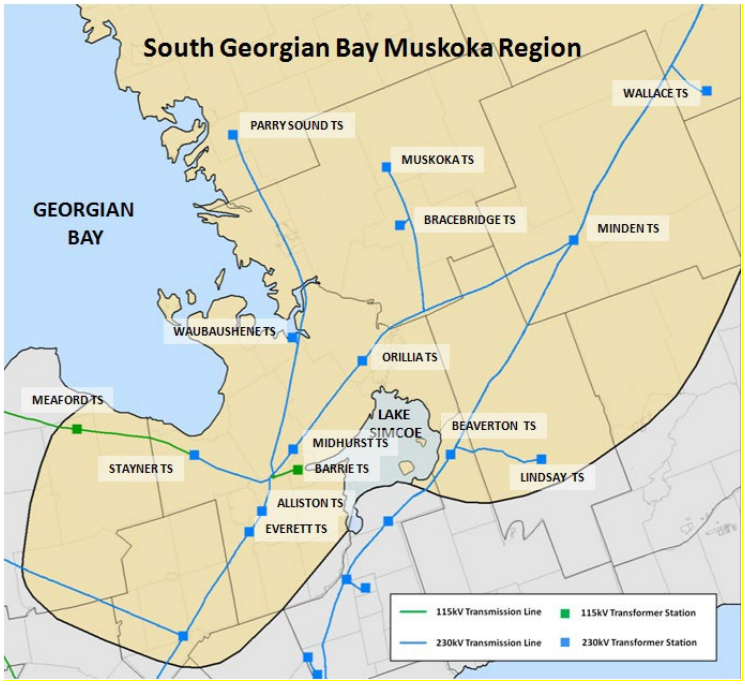


Figure 5.2-3: South Georgian Bay/Muskoka region

The South Georgian Bay/Muskoka planning region is further divided into two sub-regions—Barrie/Innisfil Sub-region and the Parry-Sound/Muskoka Sub-region (depicted in Figure 5.2-4). InnPower is embedded within the Barrie/Innisfil Sub-region.

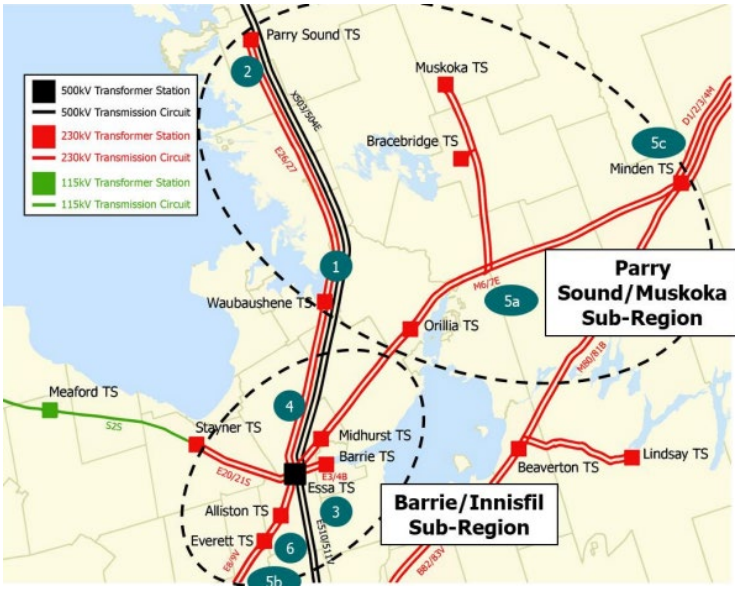


Figure 5.2-4: Barrie/Innisfil sub-region

The first regional planning cycle for the region was completed in August 2017 with the publishing of the RIP. The plan identified needs and recommendations for the near- and medium-term timeframes. A key outcome of this planning process was the BATU project to rebuild and uprate the Barrie TS to a 230 kV supply to meet the capacity and end-of-life needs identified in South Barrie and Innisfil regions. The BATU project is currently underway with a planned in-service date scheduled for December 2023.

The second cycle of regional planning started in January 2020 with a Needs Assessment (NA), which is in accordance with the Regional Planning process—that is the regional planning cycle should be revisited at least every five years. The South Georgian Bay/Muskoka NA report was published by HONI in April 2020, which recommended that several initiatives required regional coordination. The outcomes of the NA were put into the Scoping Assessment to determine the nature of the planning process. The Scoping Assessment was released by the IESO in November 2020, which identified the need for further coordination at the sub-regional level to develop an Integrated Regional Resource Plan (IRRP) for each of the two sub-regions. The IRRP for the Barrie/Innisfil sub-region was released in May 2022. All the proposed investments as part of the 2024-2028 DSP align with the IRRP.

5.2.2.4.1 Needs Assessment

An NA was carried out by HONI for the South Georgian Bay/Muskoka region from January to April 2020. The purpose of the NA was to identify any new needs for the region as well as recommend a path forward for each need by either developing a preferred plan or identifying which needs require further assessment and/or regional coordination. Inputs considered for the NA included:

- Load forecast for all supply stations.
- Known capacity and reliability needs, operating issues and/or major assets approaching the End-of-Life (EOL).
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the region.

The report identified several needs in the region that may require further regional coordination and concluded that these needs should be reviewed further under the IESO-led Scoping Assessment process. A key need identified that directly impacted InnPower was the need to develop supply capacity solution(s) for Innisfil area load growth.

Purpose: To identify any new needs and/or to reconfirm needs identified in the previous planning cycle that require regional coordination.

Participants: HONI, IESO, Alectra Utilities, Lakeland Power, Elexicon Energy, Orillia Power, EPCOR, InnPower, Orangeville Hydro, Newmarket Hydro, and Wasaga Distribution.

Status: Complete.

Deliverables: NA Report issued by HONI on April 30, 2020 (see Appendix C)

5.2.2.4.2 Scoping Assessment

A Scoping Assessment Outcome Report was developed for the South Georgian Bay/Muskoka region in November 2020. The main outcome of the Scoping Assessment is the identification of the best planning approach for each need identified in the NA. The Scoping Assessment concluded that individual IRRPs are necessary for both the Barrie/Innisfil and Parry Sound/Muskoka sub-regions. Key needs relating to InnPower's service area identified to go through the IRRP process are as follows:

- InnPower identified supply capacity constraints on the 44 kV feeder level starting in 2025.
- Up-sized Barrie TS will have a station capacity need arising in 2029.

Purpose: To further review the needs identified, in combination with information collected as part of the NA and information on potential wires and non-wires alternatives, in order to assess and determine the best planning approach for the whole or parts of the region.

Participants: IESO in collaboration with the South Georgian Bay/Muskoka regional participants.

Status: Complete.

Deliverables: Scoping Assessment Outcome Report issued by IESO on November 30, 2020 (see Appendix D)

5.2.2.4.3 Innisfil Area Supply Alternatives

An Innisfil Area Supply Alternatives Report (see Appendix E) was prepared by HONI in July 2021, with support from Alectra Utilities and InnPower, to complement the Scoping Assessment completed as part of the then ongoing IESO IRRP development process. The Innisfil Area Supply Alternatives Report presented and compared four alternatives to address the future Innisfil area supply needs to be identified. Specifically, the 44 kV 2-feeder supply from Barrie TS will only provide a 50 MW supply limit and the demand in the area is forecast to reach 93 MW by 2029. The preferred alternative was presented in this report as:

- Provide a 230 kV tap connection to Innisfil service territory for a new TS. This will increase supply capacity for InnPower through the construction of a new 230/27.6 kV 83MVA TS and connection to the new 230 kV transmission lines (E28B/E29B) that will be available upon the completion of the BATU project.

The Innisfil Area Supply Alternatives Report recommended that HONI and InnPower proceed with development work for the preferred option in 2021 in order to meet an in-service date of 2025 (note:

the projected in-service date has changed since the issuance of this report and is now estimated to be in the 2027/28 timeframe).

InnPower has started doing some pre-work for the new TS Project in 2021, consisting of planning, designing, and conducting an EA. InnPower is also actively working with the IESO, HONI and Alectra to further assess, refine, and finalize the proposed solution. Engagements have commenced and will continue throughout the development of this project.

Purpose: To explore supply alternatives to address increased load growth in the Innisfil area and advance the ideas and recommendations from the 2020 Needs Assessment Report.

Participants: HONI, IESO, InnPower, and Alectra.

Status: Completed

Deliverables: Regional Infrastructure Planning South Georgian Bay—Muskoka: Innisfil Area Supply Alternatives report issued by HONI on July 5, 2021 (Appendix E).

5.2.2.4.4 Barrie/Innisfil Integrated Regional Resource Plan

Working Groups were established to undertake IRRPs for each sub-region to address the needs in these areas. The technical working group for the Barrie/Innisfil sub-region comprised of the IESO, Hydro One distribution and transmission, Alectra Utilities and InnPower. Since InnPower is part of the Barrie/Innisfil sub-region, the following information is focused on the IRRP developed for this region.

With the demand growth expected to increase in the Innisfil area with InnPower's demand forecasted to reach 113 MW by 2029, the overall demand forecast for Barrie TS will reach its summer 10-day Limited Time Rating (LTR) by 2027, and a supply constraint on the Barrie TS at the 44 kV distribution level is also expected starting in 2025. The IRRP recommends constructing a new 230/27.6 kV transformer substation with a 230 kV tap connection to the upgraded 230 kV circuits E28B/E29B that will be in place once the BATU reinforcements are in-service. In response to this recommendation, InnPower is actively coordinating with Hydro One and progressing the development of the new TS Project. The other near/medium term actions identified in the IRRP, including the CT ratio adjustment at the Everett TS and the like for like replacement of the E8V/E9V circuits, do not directly involve InnPower and as a result, there is no impact on the capital investments proposed in this DSP.

In addition to the near/medium term actions noted above, the IRRP recommended a few non-wire alternative options to meet the longer-term needs. InnPower, along with Alectra Utilities, Hydro One Transmission and Distribution, and the IESO will continue to:

- Monitor demand growth in the area and revisit these needs during the next cycle of regional planning.
- Monitor uptake of the Conservation Demand Management (CDM) framework as well as energy efficiency initiatives in the Community Energy Plans (CEPs) and assess the impact of these additional savings on the timing of local reliability needs.
- Monitor electrification trends and their impact on the demand forecast.

Purpose: To provide recommendations to address the electricity needs of the sub-region over the next 20 years.

Participants: IESO, Hydro One Distribution and Transmission, Alectra Utilities and InnPower.

Status: Complete.

Deliverables: Integrated Regional Resource Plan – Barrie/Innisfil (Appendix F).

5.2.2.4.5 Regional Infrastructure Plan

The RIP issued by Hydro One Transmission in December 2022 represents the final phase of the second cycle of the South Georgian Bay-Muskoka Regional Planning process. The RIP provides a consolidated summary of needs and recommended plans for the region over a ten-year planning horizon (2022-2032) based on available information. Out of the list of major infrastructure investments planned over this horizon, InnPower is leading the construction of the new 230/27.6kV 2x83MVA DESN TS (i.e.: the new TS Project).

In accordance with the RIP, InnPower in coordination with Hydro One Transmission, will continue progressing the implementation of this project and keep the South Georgian Bay-Muskoka Regional Technical Working Group appraised of the project status.

Purpose: To develop an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information.

Participants: IESO, Hydro One Transmission and Distribution, Alectra Utilities, InnPower, Orangeville Hydro, Elexicon Energy, Lakeland Power, EPCOR Electricity Distribution Ontario Inc., Newmarket-Tay Power Distribution Ltd. and Wasaga Distribution Inc.

Status: Complete.

Deliverables: South Georgian Bay-Muskoka Regional Infrastructure Plan (Appendix G).

Regional Planning Process Impact on this DSP

Explain how consultation(s) affected the distributor's DSP as filed.

The regional planning process has identified an increased supply capacity need in the Innisfil area by 2025.The preferred solution identified to address this need is to provide a 230 kV tap connection to Innisfil service territory for a new TS to increase supply capacity for InnPower through the construction of a new 230/27.6kV 2x83MVA DESN TS and connection to the new 230 kV transmission lines (E28B/E29B) that will be available upon the completion of the BATU project in December 2023. This solution provides a robust transmission solution to meet InnPower's demand forecast and will also allow for future load growth beyond the study period. This solution will also help to relieve Barrie TS which will see a capacity need in 2029.

Continued development and construction of the new TS Project and 230 kV line is expected to continue over the forecast period but given that the project in service date is expected to occur near the end of the forecast period (or potentially beyond), the costs associated with this project will remain in WIP and be addressed in InnPower's next rebasing application.

5.2.2.5 Telecommunication Entities

On January 11, 2022, the OEB issued further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include the following information in its capital plan:

- *The number of consultations that were conducted and a summary of the manner in which the distributor determined with whom to consult.*
- *A summary of the results of the consultations.*

- *A statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how.*

Consultations

InnPower has an established Joint Use program within its service territory that allows for other pole attachments such as cable, telephone, fibre, etc. The joint use agreements set out the required design standards to ensure the safety of employees and the public.

In addition to this, InnPower informs service providers of its upcoming plans to identify and promote any opportunities for coordination between parties. InnPower organizes regular status meetings with the telecommunications companies to review project status, make-ready work, future work and align project timelines to ensure efficient project completion and reduced customer complaints for each party. Table 5.2-4 summarizes the formal consultations with communication companies that InnPower has organized and been involved in since the last DSP filing.

Table 5.2-4: Summary of Consultations

Telecommunication Company	Consultation Frequency	Participants
Rogers	Bi-weekly	Rogers Utility Specialist, Rogers Design Tech, InnPower Design Tech, InnPower Engineering Supervisor
Bell	On a per project basis; bi-weekly during projects	Bell Utility Specialist, Bell Design Tech, InnPower Design Tech, InnPower Engineering Supervisor
Zayo	On a per project basis; bi-weekly during projects	Zayo Utility Specialist, Zayo Design Tech, InnPower Design Tech, InnPower Engineering Supervisor

Result of Consultations

Results of these consultations includes:

- Aligned project timelines and priorities for all entities.
- Communication of project status updates.
- Communication of project delays and reason(s) for the delays (i.e.: supply chain.)
- Coordination of upcoming works.
- Comments on design reviews.
- Make-ready approvals.
- Coordination for telecommunication transfers.

Ongoing consultation and coordination ultimately help ensure that make-ready work is completed in a timely manner and that telecommunication entities are aware when it is complete.

Consultation Effects on the DSP

Any project costs resulting from ongoing consultations with telecommunication companies are captured under InnPower's IPCSA01 New Services program, which includes layouts and customer-driven work which is fully recoverable. Historical costs have been used to project spending over the forecast period.

The impacts of the Accelerated High-Speed Internet Program (AHSIP) to support Ontario's new Broadband and Infrastructure Expansion Act, 2021 have not been added to this DSP as the communications partner selected for the area (i.e.: Rogers) is still assessing the project and how to accomplish this task.

5.2.2.6 Renewable Energy Generation

A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are REG investments in the region. If there are REG investments proposed in the DSP, a distributor is expected to demonstrate that it has coordinated with the IESO, other distributors, and/or transmitters, as applicable, and that the investments proposed are consistent with a Regional Infrastructure Plan. This coordination is demonstrated by a comment letter provided by the IESO, to be filed with the DSP.

A REG Investment Plan outlining the plan to support connection of renewables over the forecast period was prepared by InnPower and submitted to IESO on March 7, 2023. The plan indicates that InnPower is not proposing any capital investments to increase the capacity of its distribution system to enable further REG connectivity from 2023 to 2028. The IESO provided a response letter on March 14, 2023, upon completion of its review. The plan and response letter are attached in Appendix H and Appendix I, respectively.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

Distributors are expected to summarize objectives for continuous improvement (i.e.: reliability improvement and other desired outcomes) the distributor set out to address in its last DSP, and to discuss whether these objectives have been achieved. For objectives not achieved, a distributor should explain how it affects this DSP and, if applicable, improvements a distributor has implemented to achieve the objectives set out in Section 5.2.1.

In order to continually improve its operating performance, InnPower continually measures and monitors its performance. The performance measures tracked by InnPower align with the OEB's "Scorecard—Performance Measures" for electricity distributors, as listed below:

- Service quality
- Customer satisfaction
- Safety
- System reliability
- Asset management
- Cost control

- Connection of renewable generation
- Financial ratios.

Where applicable, the performance measures included on the scorecard have an established minimum level of performance to be achieved. The scorecard is designed to track and show InnPower's performance results over time and helps to benchmark its performance and improvement against other utilities and best practices. Table 5.2-5 summarizes InnPower's performance during historical years from 2017 to 2022. Explanations for any missed targets, including the impact on the DSP and any associated improvements, are detailed in the following sub-sections.

Table 5.2-5: DSP Performance Measures

Performance Outcome	Measure	Metric	2017	2018	2019	2020	2021	2022	Target [1]
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	93.28%	91.84%	99.56%	100.00%	99.50%	95.83%	> 90%
		Scheduled Appointments Met on Time	93.50%	87.21%	98.40%	99.51%	100.00%	100.00%	> 90%
		Telephone Calls Answered on Time	80.23%	83.85%	90.40%	92.53%	90.18%	82.96%	> 65%
	Customer Satisfaction	First Contact Resolution	99.40%	99.79%	99.93%	99.95%	99.95%	99.89%	-
		Billing Accuracy	99.79%	99.73%	99.88%	99.90%	99.83%	99.87%	98%
		Customer Satisfaction Survey	B	B	A	A	B+	B+	-
Operational Effectiveness	Safety	Level of Public Awareness	85.00	85.00	84.00	84.00	83.00	83.00	-
		Level of Compliance with Ontario Regulation 22/04 [2]	C	C	C	C	C	C	C
		Number of General Public Incidents [2]	0	0	0	0	0	0	0
		Rate per 10, 100, 1000 km of line [2]	0	0	0	0	0	0	0
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	1.54	2.66	1.52	1.81	1.78	1.04	2.15
		Ave. Number of Times that Power to a Customer is Interrupted	1.05	0.88	0.61	1.10	0.70	0.87	1.37
	Asset Management	Distribution System Plan Implementation Progress	In progress	98%	110%	93%	109%	62% [3]	-
	Cost Control	Efficiency Assessment	3	3	3	3	3	3	Maintain Group 3 or improve
		Total Cost per Customer [2]	$857	$834	$847	$852	$897	$839	
		Total Cost per km of Line [2]	$17,136	$17,231	$10,844	$11,219	$12,072	$11,504	
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation Connection Impact Assessment (CIA) Completed on Time	-	-	-	100%	-	-	-
		New Micro-embedded Generation Facilities Connected on Time	100%	100%	-	-	-	-	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	0.88	0.94	1.06	0.84	0.48	1.08	-
		Leverage: Total Debt (short-term and long-term) to Equity Ratio	1.78	1.61	1.60	1.42	1.27	1.07	-
		Regulatory Return on Equity (ROE) – Deemed (included in rates)	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	-
		Regulatory ROE – Achieved [2]	0.94%	11.47%	10.09%	9.69%	9.26%	12.79%	-

[1] Targets shown are for year 2021.

[2] 2022 value not available at the time of CoS Application submission. The finalized OEB Scorecard will be available in 2023 Summer. These values have been indicated as "TBD".

[3] The measure is net capitalized versus budgeted investment (excluding WIP). The lower result is due to the delays of a few Road Relocation projects (about $1.4M) as well as expansion projects totally driven by the third parties and are beyond InnPower's control. Overall, InnPower executed $13.5M dollars of Capital Projects.

A review of InnPower's historical performance above indicates that InnPower has largely met or exceeded expectations over the historical period, with the following exception:

- **SAIDI in 2018**: In 2018, the System Average Interruption Duration Index (SAIDI) target was missed due to faulty equipment and tree encroachments into Overhead (OH) distribution lines. InnPower has taken steps to readily identify, troubleshoot, and sectionalize problem areas in order to minimize outages going forward including the implementation of a new Vegetation Management program in late 2020. InnPower continues to make investments in system reliability through smart devices such as fault indicators, switches, control systems, and outage response software, which will continue to help improve overall system reliability over the long term.

5.2.3.2 Service Quality and Reliability

Chapter 7 of the OEB's Distribution System Code outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. A distributor is required to provide the reported SQRs for the last five historical years. A distributor should also provide explanations for material changes in service quality and reliability, and whether and how the DSP addresses these issues. The OEB expects any five-year declining trends in reliability for SAIDI and SAIFI to be explained. If a distributor has reliability targets established in a previously filed DSP, as described below, any underperformance should also be explained.

A completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, must be filed. A distributor must confirm that data is consistent with the scorecard or must explain any inconsistencies.

A summary of performance for the historical period using the methods and measures (metrics/targets) identified and described above, and how this performance has trended over the period, should be included. This summary must include historical period data on:

- *All interruptions.*
- *All interruptions excluding loss of supply.*
- *All interruptions excluding Major Events and loss of supply for the following:*
  - *The distribution system average interruption frequency index (SAIFI).*
- *System average interruption duration index (SAIDI).*

InnPower's service quality and reliability performance are detailed further in the following subsections. Service quality and reliability indicators can also be found in Exhibit 2 Appendix 2-G of this CoS Application.

5.2.3.2.1 Service Quality Requirements

InnPower sets a high standard for performance when it comes to customer care. InnPower strives to deliver customer excellence and value through the execution of its investments and operations. InnPower tracks and reports the Service Quality Requirements (SQR) outlined in Chapter 7 of the OEB's Distribution System Code (DSC). InnPower's SQR performance for the historical period is summarized in Table 5.2-6. Explanations for any material changes, missed targets or declining trends, and whether and how the DSP addresses these issues, is detailed below.

Table 5.2-6 Historical Service Quality Metrics

Service Quality Metric	2017	2018	2019	2020	2021	2022	Minimum Standards
Low Voltage Connections	93.28%	91.84%	99.56%	100.00%	99.50%	95.83%	> 90%
High Voltage Connections	-	-	-	-	-	-	> 90%
Telephone accessibility	80.26%	83.85%	90.40%	92.53%	90.18%	82.96%	> 65%
Appointments met	93.50%	87.21%	98.40%	99.51%	100.00%	100.00%	> 90%
Written response to enquiries	99.46%	99.69%	99.90%	99.46%	99.86%	99.56%	> 80%
Emergency Urban Response	-	-	-	-	-	-	> 80%
Emergency Rural Response	95.65%	95.74%	97.92%	100.00%	100.00%	98.04%	> 80%
Telephone call abandon rate	5.55%	3.98%	2.21%	2.51%	1.89%	1.55%	< 10%
Appointment scheduling	97.83%	95.25%	95.88%	99.96%	99.91%	100.00%	> 90%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	> 100%
Reconnection Performance Standard	98.47%	98.90%	100.00%	100.00%	100.00%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	100.00%	100.00%	-	-	-	-	> 90%
Billing Accuracy	99.79%	99.73%	99.88%	99.90%	99.83%	99.87%	> 98%

A review of the service quality indicators data above indicates that InnPower has exceeded the SQR expectations over the historical period, with the exception of the appointments met in 2018. The Appointments Met target was missed in 2018 as a result of changes in management, as well as a shortage of staff to meet these appointments following increased trouble calls, storms, and restoration time.

5.2.3.2.2 Reliability Requirements

The key metrics that InnPower tracks to measure reliability are the SAIDI, System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). SAIDI, SAIFI and CAIDI are measured under three scenarios:

1. By including all power interruptions.
2. By excluding interruptions due to Loss of Supply (LOS).
3. By excluding interruptions due to LOS and Major Event Days (MED).

In addition, the root cause of power interruptions is monitored and analyzed. Each power outage that occurs on InnPower's distribution system is recorded and an outage cause code is assigned. The number of customer interruption hours for each cause code provides a picture of the root cause of power interruptions. There are no targets for root cause of power interruptions, but it is monitored for investment planning purposes. InnPower's reliability metric values for the historical period are shown in the tables and figures below.

Table 5.2-7: Historical Reliability Performance Metrics: All Cause Codes

Metric	2017	2018	2019	2020	2021	2022	Average
SAIDI	1.54	5.16	1.57	5.45	3.73	2.52	3.32
SAIFI	1.05	1.34	0.63	2.23	1.37	1.58	1.37
CAIDI	1.47	3.85	2.49	2.44	2.72	1.59	2.42

Table 5.2-8: Historical Reliability Performance Metrics: LOS and MED Adjusted

Metric	2017	2018	2019	2020	2021	2022	Average
Loss of Supply Adjusted							
SAIDI	1.54	4.78	1.52	5.07	3.73	2.52	3.19
SAIFI	1.05	1.26	0.61	2.05	1.37	1.58	1.32
CAIDI	1.47	3.79	2.49	2.47	2.72	1.59	2.42
Loss of Supply and Major Event Days Adjusted							
SAIDI	1.54	2.66	1.52	1.81	1.78	1.04	1.73
SAIFI	1.05	0.88	0.61	1.10	0.70	0.87	0.87
CAIDI	1.47	3.02	2.49	1.65	2.54	1.20	2.06

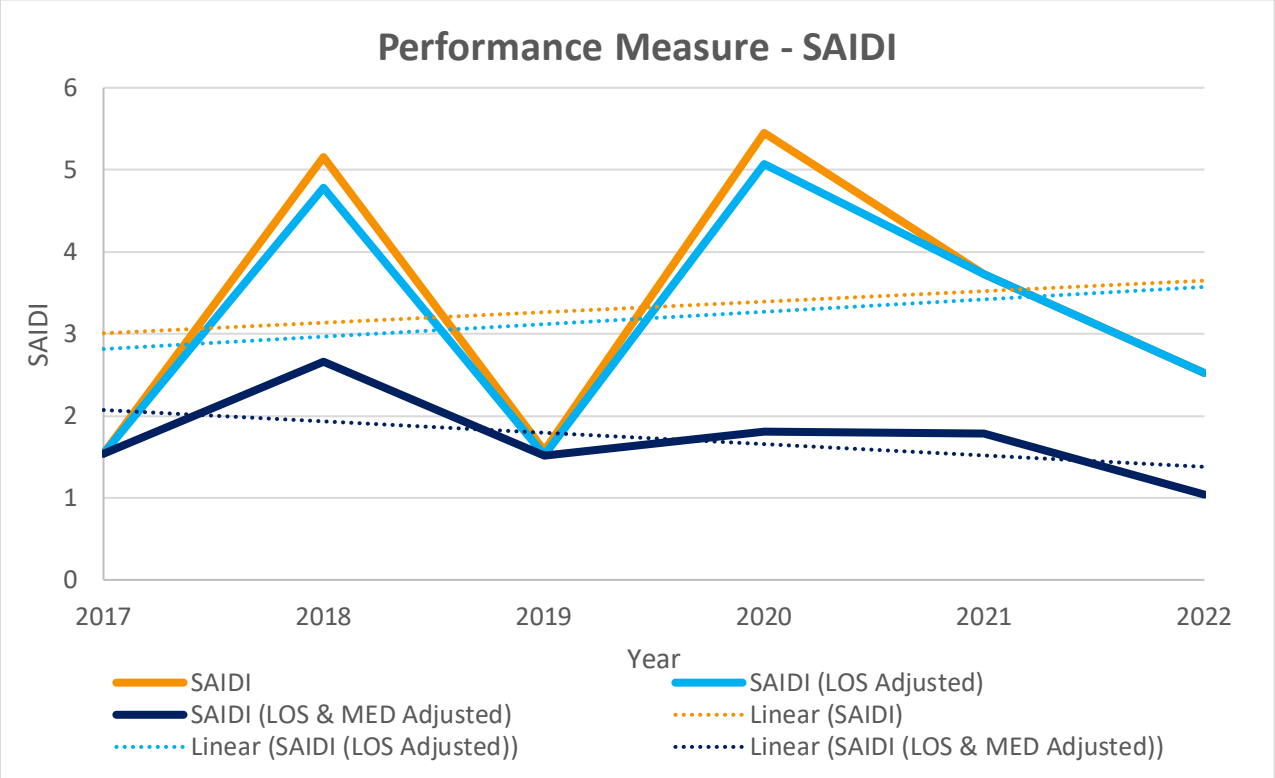


Figure 5.2-5: Performance Measure: SAIDI

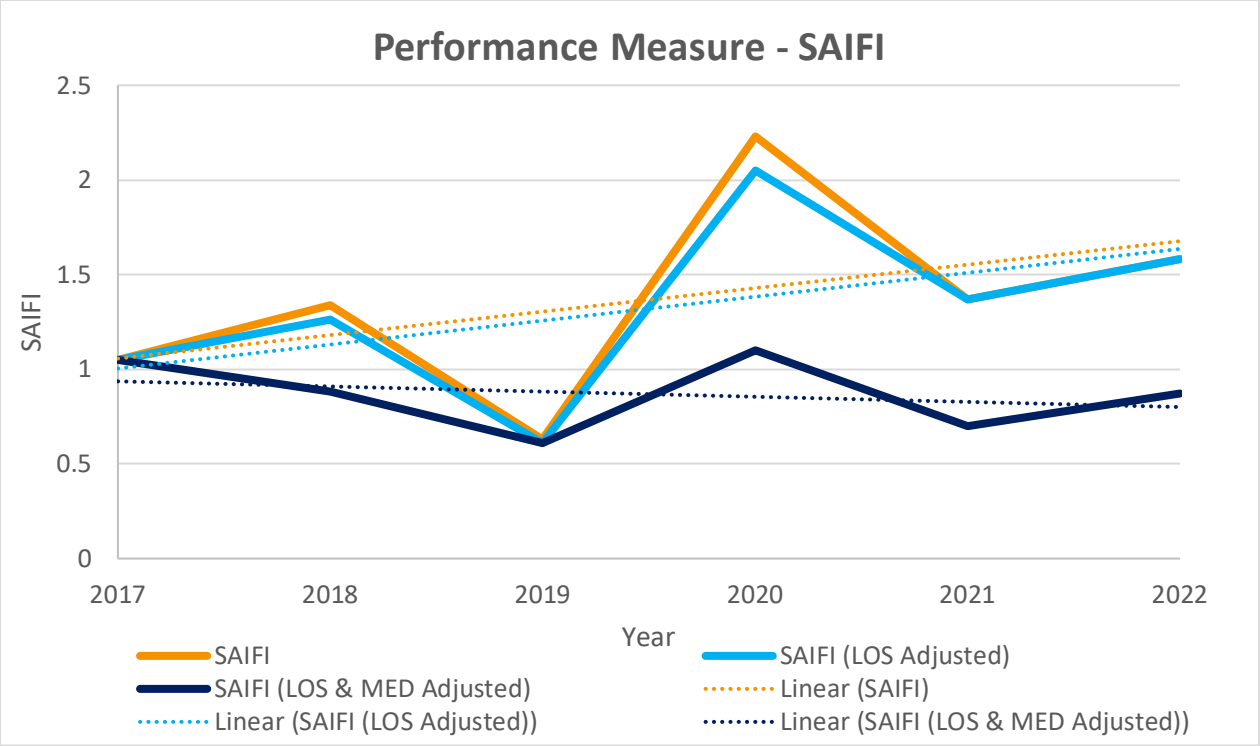


Figure 5.2-6: Performance Measure: SAIFI

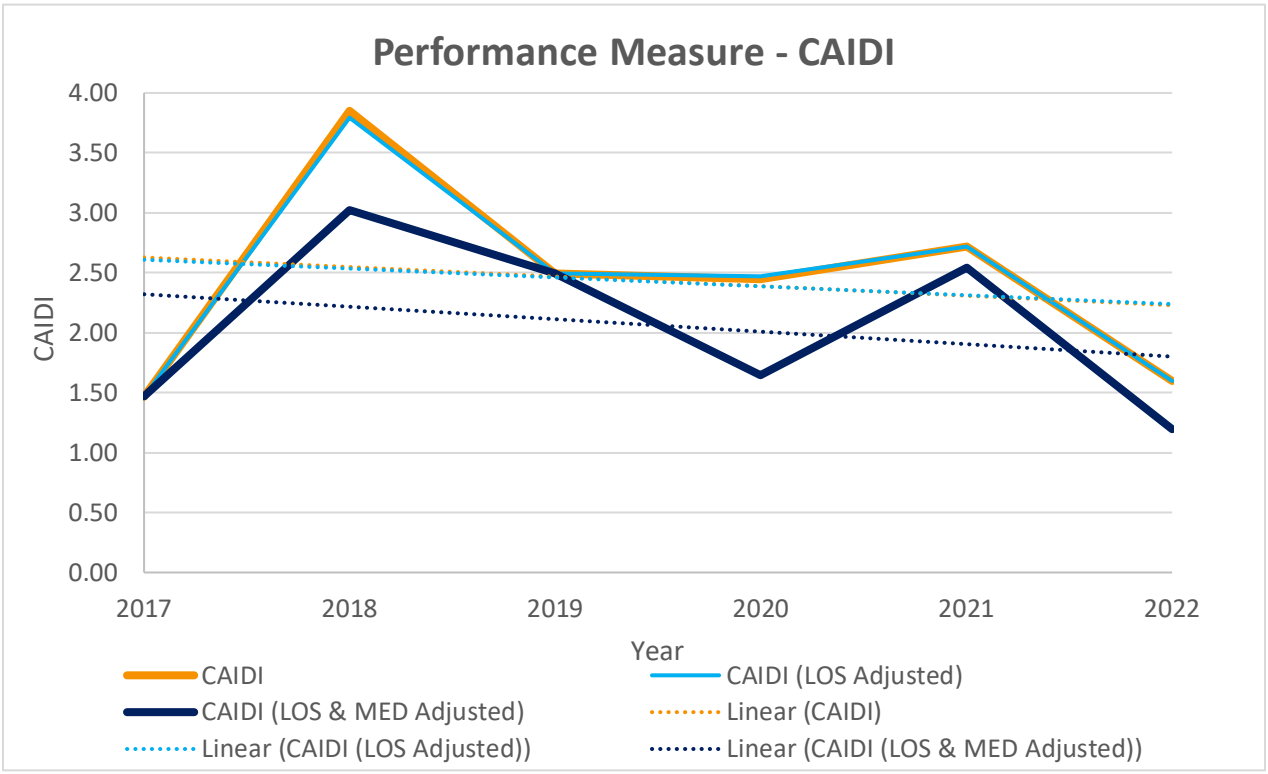


Figure 5.2-7: Performance Measure: CAIDI

InnPower's historical SAIDI and SAIFI performance have been lower than the distributor's targets with the exception of the recorded SAIDI in 2018. InnPower exceeded its SAIDI target in 2018 primarily as a result of faulty equipment and tree encroachment into OH distribution lines. Since then, InnPower has taken steps to readily identify, troubleshoot and sectionalize problem areas in order to minimize outages going forward.

InnPower also experienced a slight increase in SAIDI and SAIFI in 2020 as a result of defective equipment, tree encroachment, and adverse weather. However, these metrics remained within the allowable range. When excluding interruptions due to LOS and MED, InnPower's historical SAIDI, SAIFI, and CAIDI show an improving trend.

InnPower uses the SAIDI, SAIFI and CAIDI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. A number of investments in the System Renewal and System Service category that are planned to replace assets at the end of their service life and accommodate load growth will assist in maintaining system reliability. These include planned renewal of end-of-life assets such as poles, transformers, and switches, as well as substation rehabilitation.

Other initiatives that will reduce the number of controllable outages include:

- Testing and pre-treatment of wood poles.
- Proactive vegetation management.
- Ongoing inspection and maintenance of assets to identify and mitigate potential problems.

With InnPower being among the fastest growing utilities in Ontario, InnPower will continue to strive to provide reliable service to its 20,000+ customers while carefully managing its investment strategies for renewing its aging and deteriorating assets. InnPower is also continuing to make investments in system reliability through smart devices such as fault indicators, switches, control systems and outage response software, which will continue to help improve overall system reliability over the long term.

5.2.3.2.3 Outage Details for Years 2017–2022

Major Events

The applicant should also provide a summary of Major Events that occurred since the last Cost of Service (CoS) filing.

A "Major Event" is an event that is beyond the control of InnPower. Because these events occur infrequently and unpredictably, these events are not specifically forecast when designing and operating the distribution system. The following tables provide a summary of InnPower's Major Event Days (MEDs) over the historical period.

Table 5.2-9: Summary of MEDs over the Historical Period

Year	# of MEDs	Cause of MEDs
2017	0	N/A
2018	1	Adverse weather—wind
2019	0	N/A
2020	2	Lightning and adverse weather—wind.
2021	4	Adverse weather—wind (three major events) and adverse weather—tornado
2022	1	Adverse weather—wind

Table 5.2-10: List of MEDs over the Historical Period

Date	Customer Base Interrupted	Description
May 04, 2018	6,738	**Adverse Weather—Wind.** Barrie TS M3 locked out on May 4th at 16:47 and reclosed manually at 16:55. It again auto-reclosed at 17:22 and 17:27.
May 26, 2020	9,344	**Lightning.** On May 26, 2020, at 5:51pm, one of InnPower's main 44kV supplies from Hydro One indicated over 2,000 amperes on the red and white phases. The feeder was then removed from service. After patrolling the area, crews located a downed 44kV line on the 6th Line. It was reported that lightning had struck the pole, carried the current through the line and broke the wire off the insulator causing one phase to fall into another. Crews started making repairs at this location, while others continued to assess additional outages and respond to customer inquiries. Over the course of the night, a padmount transformer also failed requiring a replacement and a feeder serving Salem Road, McKay Road, Veterans Drive, and 4th Line was locked out. At around 2:30 am, the same 44kV supply from Hydro One locked out again. The team patrolled the area in sections and began troubleshooting by looking at fault currents and impedances. It was estimated that the fault was 10-15 km from the demarcation point from Hydro One. The team was able to identify a faulted arrestor in the CooksTown area and quickly isolated the section of line to ensure the site was left safe. All power was restored at 3:46 am.
November 15, 2020	9,823	**Adverse Weather – Wind.** On November 15, 2020, at 1:38 pm, one of InnPower's main 44kV supply (9M1/Alliston TS) from Hydro One locked out because of a tree contact, which caused an outage for 3,220 customers. Immediately after the storm started, this feeder was backed up from another 44kV feeder through InnPower's service territory. Crews located a downed distribution line on the 25th Sideroad, 10th Line, and 9th Line (37 locations in total reported outages). It was reported that a tree had struck the pole, carried the current through the line and broke the wire off the insulator, causing one phase to fall into another. Crews started making repairs at this location, while others continued to assess additional outages and respond to customer inquiries. Subsequently, multiple outages occurred because of high winds and storm conditions on the distribution side, which required patrolling in lightning and heavy rain conditions. Over the course of the night, most of the power to customers was restored and crews worked continuously for two days (in shifts) to restore 100% of customers.
April 30, 2021	11,921	**Adverse Weather—Wind.** On April 30, 2021, around 3:00 pm, wind intensity picked up causing a large tree to fall on InnPower's distribution lines. As a result, a large surge occurred on InnPower's distribution system, as well as the supply from Hydro One. Crews quickly responded and isolated the section of line and restored power to most customers around 5:30pm.

Date	Customer Base Interrupted	Description
		There were also significant repairs required on Corner Avenue due to a broken pole on the 9th Line and additional trees on the lines throughout the system. External crews were brought in to assist with restoration efforts.
July 15, 2021	2,193	**Adverse Weather—Tornado.** On July 15, 2011, at 2:38 pm, InnPower lost a major supply feeder from Barrie servicing 2,193 customers, due to an EF2 tornado. At 2:55pm, Environment Canada issued a Tornado warning for Barrie and Innisfil. By 4:48pm, InnPower had sectionalized and restored power to 1,088, leaving 1,105 customers without power. By 6:08 pm, 1,031 customers had been restored, leaving 74 customers without power (69 restored by 7:32 pm and five restored by 1:54 am). The main area damaged was Mapleview Drive between Yonge Street and 25th Sideroad, where many homes were damaged, and a new 44/27.6 kV pole line put up by InnPower was taken down.
December 2, 2021	2,574	**Adverse Weather—Wind.** On December 2nd at 8:00 am, wind intensity picked up causing a large tree to fall on the distribution line, leaving 482 customers without power. Crews quickly responded, cut and removed the tree from the lines and restored power by 9:59 am. The wind continued throughout the day and into the evening, causing two more significant outages. An outage occurred at 2:08 pm due to the 44kv tap being blown off the amp connection. 1957 customers were without power until the crews were safely able to install a jumper and restore power at 5:23 pm. Full repairs were completed the following day. The third outage affecting 130 customers occurred at 7:25 pm due to another tree being twisted in the three-phase circuit. The crew isolated the area and restored 126 customers by reclosing the blue phase by 10:55 pm. The remaining four customers were restored at 12:45 am on December 3rd. To complete the tree removal, an additional five customers had an outage from 10:20 pm to 12:45 am.
December 11, 2021	4,612	**Adverse Weather—Wind.** On December 2, 2021, at 2:45 pm, major outages occurred as a result of high winds causing extensive tree contacts and three broken poles. InnPower cleaned up and restored power as fast as possible by calling in additional resources to support restoration efforts.
June 16, 2022	14,244	**Adverse Weather—Wind.** On June 16, 2022, at 12:30 pm continuing until the morning of Saturday June 18, 2022, a major outage occurred throughout our area. High winds caused extensive tree contacts and the repair of a 44kv insulator. InnPower cleaned up and restored power as fast as possible by calling in additional resources to support restoration efforts.

Outages Experienced by Cause Codes

For each cause of interruption, a distributor should, for the last five historical years, report the following data:

- *Number of interruptions that occurred as a result of the cause of interruption.*

- *Number of customer interruptions that occurred as a result of the cause of interruption.*
- *Number of customer-hours of interruptions that occurred as a result of the cause of interruption.*

Table 5.2-11 presents a summary of total outages that have occurred within InnPower's service territory providing three different categorizations. The table values indicate a slightly increasing trend of outages with InnPower's service territory. A further breakdown by cause codes is provided in the following subsections.

Table 5.2-11: Number of Outages (2017-2022)

Categorization	2017	2018	2019	2020	2021	2022
All interruptions	156	179	178	242	181	198
All interruptions excluding LOS	156	177	177	241	181	198
All interruption excluding MED and LOS	156	176	177	239	177	197

Outages Experienced

Table 5.2-12 presents the count of outages broken down by cause code for the historical period. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption. InnPower continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 5.2-12 Outage Numbers by Cause Codes: Excluding MEDs

Cause Code	2017	2018	2019	2020	2021	2022	Total Outages	%
PLANNED								
1-Scheduled Outage	3	0	21	65	74	71	234	20.8%
UNPLANNED								
0-Unknown/Other	6	11	33	23	20	17	110	9.8%
2-Loss of Supply	0	2	1	1	0	0	4	0.4%
3-Tree Contacts	18	20	32	31	21	25	147	13.1%
4-Lightning	9	1	0	4	2	1	17	1.5%
5-Defective Equipment	69	64	44	53	14	26	270	24.2%
6-Adverse Weather	21	39	8	17	15	27	127	11.3%
7-Adverse Environment	2	3	0	0	0	0	5	0.4%
8-Human Element	6	12	7	8	4	4	41	3.6%
9-Foreign Interference	22	26	32	38	27	23	168	14.9%
Totals	**156**	**178**	**178**	**240**	**177**	**197**	**1,126**	**100.0%**

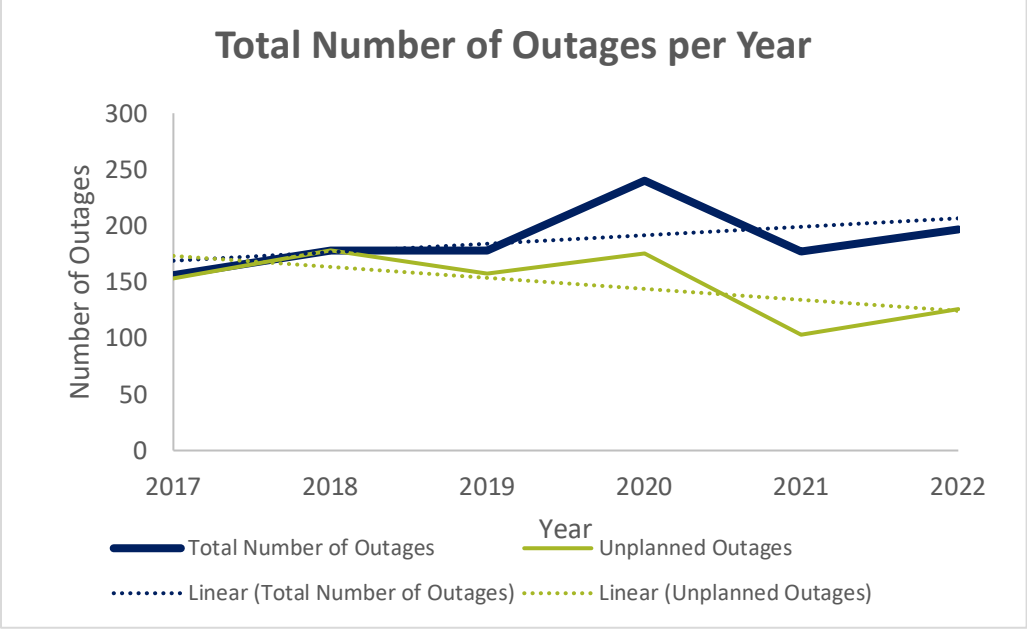


Figure 5.2-8: Total Number of Outages per Year

As shown in Table 5.2-12 and Figure 5.2-8, the number of scheduled(planned) outages has increased year on year. The planned outages are required to improve service over time for customers. The majority of these planned outages are taken to address defective equipment, which is the largest cause of unplanned outages.

The total number of interruptions over the historical period is shown in Figure 5.2-8, varying from a low of 156 to a high of 240, with the overall trend increasing in the period. This represents an average of 0.427 to 0.658 interruptions per day.

A summary of the causes of outages within InnPower's system is presented in Figure 5.2-9, along with the percentage of overall outage incidents attributable to each cause type.

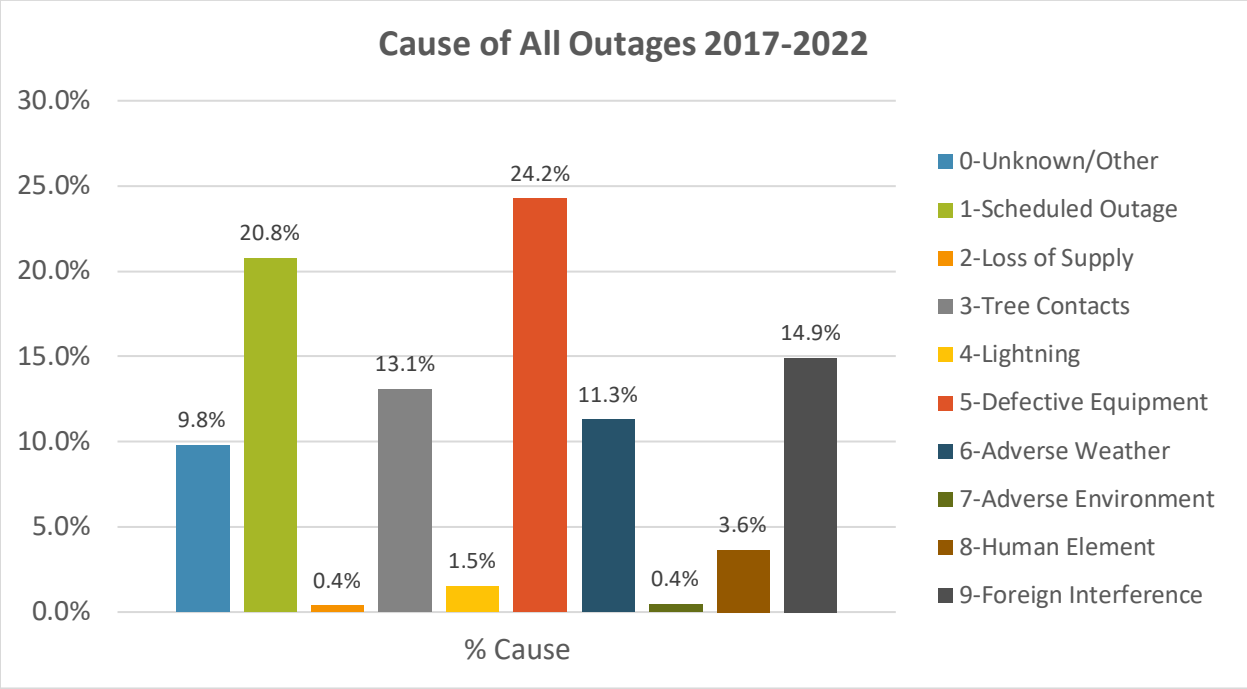


Figure 5.2-9: Percent of Outages by Cause Code

Defective equipment, scheduled outages, foreign interference, and tree contacts causes have been identified to be the four most common causes for outages on InnPower's distribution system over the historical period. Together, these causes contributed to 73% of the total number of outages from 2017 to 2022, excluding MEDs. Defective Equipment is the top contributing cause to the total outages experienced by InnPower. Defective Equipment accounted for 24.2% of the total outages experienced by InnPower over the historical period. These failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. InnPower has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. InnPower utilizes the ACA to assist in prioritizing investments in asset classes.

At 20.8%, Scheduled Outages is the second top contributing cause to the total outages experienced by InnPower. These outages are due to the disconnection of service for InnPower to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. InnPower aims to plan and execute capital work and maintenance appropriately in times that would affect minimal customers and with short durations.

Foreign Interference outages is the third top contributing cause to the total outages experienced at 14.9%. The outages contributing to the cause include animal interference, dig-ins, vehicle collisions and/or foreign objects. Some of these contributing factors can be minimized such as educating the public about calling before digging or installing animal guards in areas observed to have a high activity of animals, both of which InnPower continues to do. However, other factors such as vehicle collisions can happen at random and, depending on the extent and where the collision happens, may result in a large impact.

Tree Contacts was identified as the fourth top contributing cause to the total outages experienced by InnPower. Over the historical period, it has contributed to 13.1% of the total number of outages that

occurred. InnPower outsources tree trimming to a third-party entity, and in 2021, a new procedure and cutback approach was taken to improve safety and reliability.

Customers Interrupted and Customers Hours Interrupted

The number of Customers Interrupted (CI) is a measure of the extent of outages. Customer Hours Interrupted (CHI) is a measure of outage duration and the number of customers impacted. The tables and figures below provide the historical values and trends for both CI and CHI.

Table 5.2-13 Customers Interrupted Numbers by Cause Codes: Excluding MEDs

Cause Code	2017	2018	2019	2020	2021	2022	Total CI	%
0-Unknown/Other	12	3,916	3,488	8,622	442	6,076	22,556	21.9%
1-Scheduled Outage	3	0	406	308	555	246	1,518	1.5%
2-Loss of Supply	0	1,501	413	3,528	0	0	5,442	5.3%
3-Tree Contacts	317	1,014	1,367	4,236	400	2,322	9,656	9.4%
4-Lightning	125	9	0	12	2	9	157	0.2%
5-Defective Equipment	2,625	2,964	2,237	2,599	3,456	609	14,490	14.0%
6-Adverse Weather	5,306	5,488	1,017	4,296	1,578	5,851	23,536	22.9%
7-Adverse Environment	2	3	0	0	0	0	5	0.0%
8-Human Element	9,304	1,880	493	583	30	2,068	14,358	14.0%
9-Foreign Interference	131	500	2,424	199	7,278	565	11,097	10.8%
Totals:	**17,825**	**17,275**	**11,845**	**24,383**	**13,741**	**17,746**	**102,815**	**100.0%**

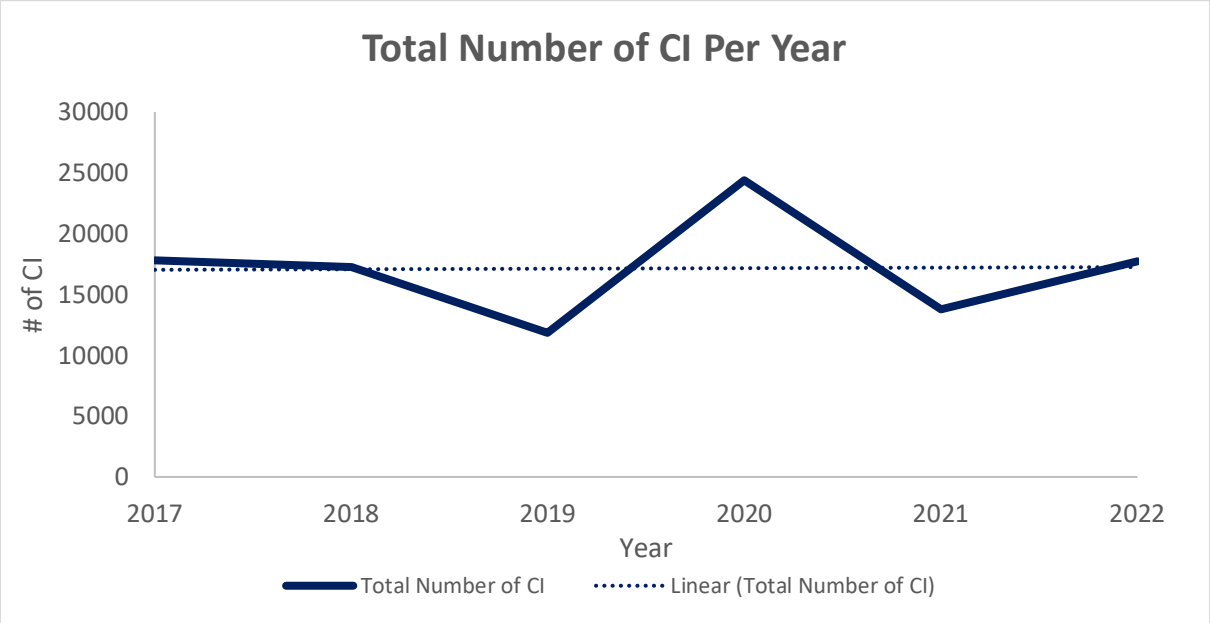


Figure 5.2-10: Total Number of Customers Interrupted by Year

Table 5.2-14 Customer Hours Interrupted Numbers (rounded) by Cause Codes – Excluding MEDs

Cause Code	2017	2018	2019	2020	2021	2022	Total CHI	%
0-Unknown/Other	36	8,868	3,035	3,365	296	2,119	17,719	8.5%
1-Scheduled Outage	2	0	781	610	759	748	2,900	1.4%
2-Loss of Supply	0	6,930	785	7,232	0	0	14,947	7.2%
3-Tree Contacts	566	2,836	4,701	7,408	1090	2,757	19,358	9.3%
4-Lightning	276	19	0	28	4	9	336	0.2%
5-Defective Equipment	5,878	8,928	2,112	7,796	9,347	902	34,963	16.8%
6-Adverse Weather	10,139	16,309	2,867	14,025	6,085	11,166	60,591	29.2%
7-Adverse Environment	4	7	0	0	0	0	11	0.0%
8-Human Element	8,984	7,881	576	873	60	1,912	20,286	9.8%
9-Foreign Interference	156	2,620	14,424	336	17,304	1,566	36,406	17.6%
Totals	26,041	54,398	29,281	41,673	34,945	21,179	207,517	100.0%

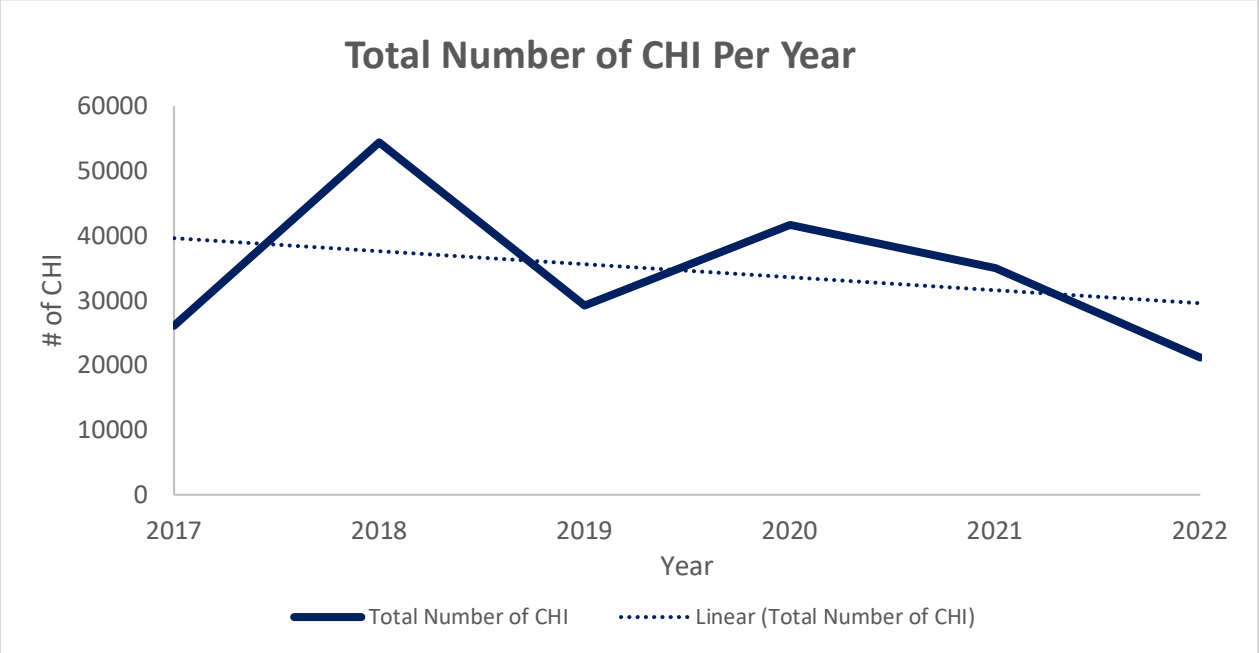


Figure 5.2-11: Total Number of Customers Hours Interrupted by Year

The trend for total number of CI over the historical period is stable and the trend for total number of CHI over the historical period is decreasing (i.e.: improving). The increase in CI observed in the year 2020 is largely driven by Adverse Weather and Unknown/Other, and the increases in CHI observed in 2018 and 2020 can be largely attributed to adverse weather.

When analyzing CI and CHI, Defective Equipment, Adverse Weather, Foreign Interference, and Human Element are among the top five cause codes for both CI and CHI. However, Unknown/Other is another major contributor for CI and Tree Contacts is another contributor for CHI.

- Adverse weather is beyond the control of InnPower. However, InnPower has and will continue to design and invest in storm hardening measures (i.e.: physical improvements that can make utility infrastructure more resistant to weather), which also aligns with one of the top priorities identified by InnPower customers. For example, InnPower takes design measures to ensure adequate storm guying and support during asset rebuilds and replacements. InnPower also has a Power Restoration Plan in place for different levels of outages to help guide restoration efforts and restore power to customers as quickly and safely as possible.
- Foreign Interference, which includes outages caused by animals, vehicles, dig-ins, or other foreign objects, are beyond the control of InnPower. However, InnPower does what it can to minimize these outages (i.e.: installing animal guards).
- Tree contacts are interruptions caused by faults resulting from tree contact with energized circuits. Although tree contacts are generally outside of InnPower's control, InnPower will continue to enhance its vegetation management program in order to mitigate the risk of outages caused by tree contacts.
- Human Element includes customer interruptions due to the interface of distributor staff with the distribution system. InnPower will continue to implement and encourage continued employee training and education in order to minimize interruptions caused by Human Element.
- Unknown/Other includes interruptions with no apparent cause that contributed to the outage. Over the forecast period, InnPower will continue to analyze system outages on a case-by-case basis in order to identify the root cause and develop solutions as appropriate.

The top cause code that can be controlled and managed by InnPower is Defective Equipment. As previously noted, there are several ongoing and planned efforts to manage the number of controllable outages and continue meeting reliability targets. These efforts include ongoing inspection and maintenance of assets to identify and mitigate potential problems and planned capital investment programs to replace assets before experiencing a failure that may cause an outage (i.e.: InnPower's planned transformer, pole, recloser, switch, and switchgear replacement programs).

5.2.3.3 Distributor Specific Reliability Targets

As established in the Report of the OEB: Electricity Distribution System Reliability Measures and Expectations, distributors' SAIDI and SAIFI performance is expected to meet the performance target set out in the Scorecard. Distributors who wish to establish performance expectations based on something other than historical performance should provide evidence of their capital and operational plan and other factors that justify the reliability performance they plan to deliver. Distributors should also provide a summary of any feedback from their customers regarding the reliability of the LDC's distribution system. Distributors who wish to use SAIDI and SAIFI performance benchmarks that are different than the historical average must provide evidence to support the reasonableness of such benchmarks.

The performance baseline targets for SAIDI and SAIFI over the historical period were set based on the average performance over the 2012-2016 period, excluding LOS and MEDs. This corresponded to a target of 2.15 for SAIDI and 1.37 for SAIFI.

In addition to meeting the performance baseline targets, SAIDI and SAIFI trending is done by comparing the performance baseline targets against the most recent five-year rolling average (i.e.: average of the most recent five-year performance, updated annually). This information is reported annually as part of the OEB Scorecards.

5.3 Asset Management Process

A distributor must use an asset management process to plan, prioritize, and optimize expenditures. The purpose of the information requirements set out in this section is to provide the OEB and stakeholders with an understanding of the distributor's asset management process, and the links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

This section provides an overview of InnPower's AM process, a description of assets managed by InnPower, and a presentation of InnPower's asset lifecycle optimization procedures and practices.

5.3.1 Planning Process

5.3.1.1 Overview

A distributor must provide an overview of its planning process (this includes a distributor's capital expenditure planning process) that has informed the preparation of the distributor's five-year capital expenditure plan (a flowchart accompanied by explanatory text may be helpful).

InnPower's AM process proactively identifies, manages, and mitigates risks within their electricity distribution system, thereby allowing InnPower to achieve a desired level of service for their customer base at the best appropriate cost as accepted by their customers.

Integrated within InnPower's AM process are AM Objectives that are largely driven by a combination of InnPower's corporate mission, vision, values, and strategic goals (previously described in section 5.2.1.1) and relevant legislative and regulatory obligations, including the OEB's RRF Performance Outcomes and requirements outlined in the DSC and the OEB Act.

InnPower is a relatively young LDC that purchased many of its distribution assets from Ontario Hydro (HONI) in 1993. InnPower is anticipating a customer increase of at least 34% over the next five years (as shown in section 5.3.2.1) and continued growth beyond this planning horizon (i.e.: more than 100% over the next 15 to 20 years). To accommodate high load growth requirements and ensure compliance with regulatory and distribution system requirements, InnPower has established the following planning objectives derived from its AM philosophy:

4. Ensuring public and worker safety;
5. Meeting legislative requirements;
6. Mitigating environmental risk;
7. Maintaining system reliability;
8. Managing costs; and
9. Accommodating organic load growth.

These AM objectives form the high-level philosophy framework for InnPower's capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan needed to sustain InnPower's electrical distribution system. The objectives guide InnPower in making effective capital investment decisions, which inherently make the best use of assets and maximize their value to the company. The objectives identify an initial starting point and continue to be developed, enhanced, and adjusted as necessary to align with the business environment that the

company operates in and help encourage the process of continuous improvement. The AM objectives have been integrated into InnPower's capital investment process to prioritize investments.

InnPower's AM process shown in Figure 5.3-1 demonstrates its high-level AM direction, principles, and mandatory requirements. Arrows show the flow of the process and the interconnections between the various processes, inputs, and outputs. The AM process interprets the company's vision, mission, and values and serves as the connection between top-level corporate and strategic goals and objectives through to the bottom-level AM practices.

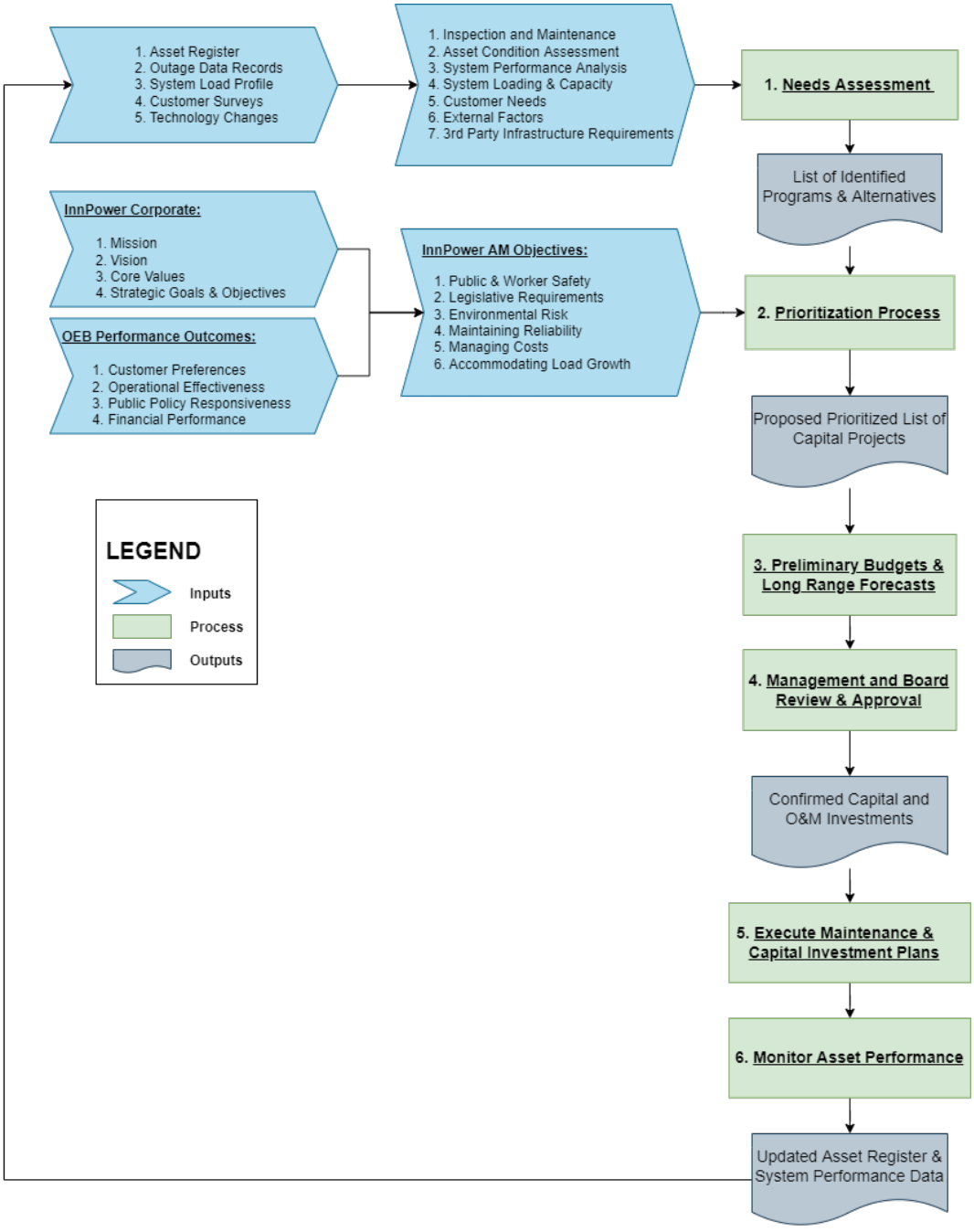


Figure 5.3-1: InnPower Asset Management Process

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Most of these investments are triggered by one or more of these three situations:

- A performance decline in the areas of supply system reliability, power quality, or safety.
- An increase in operating and maintenance costs associated with aging and deteriorating assets.
- Anticipated growth in demand requiring capacity upgrades.

In any of these cases, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, when system investments are not made on time it raises the risk of performance targets not being achieved and will also result in non-optimal operation. Optimal operation of the distribution system is achieved when right-sized investments in renewal and replacement (capital investments) and in asset repair, rehabilitation, and preventative maintenance are planned and implemented based on a just-in-time approach. In summary, the overarching objective of the AM strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

InnPower employs a condition-based AM strategy. This strategy determines the likelihood of an asset failure based on its condition. A yardstick of asset health indices is commonly used to quantify conditions. InnPower's AM strategy covers the full life cycle of a fixed asset, from the preparation of the asset specification and installation standards to the scope and frequency of preventative maintenance during the asset's service life, and finally to the determination of the asset's end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest operating costs. The best-in-class AM strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that are easily audited and inspected by regulators.

InnPower's AM process is established such that activities are coordinated to ensure assets are optimally achieving the company's corporate and AM objectives. Conceptually, the process includes items such as setting out the criteria for optimizing and prioritizing AM objectives, lifecycle management requirements of the assets, stating the approach and methods by which the assets are managed (including performance, condition, and criticality assessment), the approach to the management of risk, and identifying continuous improvement initiatives. InnPower's AM process is an iterative one that is regularly updated with the latest sets of data and information to ensure that InnPower is initiating capital projects at the right time. As well as using this process to develop its original five-year DSP capital plan, InnPower also uses it as an annual capital expenditure planning process to update its budget and plan for the following year.

Key elements of InnPower's AM process used to prepare its capital expenditure plan are identified in the following sections, including objectives, data inputs, preliminary process steps, and outputs.

5.3.1.2 Important Changes to Asset Management Process Since the Last DSP Filing

A distributor should provide a summary of any important changes to the distributor's asset management process (e.g.: enhanced asset data quality or scope, improved analytic tools, process refinements, etc.) since the last DSP filing.

Since issuing its 2017 DSP, InnPower has changed personnel and undertaken a fundamental review and update of its business plans and corporate focus. These changes have been incorporated into

InnPower's AM process. The changes have been fairly minor, centered around enhancing the existing process and the data available to help InnPower in its decision-making process.

In addition, because of enhancements made to its inspections and maintenance procedures (further detailed in section 5.3.3), InnPower now has access to improved asset data which has been tied into system planning and decision-making. The improved procedures and data access have enabled InnPower to manage its assets based on more robust and quantified justifications.

5.3.1.3 Process

A distributor should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), optimize, and pace the execution of investments over the term of the DSP. A distributor should be able to demonstrate that it has considered the correlation between its capital plan and customers' needs. A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures (e.g.: the risk/benefit of a reactive service transformer replacement program instead of proactively replacing service transformers).

A distributor should demonstrate how it does grid optimization using an approach that considers the distributor's whole system. This should include where applicable, assessing the use of non-wires alternatives, distributed energy resources, cost-effective implementation of distribution improvements affecting reliability and meeting customer needs at acceptable costs to customers, other innovative technologies, and consideration of distribution rate funded Conservation and Demand Management (CDM) activities.

A distributor must also demonstrate that it has a planning process for future capacity needs of the distribution system, which must include, among others, increased adoption of electric vehicles. On November 2, 2022, the OEB posted the "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG), which provides guidance in the development of demand forecasts to increase consistency among distributors. Distributors should consider this guidance when developing their load forecasts. The guidance recommended a sensitivity analysis to capture uncertainty in the demand forecast and noted "one of the evolving components with respect to the demand for electricity is electrification which is expected to change the growth patterns such as they are not well represented by historical trends."

2021 CDM Guidelines:
Distributors are required to make reasonable efforts to incorporate consideration of CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. A distributor's distribution system plan should describe how it has considered CDM in its planning process.

InnPower uses input data and information to enable it to determine its operating and capital expenditure plans. As illustrated in Figure 5.3-1, this is done in a multistage process that is detailed below.

Step 1: Needs Assessment

Firstly, using input data such as asset condition analysis, system performance, customer engagement results, and customer priorities, a NA is performed. This allows InnPower to identify high-level projects and programs that it could undertake to address the needs required over a five-year period based on

the best available information for each year. As part of this, an evaluation of the different options to address the need is also performed. This includes looking at options of full replacement, refurbishments, or doing nothing, and investigating pacing requirements and resource availability, and determining whether CDM is a feasible option to meet the identified system need. This allows InnPower to streamline the projects and programs it will undertake with a recommended list of programs and alternatives. In addition, InnPower considers future capacity needs in regard to potential EV uptake. InnPower has not seen a large uptake in EV demand in its territory. For any new connections, InnPower engages the third-parties to understand any information that indicates there will be an uptake in EV's, collates the requirements, and assesses if any capacity adjustments or allocations are required. Additionally, for any new loads, InnPower accounts for the load for potential EV's in its capacity planning.

Additionally, when assessing its options for each project, InnPower considers whether a non-wire alternative (NWA) is a feasible option. However, currently from the forecast growth InnPower is seeing, the load and capacity needs cannot be feasibly met by NWAs. During the IRRP, NWAs were considered, however this option was not recommended as it would not address the needs. InnPower will continue to assess NWA during the forecast period.

The projects and programs that InnPower selects for its capital budget are the ones that are required to ensure the safety, efficiency, and reliability of its distribution system, and to complete other projects as needed to allow InnPower to carry out its obligation to distribute electricity within its service area as defined by the DSC. This includes:

- System Access projects such as development and county/municipal pole relocation projects are identified throughout the year by external stakeholders. These projects are non-discretionary and are budgeted and scheduled to meet the timing needs of the external proponents.
- System Renewal projects are discretionary. The project needs for a particular period are supported by a combination of asset inspection, individual asset performance, and the ACA.
- System Service projects are discretionary and ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are promptly dealt with. Some of these projects are also informed through the regional planning process.
- General Plant projects, such as fleet vehicle acquisition or replacement, software/hardware, etc., are discretionary and are identified internally by specific departments (engineering, customer service, finance, operations, administration, etc.) and supported through a combination of inspection and maintenance activities, utility best practice, regulation, and manufacturer recommendations.

Step 2: Prioritization Process

Following the identification of recommended projects and programs and alternatives to address identified needs, a prioritization process is undertaken. At this stage, further inputs are considered including InnPower's AM objectives, corporate goals, and the OEB performance outcomes. This information, along with the programs identified, are used to identify specific projects within the programs and identify a prioritized list of projects.

Non-discretionary projects are selected and prioritized based on externally driven schedules and needs. Most System Access projects fall into this category and may involve multi-year investments to meet proponent needs. A system of project prioritization is applied that considers growth rates, safety, reliability, performance, condition, age, and other drivers internal or external to InnPower. Material

investment information provided in Appendix A includes a copy of a capital project summary template that InnPower uses as a means of capturing project-specific information.

Discretionary projects are selected and prioritized based on value and risk assessments for each project. Most System Renewal, System Service, and General Plant projects fall into this category. Some projects, such as the Pole Replacement Program and Transformer Replacement Program, typically involve multi-year program investments to meet AM needs. To increase the objectivity of its project prioritization process, InnPower assigns weights to its AM objectives, as depicted in Figure 5.3-2.

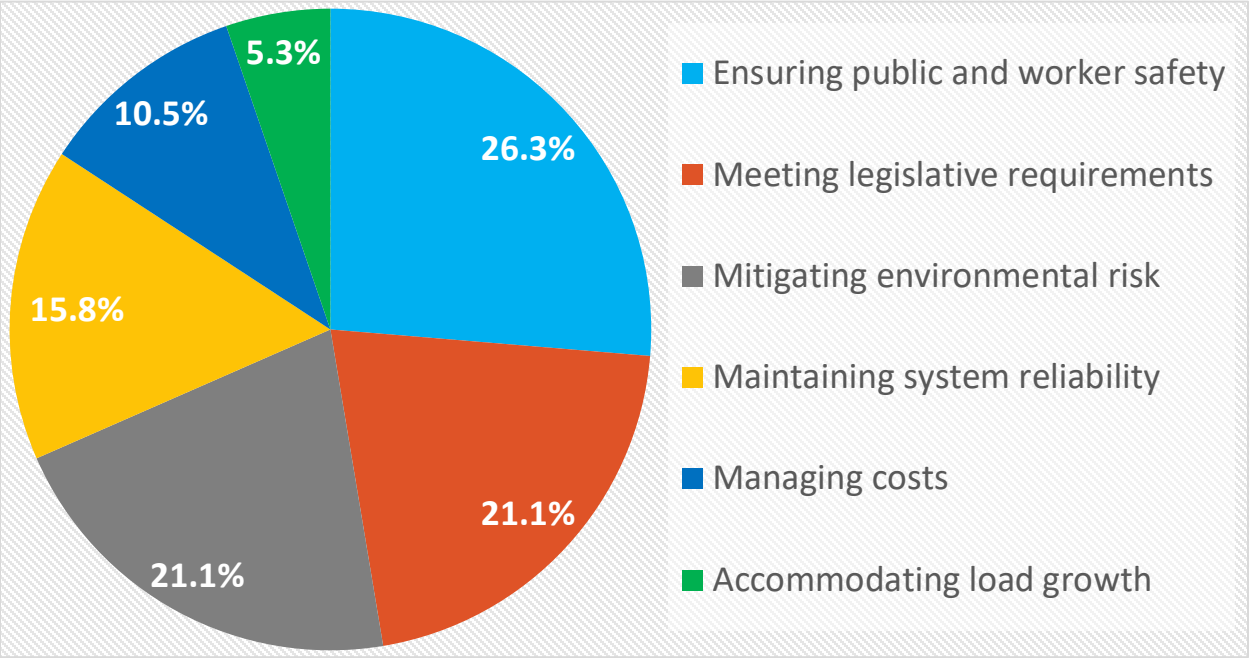


Figure 5.3-2: Weighted Priorities for Asset Management and Capital Expenditure Planning

Projects are then scored for each of the capital expenditure planning objectives using the probability and consequence risk matrix depicted in Table 5.3-1. Multiplying the result by the objective weight and summing each of the six objectives provides an overall score for each project.

Table 5.3-1: Probability and Consequence Risk Matrix

	CONSEQUENCE				
PROBABILITY	SMALL	MODERATE	SIGNIFICANT	SEVERE	WORST CASE
MOST LIKELY	9	24.5	66.5	180.8	491.4
VERY LIKELY	7.5	20.4	55.4	150.6	409.5
LIKELY	5	13.6	36.9	100.4	273.0
UNLIKELY	2.5	6.8	18.5	50.2	136.5
VERY UNLIKELY	1	2.7	7.4	20.1	54.6

System Renewal projects and some System Service projects are subdivided into those assets that are expected to fail (i.e.: critical assets) and those assets for which replacement is a matter of economic value (i.e.: recommended for replacement). Rate impacts are considered on a holistic level to ensure the alignment of overall budgets with company objectives. Where the rate impact is too high, lower-priority projects may be reconsidered and deferred to later years to balance out the rate impacts.

Step 3: Preliminary Budgets & Long-Range Forecasts

Once the list of prioritized projects and programs is confirmed, it is then used to inform the preparation of the preliminary capital and operating budgets and long-range forecasts. InnPower compiles budget information for the three major components of the budgeting process:

1. Revenue forecasts;
2. Operating, Maintenance, and Administration (OM&A) expense forecast.
3. Capital budget forecast.

1. Revenue Forecast

InnPower's revenue forecast is based on forecasted energy consumption, peak load, and customer counts for the 2024 test year. InnPower prepares a weather-normalized load forecast by customer class and monthly customer class data for weather-sensitive customer classes using the regression analysis and by average usage and forecasted customer growth for the non-weather-sensitive customer classes. The forecast results are then used to calculate the 2024 test year revenue requirement at existing rates and proposed rates.

2. OM&A Expense Forecast

InnPower allocates available person-hours to the various OM&A programs and activities planned and budgeted for each year. Any remaining hours are allocated to identified capital projects. InnPower employs contract labour, utilizing long-term contracts as well as on-demand labour, and such contract work is determined based on the level of workload and expertise required. InnPower reviews and establishes the budget based on historical trends and known factors as opposed to simply applying an arbitrary inflation factor. Labour costs are in accordance with InnPower's Collective Agreement.

3. Capital Budget

InnPower's AM process identifies the capital projects required and projected to be required over a five-year period based on the best available information for each year. The capital budget forecast is significantly influenced by growth, customer requests including road works, reliability and the conversion of aging infrastructure, and the cost of support systems. All proposed capital projects for the bridge year and test year will be completed and in service in their respective year. InnPower acknowledges that, where the priority of projects changes, or factors outside of its influence change, InnPower may be required to re-evaluate the future year's capital project forecast.

Step 4: Management and Board Review & Approval

Once the preliminary capital budget and long-range forecast have been approved by senior management, it is presented to InnPower's Board of Directors as follows:

1. The senior management team presents a Preliminary Capital Budget and long-range forecast at the next meeting of the Board of Directors.
2. The feedback received from the Board of Directors is shared with the various department managers to make any revisions to the budget and long-range forecast, as necessary.
3. The revised final version is then presented to the Board of Directors for approval.
4. It is then the responsibility of the Board of Directors, on behalf of the stakeholders, to approve the budget.

Once the Board of Directors approves the budget, the budget amounts do not change but rather provide a plan against which actual results may be evaluated. In addition to the capital needs of the

distribution system, InnPower plans for the required maintenance of its assets considering both performance and safety.

Step 5: Execute Maintenance and Capital Investment Plans

Once the projects and programs and associated operating and capital spending have been approved, the projects are monitored from initiation to execution. Capital is monitored and evaluated through InnPower's Prophix software to ensure that budgets are met. Inspection and maintenance works are monitored and evaluated using the following two metrics:

- Dollars spent compared to budget.
- Percent completion of cycle map.

Step 6: Monitor Asset Performance

Once the projects are complete the assets are monitored on their performance through regular maintenance and inspection programs, and updated information is fed back into the asset database.

5.3.1.4 Data

A distributor should identify, describe, and provide a summary of the data used in the processes above to identify, select, prioritize, optimize, and pace the execution of investments over the term of the DSP (e.g.: asset condition by major asset type and reliability information).

InnPower uses several datasets and inputs to assess the status of its distribution system assets and to assist in determining the capital and operational investments to be made in the system. This ranges from ACA, customer engagement, and inspection and maintenance results to what its AM objectives are and how they link to the OEB's performance outcomes and any external factors. Some of the key elements are explained in further detail below.

Key Data Inputs

Key data inputs utilized as a part of InnPower's AM process include asset information, outage data records, system utilization and loading, customer survey results, and information on innovative technologies being implemented in the industry. Much of this information is stored within an asset database which is kept up to date with current information. Table 5.3-2 below summarizes the components of InnPower's asset database that is available and used for planning purposes.

Table 5.3-2: Information Comprising InnPower's Asset Database

Asset Database			
Component	**Owner/Location**	**Asset Information**	**Data Format**
GIS	Engineering	> Pole location and age > Circuit conductor size, voltage, and phase(s) > OH switch, transformer, switchgear location, and nomenclature	Electronic data

Asset Database			
Component	**Owner/Location**	**Asset Information**	**Data Format**
Spreadsheets	Engineering	> Reclosers > Padmounted switchgear > Pole database > Transformer information > SCADA-Mate switches > 44 kV switches	Electronic data
NorthStar database	operations	> Transformer data	Electronic data
Financial system	Finance	> IFRS asset value > Asset useful life studies	Paper reports, electronic database
	Finance	> Purchase history > Installation history > Removal history	Paper forms
ACA report	Engineering	> Annual ACA	Spreadsheet
Outage history	Engineering	> SAIFI and SAIDI stats database > Historical data on customer interruptions caused by equipment failure	Paper/spreadsheet
Maintenance records	Engineering/ Operations	> Transformers, switchgear, poles, stations	Electronic data
Inspection records	Engineering/ Operations	> Transformers, switchgear, poles, stations	Electronic data
Asset utilization records	Engineering	> Station and feeder loading	Spreadsheet
General Plant	Operations	> General Plant information	Paper/spreadsheet
	IT	> General Plant information	Paper/spreadsheet
	Finance	> General Plant information	Paper/spreadsheet

Inspection and Maintenance

InnPower regularly undertakes maintenance and inspection practices to maintain customer reliability and power requirements in the system. Inspection, maintenance, and operational data are collected and stored which is used to support InnPower's operating and capital expenditure plans.

Completion of the inspection and maintenance programs is not only a matter of compliance, but the results from the inspection and maintenance programs also allow for a continual update of the asset database. The programs allow for assets to be inspected and assessed for any necessary actions that need to be taken promptly in a proactive approach. InnPower's inspection and maintenance programs are audited annually as required by Ontario Regulation 22/04. Further information on InnPower's maintenance and inspection practices can be found in section 5.3.3.2.

Asset Condition Assessment

An ACA was completed in October 2021 for InnPower's station and distribution assets, which uses conditions to identify those assets most likely to fail. The ACA involves the interpretation of condition and performance data of key assets to assess the overall condition of the asset and identify assets

that have the highest probability of failure. The ACA is a key supporting tool for developing an optimized lifecycle plan for asset sustainability. The results of the ACA were incorporated into a formalized capital plan and have resulted in the revision of project prioritization within the service area for the forecast period. Further information on InnPower's ACA can be found in section 5.3.3.2 and Appendix J.

System Performance Analysis

InnPower places a high level of importance on ensuring distribution system reliability meets the expectations of its customers. InnPower strives to continually improve its processes for collecting, measuring, analyzing, and using outage information within its AM process to effectively manage distribution system reliability in its service territories.

Outage causes are tracked and analyzed by outage cause codes. This allows InnPower to identify trends in causes of outages and allows for this information to feed into its prioritization and evaluation process when developing its capital investment plans. The analysis is used to inform the development of O&M programs and capital expenditure plans for each year.

System Loading and Capacity

Load forecasting and capital growth planning continue to be the underlying basis for the near- and longer-term capital requirements for new or enhanced capacity. The loading and capacity information help to identify system needs and constraints. The information is collected on system peak loading at many points in the system and the data is analyzed to measure the risk of system overloading and to mitigate any concerns.

Given the current and forecasted load growth over the five-year planning horizon (detailed further in section 5.3.2.1), major upgrades and system expansions are planned over the forecast period.

Customer Needs

InnPower focuses on providing reliable, efficient, and safe electricity to its customers. As part of the investment planning process, InnPower conducts customer surveys to understand customer needs. Customer needs also address requirements for new customer connections and/or modification to existing customer connections and incorporate them early in the AM process.

Additional information on InnPower's customer engagement process and findings are included in section 5.2.2.1 of this DSP. Customer survey results are also included in Appendix B.

External Factors

External drivers may sometimes influence InnPower's decision-making in determining the optimal plans for their system. External drivers include:

- **Political:** Governments have their directions and strategies that InnPower needs to be mindful of and to be in alignment with.
- **Economic:** Economic growth and decline within InnPower's service area as well as the shift of business operations within residential units.
- **Social:** Changes in the environment that illustrate customer needs and wants.
- **Technological:** Innovation and development within the electrical/utility sector which includes automation, technology awareness, electric vehicle penetration, distributed energy resources (DERs), battery energy storage systems (BESS), and new services.

- **Environmental:** Ecological and environmental aspects that can affect InnPower's operations or demand which include renewable resources, weather or climate changes, and utility responsibility initiatives.
- **Regulatory/Legal**: Legal allowances and/or changing requirements from the OEB as well as additional legal operations such as health and safety requirements, labour laws, and consumer protection laws.

InnPower continues to remain cognizant of these external drivers when developing its capital and maintenance plans.

Third-Party Infrastructure Requirements

InnPower has an obligation, as per the DSC regulation, to address investments in third-party infrastructure. Any requirements by the Town or other third parties to develop or modify the system are considered. This also includes government programs, such as the AHSIP aims to connect every region in Ontario to reliable, high-speed internet by the end of 2025.

InnPower Corporate

Another input into the process is InnPower's corporate mission, vision, core values, and strategic goals and objectives, which are described previously in section 5.2.1.1.

OEB Performance Objectives

InnPower's AM process is also informed by the four key objectives established in the OEB's *RRF for Electricity*:

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

AM Objectives

InnPower's AM objectives, as outlined previously in section 5.3.1.1, are another key input into InnPower's AM process. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain InnPower's electrical distribution system. The objectives guide InnPower to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in and help to encourage the process of continuous improvement. The AM objectives have been integrated into InnPower's capital investment process to prioritize investments for several years including the test year.

5.3.2 Overview of Assets Managed

Assessment of DSPs requires a comprehensive understanding of all aspects of the assets managed by a distributor. Distributors may vary in terms of the level of detail that it chooses to record for their distribution assets, but the expectation is that in assessing the condition of major assets (e.g.: station transformers and poles), solely using asset age is not sufficient.

This section presents a description of InnPower's service area, a summary of the system configuration, the results of the ACA, and InnPower's system utilization relative to planning criteria.

5.3.2.1 Description of Service Area

A distributor should provide an overview of its distribution service area (e.g.: system configuration; urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent to supporting its capital expenditures over the forecast period.

5.3.2.1.1 Overview of Service Area

InnPower has a service area of 292 km^2, which includes the entire Town of Innisfil and a portion of the South Barrie lands. The service area is mostly rural (215 km^2), with small urban centres (77 km^2) including the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point (InnPower's service territory is depicted in Figure 5.2-1). The South Barrie lands are two greenfield development areas, namely the Hewitt and Salem lands.

InnPower's service area is within the temperate climate region of Southern Ontario. Throughout the year, the temperature typically varies from -12°C during the winter to 25°C in the summer and is rarely below -21°C or above 29°C. Both OH and underground (UG) distribution systems are employed in InnPower's service territory. Currently, approximately 78% of InnPower's primary conductors are OH and the remaining 22% are UG.

Innisfil and South Barrie are both areas of high residential growth, which has created the need for additional investment into InnPower's system.

5.3.2.1.2 Customers Served

Table 5.3-3 below illustrates an increasing trend in InnPower's total customer base over the historical period, divided into residential, general service less than 50 kW, and general service greater or equal to 50 kW. Over the historical period, InnPower's customer base has grown by an average of 3.6% annually. With InnPower continuing to be among the fastest-growing utilities in Ontario, this trend is expected to continue over the forecast period.

Table 5.3-3: Historical Customer Base

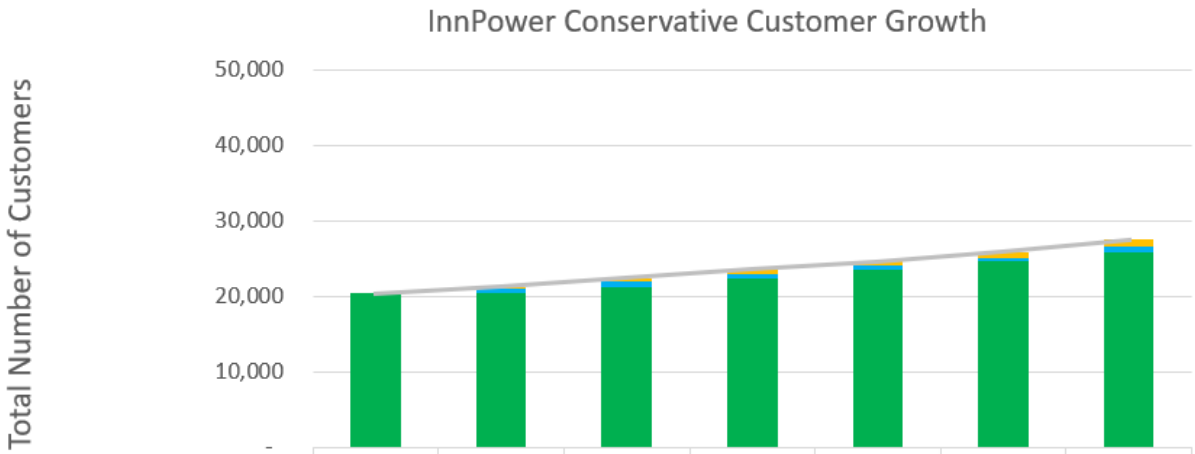
Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2017	16,103	1,034	91	17,228
2018	16,966	1,107	90	18,163
2019	17,409	1,140	83	18,632
2020	18,037	1,165	79	19,281
2021	18,415	1,210	78	19,703
2022	19,170	1,263	80	20,513

InnPower's customer growth is a key input and driver for its current and future capital expenditures. To help inform planning and design the system accurately, InnPower has developed two customer growth projections over the five-year forecast: a conservative growth projection and an optimistic (non-conservation) growth projection:

- **Conservative Case:** In this case, InnPower has considered the County of Simcoe's Municipal Comprehensive Review (MCR) and historical growth to apply a conservation factor to the number of units submitted by developers.
- **Optimistic (Non-Conservative) Case:** This case corresponds to the actual load demand submitted by developers for the next five years, with the MCR and market demand factor, with the remaining number distributed across the next five-year horizon after the first energization request.

Additional information on these projections and underlying assumptions can be found in InnPower's Strategic Plan attached as Exhibit 1-1-5 to this COS Application.

The conservative growth projection is provided in Figure 5.3-3. Under this scenario, InnPower is expecting its customer base to grow by an average of over 5% annually over the forecast period, and by the year 2028, InnPower expects its customer base to be approximately 34% higher relative to its current customer base. Innisfil and South Barrie in particular are both areas of high residential growth, which has created the need for additional investment into InnPower's system over the forecast period.



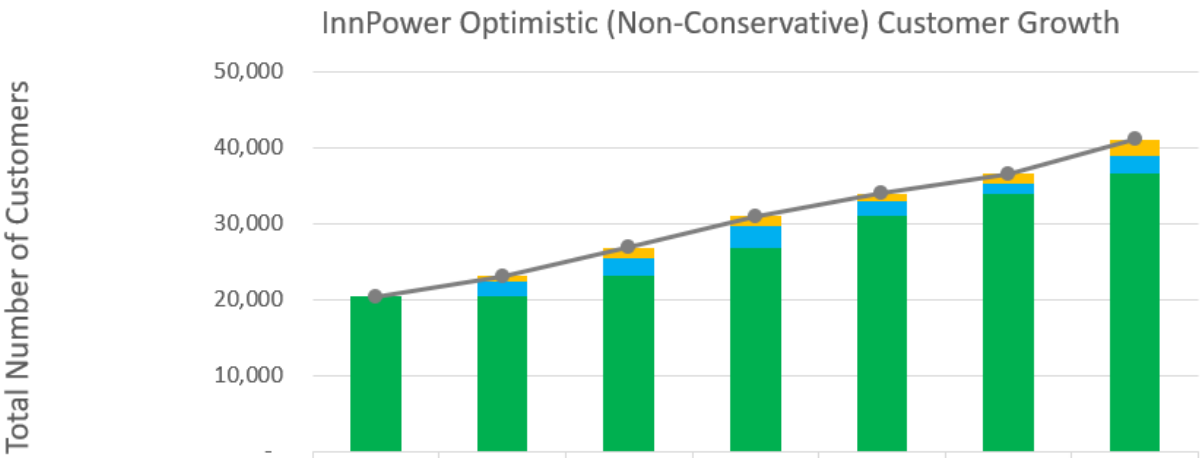
	2022	2023	2024	2025	2026	2027	2028
Innisfil Annual Growth	-	331	473	524	544	727	979
Barrie Annual Growth	-	533	610	637	537	508	636
Actual Existing	20,508	20,508	21,372	22,456	23,617	24,698	25,932
Total Growth	20,508	21,372	22,456	23,617	24,698	25,932	27,547

Figure 5.3-3: InnPower Conservative Projected Customer Growth[5]

Under the optimistic (non-conservation) growth projection, InnPower is expecting its customer base to grow by an average of over 12% annually over the forecast period, as shown in Figure 5.3-4. By the

[5] **NOTE:** The 2022 customer numbers utilized in the customer growth projections (20,508) correspond to estimates utilized prior to closing year-end. These are slightly different relative to the actual number of customers recorded after year end was closed (20,513). The actual number of customers recorded post-year end will be filed as part of the OEB's reporting and record keeping requirements.

year 2028, InnPower expects its customer base to be over 100% higher relative to its current customer base.



	2022	2023	2024	2025	2026	2027	2028
Innisfil Annual Growth	-	820	1282	1258	1032	1295	2217
Barrie Annual Growth	-	1842	2433	2924	1912	1322	2252
Actual Existing	20,508	20,508	23,170	26,885	31,067	34,011	36,628
Total Growth	20,508	23,170	26,885	31,067	34,011	36,628	41,097

Figure 5.3-4: InnPower Optimistic Projected Customer Growth

5.3.2.1.3 System Demand & Efficiency

Table 5.3-4 shows the annual season and average peak demand in kW for InnPower's distribution system.

Table 5.3-4: Historical System Peak Demand Statistics

Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2017	50,927	51,036	44,231
2018	52,732	58,965	49,084
2019	54,784	59,938	46,996
2020	51,178	65,476	50,379
2021	52,272	62,170	49,883
2022	56,530	63,546	54,433

InnPower experiences a system peak during the summer months, and the increasing trend observed over the historical period is largely attributed to InnPower's growing customer base. Variances in the seasonal peaks are also driven by variations in weather temperature in both winter and summer and loading impacts associated with the number of degree days.

With InnPower continuing to be among the fastest-growing utilities in Ontario, the system peak demand is expected to continue growing over the forecast period. To evaluate and design the system accurately, InnPower has completed a sensitivity analysis to evaluate projected system peak demand.

Aligned with the customer growth projections described above, InnPower has evaluated both a conservative projected peak demand and an optimistic (non-conservation) projected peak demand.

Under the conservative case, the forecast system peak in 2028 is expected to be approximately 58% greater than the recorded peak in 2022. Under the optimistic case, the forecast system peak could grow up to 86% in 2028 relative to 2022. In both cases, additional investments into InnPower's system are needed to accommodate this growing demand.

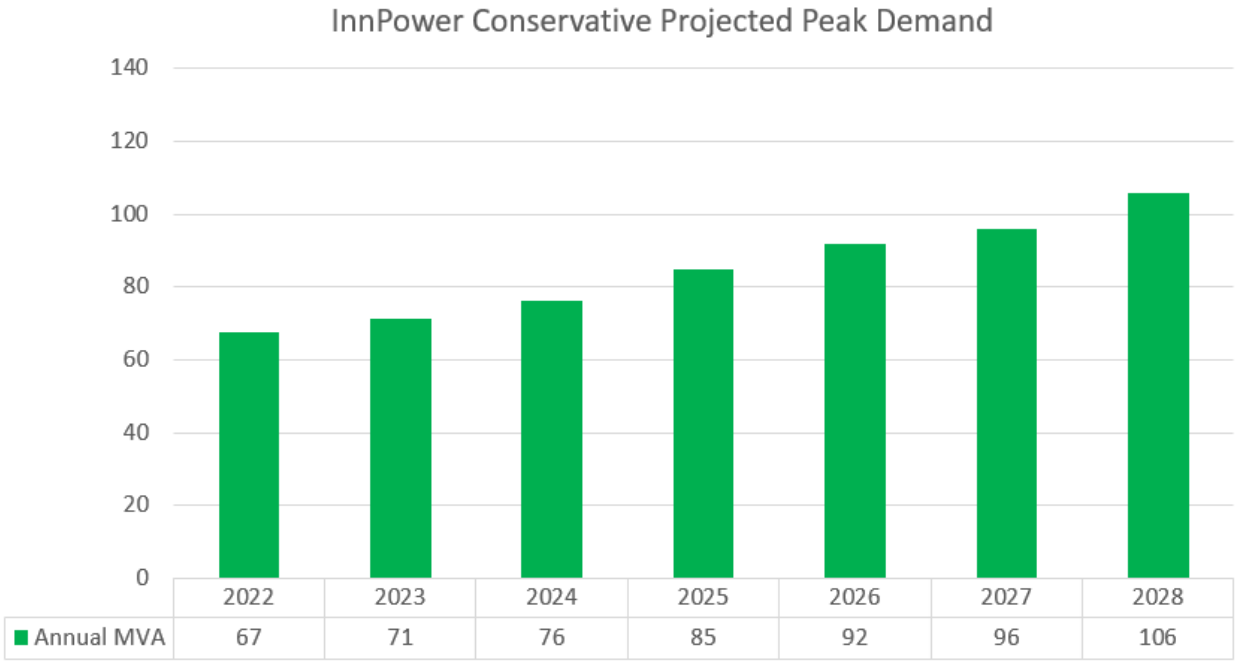


Figure 5.3-5: InnPower Conservative Projected Peak Demand

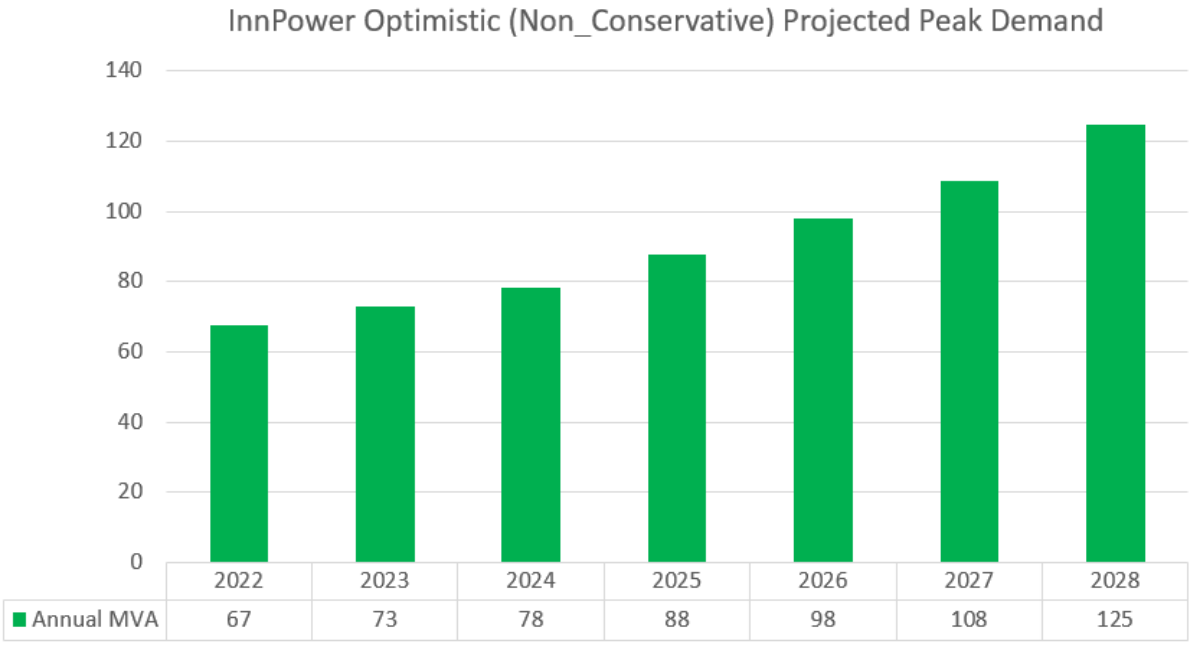


Figure 5.3-6: InnPower Optimistic Projected Peak Demand

Table 5.3-5 indicates the efficiency of the kilowatt-hour purchased by InnPower and delivered. Historical losses as a percentage of purchased energy have been above 5% except for in the year 2019. InnPower is currently undertaking a line loss study to better understand and identify the root causes of the elevated losses so that solutions can be developed to minimize losses and improve system efficiency going forward.

Table 5.3-5: Efficiency of kWh Purchased by InnPower

Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2017	242,651,316	256,769,435	5.5 %
2018	263,499,386	278,813,236	5.5 %
2019	270,098,352	280,581,537	3.7 %
2020	275,892,822	291,404,252	5.3 %
2021	278,373,132	295,240,254	5.7 %
2022	283,532,336	299,934,504	5.5%

Similar to the forecast customer and system peak trends, the total annual energy delivered is expected to continue growing over the forecast period, as shown in Figure 5.3-7. By the year 2028, InnPower expects its annual kWh of energy delivered to be approximately 34% higher relative to the total kWh of energy delivered in 2022.

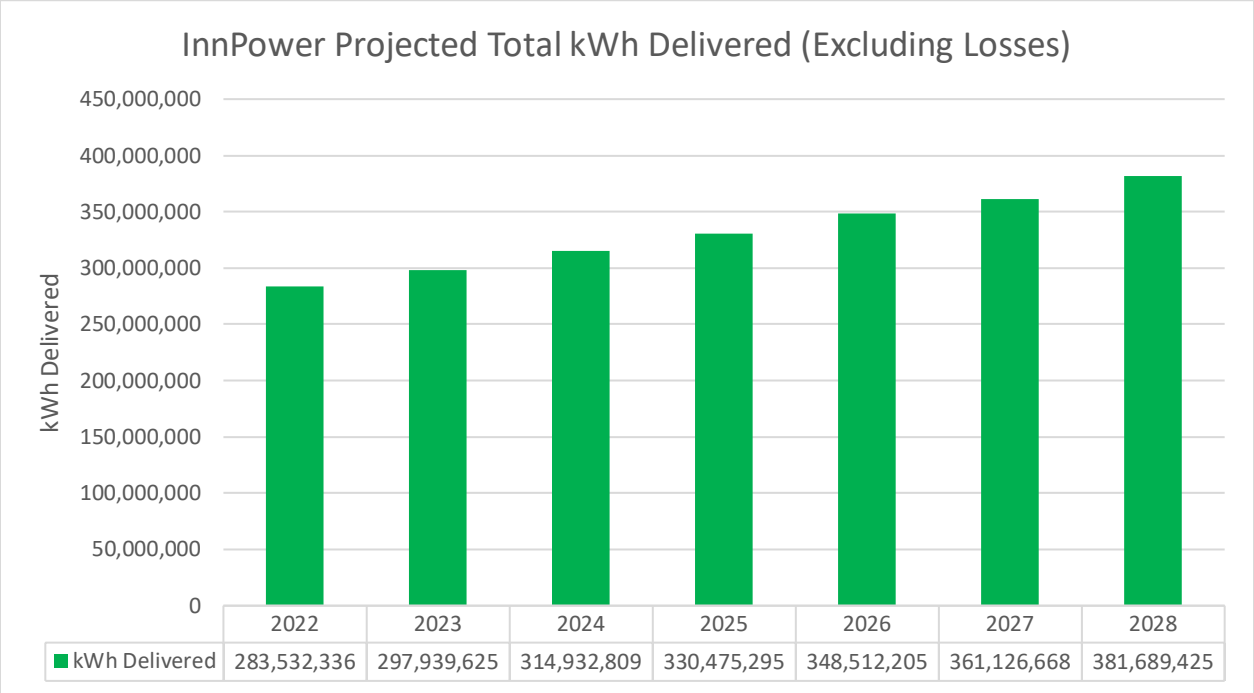


Figure 5.3-7: InnPower Projected Total kWh Delivered (Excluding Losses)

5.3.2.1.4 Summary of System Configuration

As of December 2022, InnPower owns 864 km of primary conductors, of which 671 km is OH primary conductor and 193 km is UG primary cable. InnPower operates using primary voltage levels of 8.32/4.80 kV and 27.6/16.0 kV for its distribution feeders, and 44 kV for its sub-transmission supply feeders. The number of circuits at each voltage level as well as the associated conductor length are summarized in Table 5.3-6.

Table 5.3-6: Summary of System Configuration

Voltage Level	Underground Cable Length (km)	Overhead Conductor Length (km)	Total Conductor Length (km)
8.32/4.80 kV	70.93	365.40	436.33
27.6/16.0 kV	120.23	171.02	291.25
44 kV	1.44	135.04	136.48
Total	**192.60**	**671.46**	**864.06**

InnPower owns ten DS cumulatively rated for 97.5 MVA. Table 5.3-7 lists the rated nominal capacity of each substation, in MVA.

Table 5.3-7: Rated Capacity of Distribution Substations

Substation	Output Voltage (kV)	Nominal Capacity (MVA)
Belle Ewart DS	27.6	10
Big Bay Point DS	27.6	10
Bob Deugo DS	27.6	10
Brian Wilson DS	27.6	20
Cedar Point DS	8.32	12.5
Innisfil DS	8.32	7.5
Lefroy DS	8.32	5
Leonard's Beach DS	8.32	7.5
Sandy Cove DS	8.32	10
Stroud DS	8.32	5
Total Nominal Capacity (MVA)		**97.5**

Two DS within InnPower's service territory are owned by HONI, but supply power through four feeders to InnPower's customers. These are the Thornton DS (Feeders F1 and F2) and the Cookstown West DS (Feeders F2 and F4).

5.3.2.2 Asset Information

A distributor should provide asset information (e.g.: asset capacity and utilization; asset condition; asset failures/performance; asset risks; and asset demographics), by major asset type, that may help

explain the specific need for the capital expenditures and demonstrate that a distributor has considered all economic alternatives.

5.3.2.2.1 Asset Capacity and Utilization

The system utilization relative to planning criteria is presented below for the future 230kV system, 44kV system, substation transformers, and distribution feeders.

230kV System Utilization

To address the load growth in Innisfil and South Barrie area, the first InnPower TS is planned to be energized near the end of the forecast period, either in the year 2027/2028 or potentially beyond (i.e.: InnPower is monitoring load behavior and will defer the need for this project as much as possible). The following information assumes energization in the year 2028. This station will consist of two 230/27.6kV, 50/67/83MVA transformers, and eight outgoing feeders.

Table 5.3-8: Transformer Station 230/27.6 kV - Summer & Winter Peak Load Forecast

Transformer	Nominal MVA	Peak Load (MVA)											
		2023		2024		2025		2026		2027		2028	
		S	W	S	W	S	W	S	W	S	W	S	W
New TS T1	50/67/83	---	---	---	---	---	---	---	---	---	---	7.03	6.40
New TS T2	50/67/83	---	---	---	---	---	---	---	---	---	---	1.98	1.80

Table 5.3-9: Transformer Station 230/27.6 kV Feeders – Summer & Winter Peak Load Forecast

Feeder	Recloser Setting (A)	Peak Load (A)											
		2023		2024		2025		2026		2027		2028	
		S	W	S	W	S	W	S	W	S	W	S	W
New TS T1 F1	400	---	---	---	---	---	---	---	---	---	---	30.66	27.90
New TS T1 F3	400	---	---	---	---	---	---	---	---	---	---	29.36	26.72
New TS T1 F5	400	---	---	---	---	---	---	---	---	---	---	33.15	30.17
New TS T1 F7	400	---	---	---	---	---	---	---	---	---	---	53.95	49.10
New TS T2 F2	400	---	---	---	---	---	---	---	---	---	---	17.88	16.18
New TS T2 F4	400	---	---	---	---	---	---	---	---	---	---	00.00	00.00
New TS T2 F6	400	---	---	---	---	---	---	---	---	---	---	00.00	00.00
New TS T2 F8	400	---	---	---	---	---	---	---	---	---	---	23.67	21.54

44 kV System Utilization

There are five 44 kV feeders within InnPower's service territory. Another 44 kV feeder will be added by 2024 increasing the total number to six. Nominally, a 44kV feeder on InnPower's system is rated for 660 A of current, but the assigned capacity from Hydro One is different and listed in Table 5.3-10.

Table 5.3-10 illustrates the summer ("S") and winter ("W") peak load forecasts for each 44kV feeder for the years 2023 to 2028. Feeders which exceed 80% of their assigned capacity are highlighted in yellow.

Table 5.3-10: 44 kV Feeder Summer and Winter Peak Load Forecast

44 kV Feeder	Feeder Assigned Capacity (A)	Peak Load (A)											
		2023		2024		2025		2026		2027		2028	
		S	W	S	W	S	W	S	W	S	W	S	W
9M1 & 9M2*	433	493.2	439.0	469.9	418.2	465.8	414.6	478.5	425.9	490.6	436.6	512.4	456.0
9M4	223	154.7	137.7	171.3	152.5	190.3	169.4	202.9	180.6	218.3	194.3	226.8	201.8
9M6	78	40.6	36.9	42.2	38.4	42.2	38.4	42.2	38.4	42.2	38.4	42.2	38.4
13M3 & 13M4*	660	266.7	240.0	345.6	311.0	450.7	405.6	560.6	504.5	672.1	604.9	737.5	663.8

**Two feeders from the same bus at the transformer station*

System planning evaluations over the forecast period for the numbers highlighted in yellow in the table above are noted below:

- 9M1 and 9M2 are being monitored through Hydro One and also InnPower to possibly transfer any future loads to the new Barrie 13M3 and 13M4 feeders as well as InnPower's new TS.
- 9M4 feeder rating is 345A nominal and InnPower is monitoring loads to make sure it does not exceed the maximum assigned capacity.
- InnPower is planning to utilize the maximum nominal feeder ratings on 13M3 and 13M4. The new TS will be an alternative to transfer additional loads beyond 2028.

Distribution Station Transformer Utilization

Table 5.3-11 presents the summer and winter peak load forecast for each DS for the years 2023 to 2028. DESN station transformers are assessed independently of each other. Transformers that exceed 80% of their nominal load are highlighted in yellow and those that exceed 100% of their nominal load are highlighted in red.

Table 5.3-11: Distribution Station Summer and Winter Peak Load Forecast

Transformer	Nominal MVA	Peak Load (MVA)											
		2023		2024		2025		2026		2027		2028	
		S	W	S	W	S	W	S	W	S	W	S	W
Belle Ewart T1[2]	10/13.3/16.6	9.75	8.69	9.91	8.83	10.01	8.92	10.11	9.01	10.21	9.10	10.31	9.19
Belle Ewart T2[1]	30	---	---	---	---	---	---	1.20	1.07	2.20	1.96	3.72	3.31
Big Bay Point T1	10/12/16	4.40	3.96	5.00	4.50	5.53	4.98	6.00	5.40	6.50	5.85	7.50	6.75
Big Bay Point T2[1]	16/20/24	2.90	2.61	2.96	2.66	5.26	4.73	6.93	6.24	10.43	9.39	10.25	9.23
Bob Deugo T1	10	4.43	3.95	4.50	4.01	4.98	4.44	5.27	4.70	5.35	4.77	6.55	5.84
Bob Deugo T2[1]	16/20/24	---	---	1.99	1.79	3.66	3.29	7.00	6.30	9.11	8.20	8.25	7.43
Brian Wilson T1	10	5.93	5.28	6.42	5.72	7.05	6.28	7.80	6.95	8.11	7.23	8.34	7.43
Brian Wilson T2[2]	10/13.3/16.6	8.69	7.74	9.82	8.75	11.89	10.59	12.48	11.12	13.55	12.07	14.02	12.49
Cedar Point T1	5	4.65	4.14	4.65	4.14	4.65	4.14	4.65	4.14	4.65	4.14	4.65	4.14

Transformer	Nominal MVA	Peak Load (MVA)											
		2023		2024		2025		2026		2027		2028	
		S	W	S	W	S	W	S	W	S	W	S	W
Cedar Point T2	7.5/10/12.5	0.83	0.74	1.23	1.10	1.26	1.12	1.65	1.47	2.07	1.84	2.16	1.92
CooksTown West	7	3.09	2.81	3.21	2.92	3.21	2.92	3.21	2.92	3.21	2.92	3.21	2.92
Innisfil	7.5/9.9/12.5	5.58	4.97	5.58	4.97	5.58	4.97	5.58	4.97	5.58	4.97	5.58	4.97
Lefroy	5	2.86	2.55	2.90	2.58	2.91	2.59	3.00	2.67	3.20	2.85	3.25	2.90
Leonard's Beach	7.5/10/12.5	5.24	4.67	5.29	4.72	5.35	4.76	5.45	4.86	5.65	5.03	5.99	5.34
Sandy Cove T1	5	2.98	2.68	2.98	2.68	2.98	2.68	2.98	2.68	2.98	2.68	2.98	2.68
Sandy Cove T2	5	0.74	0.67	0.75	0.68	0.81	0.73	0.90	0.81	1.11	1.00	1.56	1.40
Stroud	5	2.37	2.13	2.37	2.13	2.37	2.13	2.37	2.13	2.37	2.13	2.37	2.13
Thornton	5	2.00	1.78	2.00	1.78	2.00	1.78	2.00	1.78	2.00	1.78	2.00	1.78

[1] These transformers are forecasted projects that do not exist presently. Big Bay Point T2, Bob Duego T2, and Belle Ewart T2 are planned to be energized in 2023, 2024, and 2026 respectively.

[2] Considering the load growth in areas covered by Brian Wilson T2 and Belle Ewart T1, additional transformer capacity is required in both DS. InnPower is actively working with a group of developers to upgrade the Brian Wilson T2 and Belle Ewart T1 transformers, which will be 100% recoverable.

Distribution Feeder Utilization

Table 5.3-12 presents the summer and winter peak load forecast for each distribution feeder for the years 2023 to 2028. Feeders with loads exceeding 50% of the recloser setting are highlighted in yellow.

Table 5.3-12: Distribution Feeder Summer and Winter Peak Load Forecast

Feeder[1]	Recloser Setting (A)	Peak Load (A)											
		2023		2024		2025		2026		2027		2028	
		S	W	S	W	S	W	S	W	S	W	S	W
BEF1	350	29.5	26.28	32.84	29.26	34.92	31.11	37.01	32.97	39.12	34.86	41.26	36.76
BEF2	350	174.46	155.44	174.46	155.44	174.46	155.44	174.46	155.44	174.46	155.44	174.46	155.44
BEF3	350							9.35	8.33	9.35	8.33	9.35	8.33
BEF4	350							15.75	14.03	36.67	32.67	68.46	61.00
BEF5	350							0.00	0.00	0.00	0.00	0.00	0.00
BBPF1	350	31.86	28.68	42.53	38.28	51.96	46.76	60.32	54.28	60.32	54.28	79.18	71.26
BBPF2	350	60.18	54.16	62.06	55.85	63.72	57.35	65.19	58.68	75.65	68.09	77.71	69.94
BBPF3	350	25.60	23.04	26.26	23.63	50.36	45.32	68.74	61.87	98.01	88.21	95.72	86.15
BBPF4	350	35.07	31.56	35.66	32.09	59.67	53.71	76.22	68.60	120.17	108.15	118.69	106.82
BDF1	300	35.76	31.86	40.11	35.74	50.15	44.69	56.22	50.09	56.22	50.09	67.08	60.41

Feeder[1]	Recloser Setting (A)	Peak Load (A)											
		2023		2024		2025		2026		2027		2028	
		S	W	S	W	S	W	S	W	S	W	S	W
BDF2	300	56.91	50.71	54.02	48.13	54.02	48.13	54.02	48.13	55.69	49.62	69.42	61.86
BDF3	350			17.12	15.41	36.93	33.23	69.13	62.22	76.93	69.24	68.26	61.43
BDF4	350			24.51	22.06	39.64	35.67	77.30	69.57	113.64	102.28	104.32	93.88
BWF1	250	106.58	94.96	109.45	97.52	112.43	100.18	114.04	101.61	114.04	101.61	114.04	101.61
BWF2	200	17.46	15.56	24.85	22.14	35.04	31.22	49.12	43.77	55.65	49.58	60.42	53.83
BWF3	250	161.68	144.06	185.32	165.12	228.62	203.70	240.97	214.70	263.35	234.64	273.18	243.40
BWF4	200	20.10	17.91	20.10	17.91	20.10	17.91	20.10	17.91	20.10	17.91	20.10	17.91
CPF1	280	135.32	120.57	135.32	120.57	135.32	120.57	135.32	120.57	135.32	120.57	135.32	120.57
CPF2	340	187.36	166.94	187.36	166.94	187.36	166.94	187.36	166.94	187.36	166.94	187.36	166.94
CPF3	440	57.60	51.32	85.35	76.05	87.44	77.90	114.50	102.02	143.64	127.99	149.89	133.55
CWF2	280	91.60	83.35	95.25	86.68	95.25	86.68	95.25	86.68	95.25	86.68	95.25	86.68
CWF4	280	122.83	111.77	127.50	116.02	127.50	116.02	127.50	116.02	127.50	116.02	127.50	116.02
INNF1	340	124.91	111.29	124.91	111.29	124.91	111.29	124.91	111.29	124.91	111.29	124.91	111.29
INNF2	340	116.58	103.87	116.58	103.87	116.58	103.87	116.58	103.87	116.58	103.87	116.58	103.87
INNF3	340	145.73	129.84	145.73	129.84	145.73	129.84	145.73	129.84	145.73	129.84	145.73	129.84
LEF1	280	142.71	127.16	145.49	129.63	146.18	130.25	147.27	131.22	147.27	131.22	147.27	131.22
LEF2	280	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LEF3	350	55.75	49.67	55.75	49.67	55.75	49.67	60.72	54.10	74.78	66.63	78.25	69.72
LBF1	280	68.65	61.17	68.65	61.17	68.65	61.17	68.65	61.17	68.65	61.17	68.65	61.17
LBF2	340	4.99	4.45	8.63	7.69	12.30	10.96	19.43	17.31	33.31	29.68	56.90	50.70
LBF3	340	290.06	258.45	290.06	258.45	290.06	258.45	290.06	258.45	290.06	258.45	290.06	258.45
SCF1	340	111.72	100.55	111.72	100.55	111.72	100.55	111.72	100.55	111.72	100.55	111.72	100.55
SCF2	340	51.35	46.22	52.04	46.84	56.21	50.29	62.45	56.21	77.03	69.32	108.25	97.43
SCF3	340	95.07	85.56	95.07	85.56	95.07	85.56	95.07	85.56	95.07	85.56	95.07	85.56
STF1	280	81.88	73.70	81.88	73.70	81.88	73.70	81.88	73.70	81.88	73.70	81.88	73.70
STF2	280	10.41	9.37	10.41	9.37	10.41	9.37	10.41	9.37	10.41	9.37	10.41	9.37
STF3	280	72.17	64.95	72.17	64.95	72.17	64.95	72.17	64.95	72.17	64.95	72.17	64.95
THF1	225	58.98	53.09	58.98	53.09	58.98	53.09	58.98	53.09	58.98	53.09	58.98	53.09
THF2	225	79.80	71.82	79.80	71.82	79.80	71.82	79.80	71.82	79.80	71.82	79.80	71.82

[1] Feeder names are defined as: BEF: Belle Ewart Feeder; BBPF: Big Bay Point Feeder; BDF: Bob Duego Feeder; BWF: Brian Wilson Feeder; CPF: Cedar Point Feeder; CWF: CooksTown West Feeder; INNF: Innisfil Feeder; LEF: Lefroy Feeder; LBF: Leonard's Beach Feeder; SCF: Sandy Cove Feeder; STF: Stroud Feeder; THF: Thornton Feeder

System planning evaluations over the forecast period for the numbers highlighted in yellow in the table above are noted below:

- InnPower is planning to transfer the 8.32kV loads to 27.6kV after the completion of Big Bay Point DS T2.
- This can reduce the loads from LB F3.
- Also, this load can be split between LB F2 and Sandy Cove F2 during emergency situations.

5.3.2.2.2 Asset Condition and Age Demographics

The ACA study was carried out by METSCO for InnPower to establish the health and condition of station and distribution assets in-service. The ACA is based on data compiled to the end of October 2021. Figure 5.3-8 and Figure 5.3-9 present the summary Health Index (HI) results of the ACA for distribution assets and station assets, respectively.

The HI is not calculated for any distribution asset with a Data Availability Indicator (DAI) less than 70% (i.e.: less than 70% of the condition parameters—by weight—are available for that asset) or less than 60% for station assets. The HI results for assets with a known HI were divided into ten-year bands and extrapolated to the unknown set within those bands. The age demographics and condition breakdown for each asset class are further detailed below. The complete ACA study can be found in Appendix J of the DSP.

As referenced in *s*ection 5.3.1.3, InnPower uses the outputs of the ACA as a key input into its capital planning process. Where InnPower has calculated valid HIs with the required data availability, it uses this information to inform which assets to potentially replace and/or repair. Where data availability is below the DAI threshold and InnPower has identified the asset(s) that may need attention, InnPower performs further assessments, gathering further data before deciding if the asset(s) should be replaced and/or repaired.

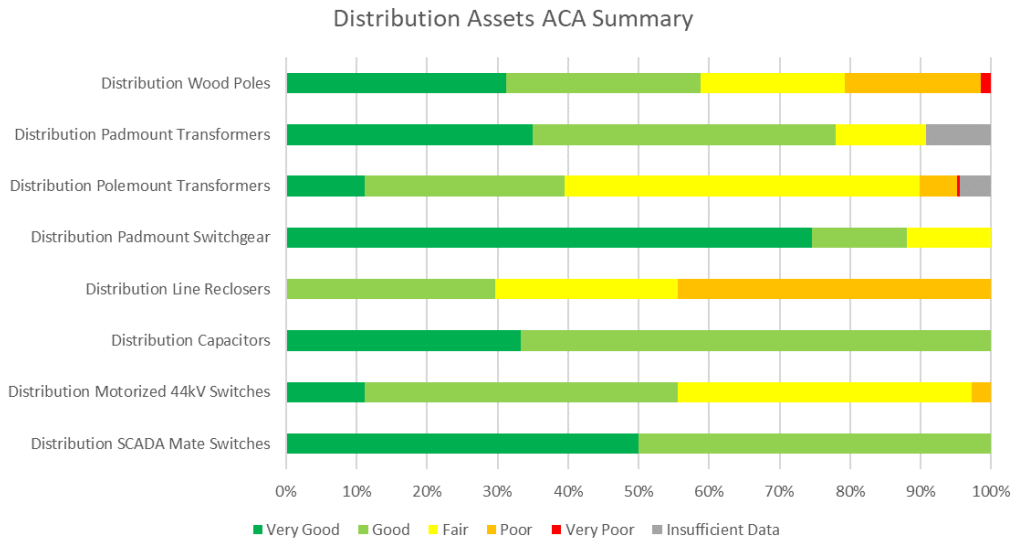


Figure 5.3-8: Distribution Assets ACA Summary

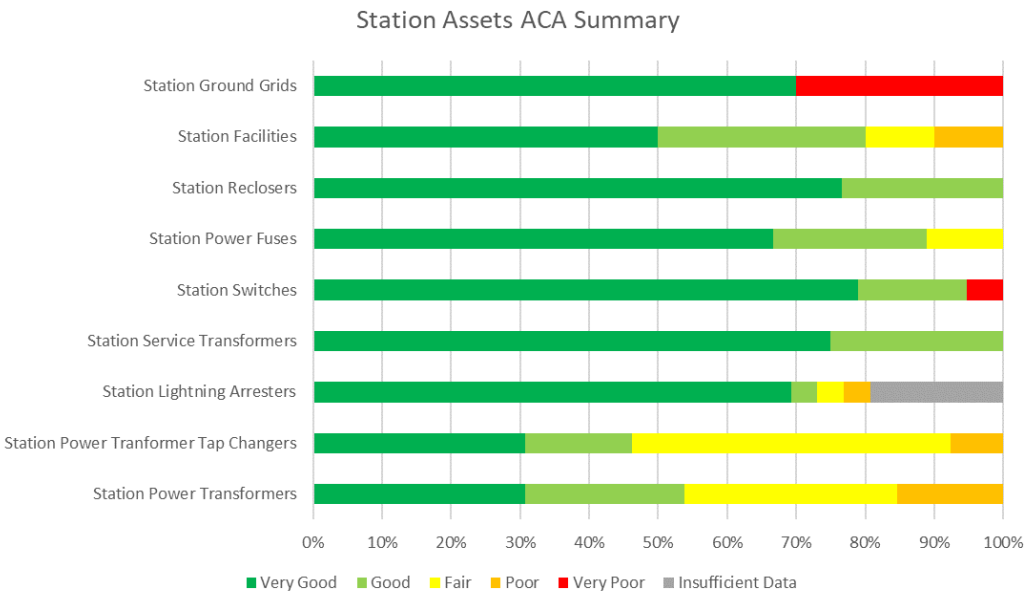


Figure 5.3-9: Station Assets ACA Summary

Figure 5.3-8 and Figure 5.3-9 above indicate that the majority of InnPower's system is in a generally healthy condition, with few assets in poor or very poor condition, indicating an increased probability of failure. Distribution assets are also shown to have a higher ratio of assets in fair condition.

Station Power Transformers

InnPower currently owns 13 power transformers within its distribution system. The age demographics for this asset class are presented in Figure 5.3-10.

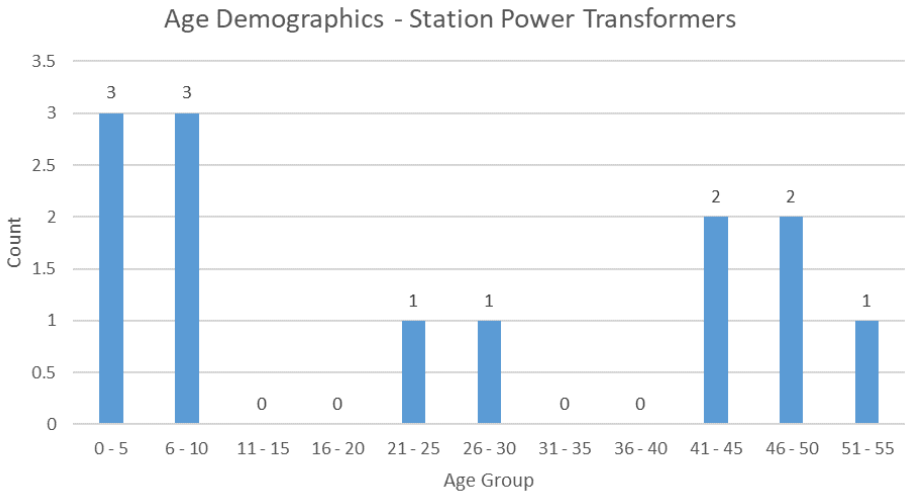


Figure 5.3-10: Power Transformer Age Demographics

Inspections, electrical tests, chemical tests, and loading history were used to calculate the HI. Four of the transformers analyzed fell in the fair condition category, with another two categorized as poor,

which may be candidates for upcoming corrective action. The HI distribution for power transformers can be seen below in Figure 5.3-11.

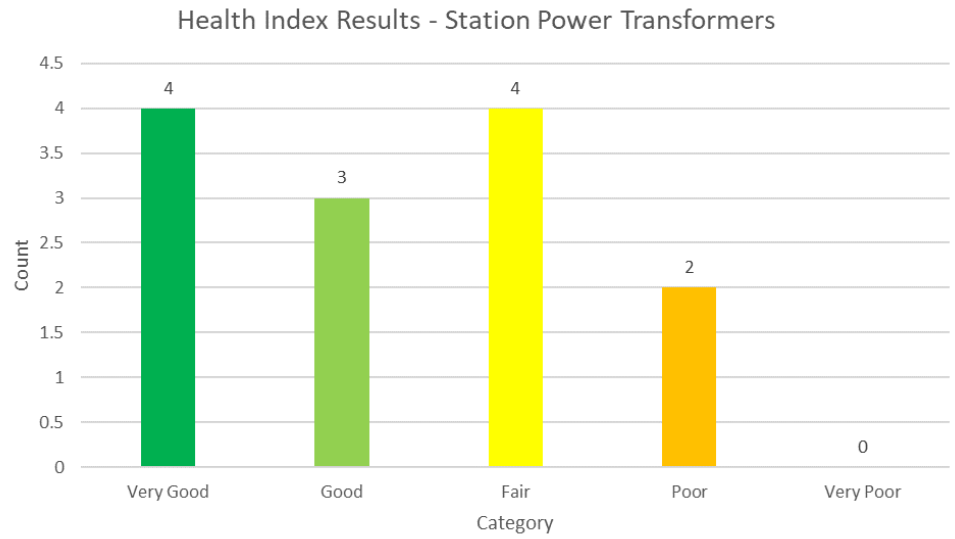


Figure 5.3-11: Station Power Transformers ACA Results

Station Power Transformer Tap Changers

Thirteen power transformer tap changers are in use in InnPower's service area. The age demographics for these units are presented in Figure 5.3-12.

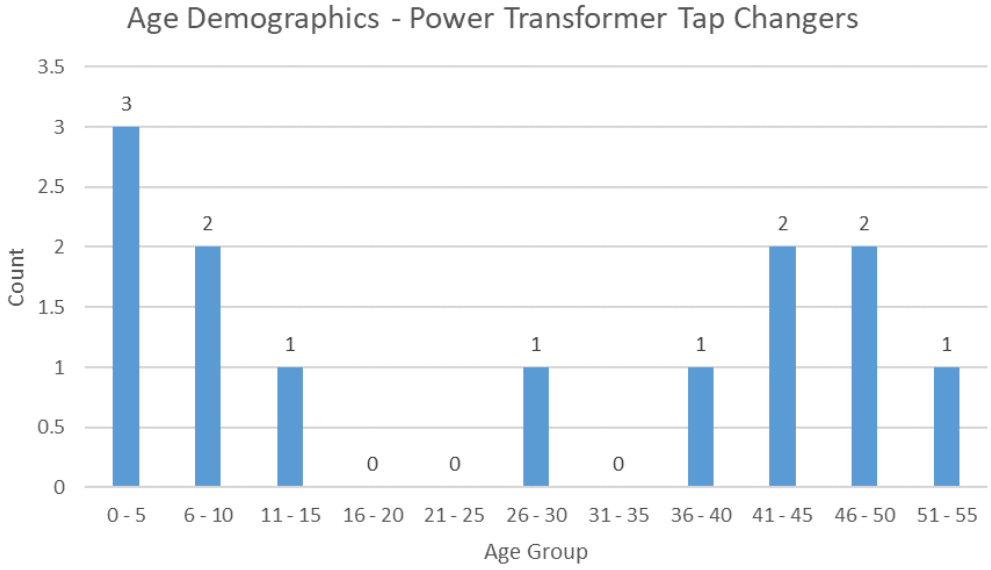


Figure 5.3-12: Power Transformer Age Demographics

Of these 13 units, a large proportion falls into the fair or poor categories, which indicate an increased risk of failure or further degradation and should be targeted for refurbishment or replacement. The full HI distribution can be seen in Figure 5.3-13.

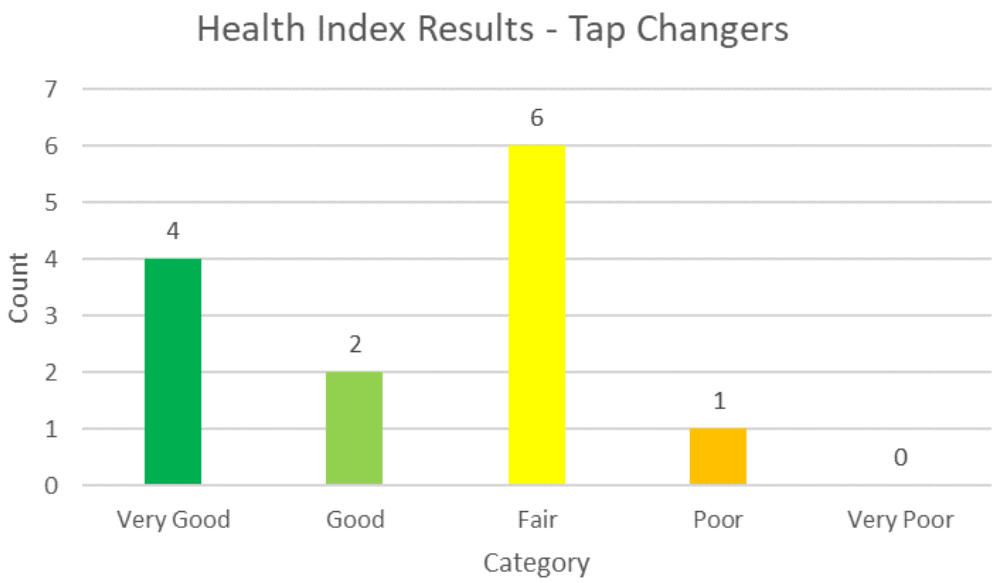


Figure 5.3-13: Power Transformer Tap Changer ACA Results

Station Switches

A total of 38 station switches are in service currently, with 21 station load break switches, 14 station switchgears, and three 44kV transrupters. InnPower does not currently have records of age data for the Station Switches or Switchgear Switches sub-classes, but the age demographics for 44kV transrupters are presented in Figure 5.3-14.

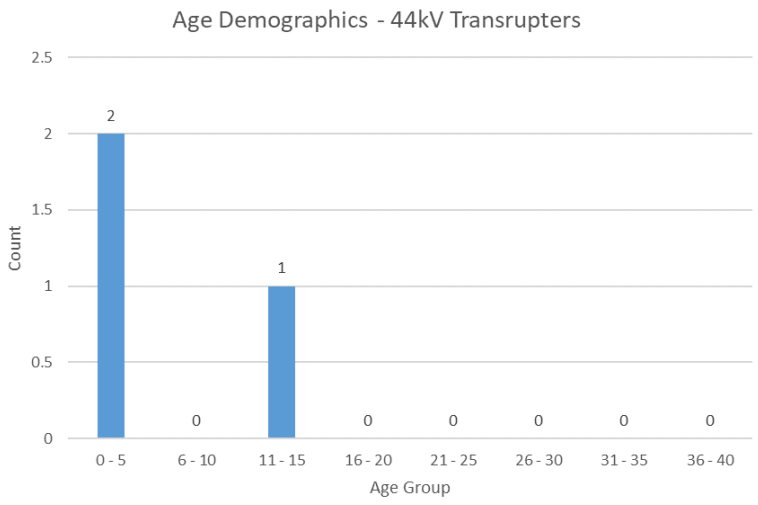


Figure 5.3-14: 44kV Transrupter Age Demographics

Almost all of this service class is in the good or very good category, except for two load break switches. The full distribution of results can be seen in Figure 5.3-15.

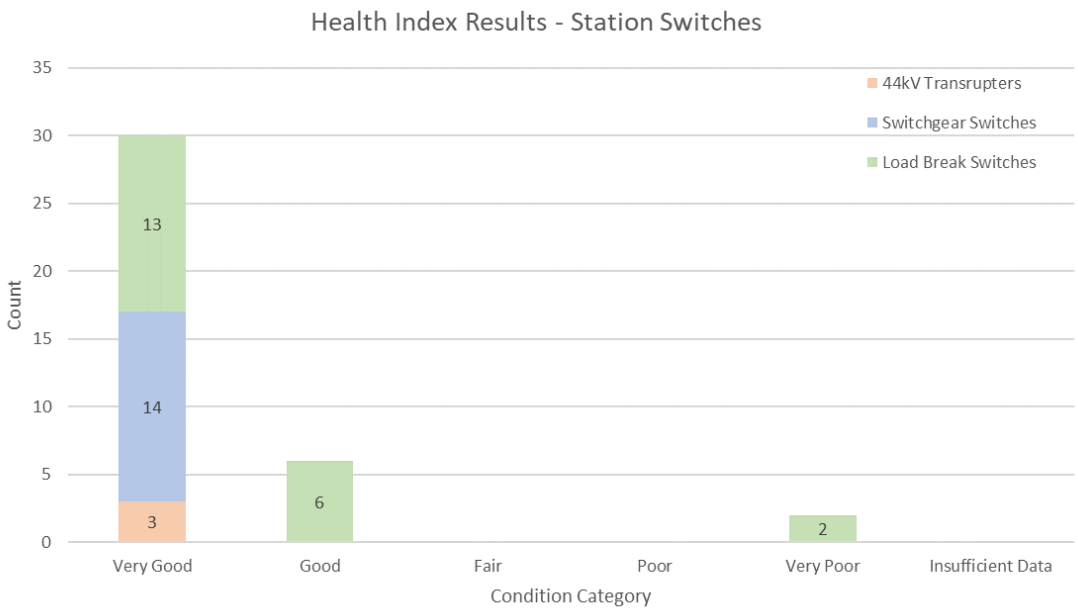


Figure 5.3-15: Station Switches ACA Results

Station Reclosers

InnPower owns and operates 30 station reclosers at substations. The age demographics for these units are shown in Figure 5.3-16.

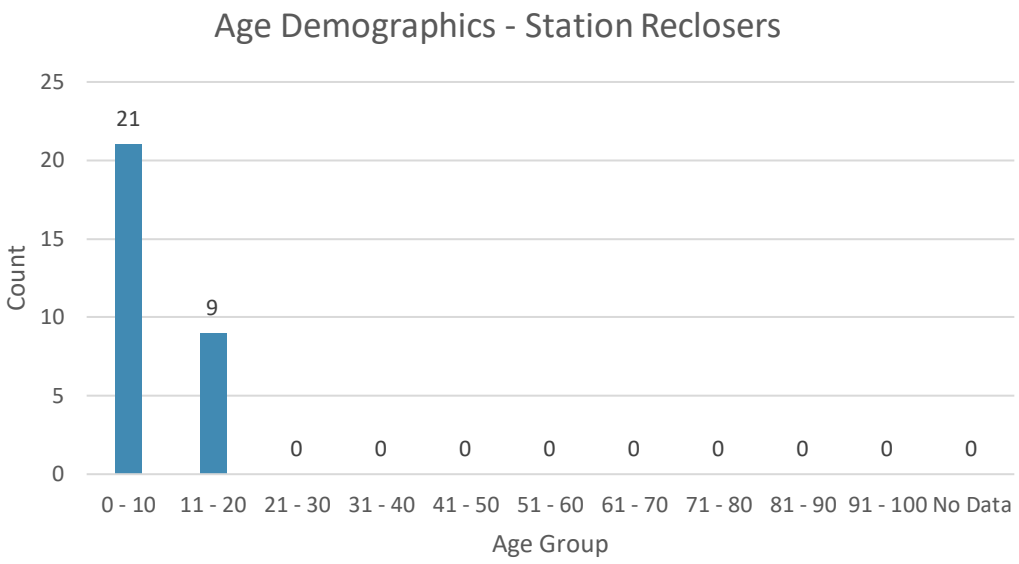


Figure 5.3-16: Station Recloser Age Demographics

All of the station reclosers are graded as either very good or good. The full distribution of results can be seen in Figure 5.3-17.

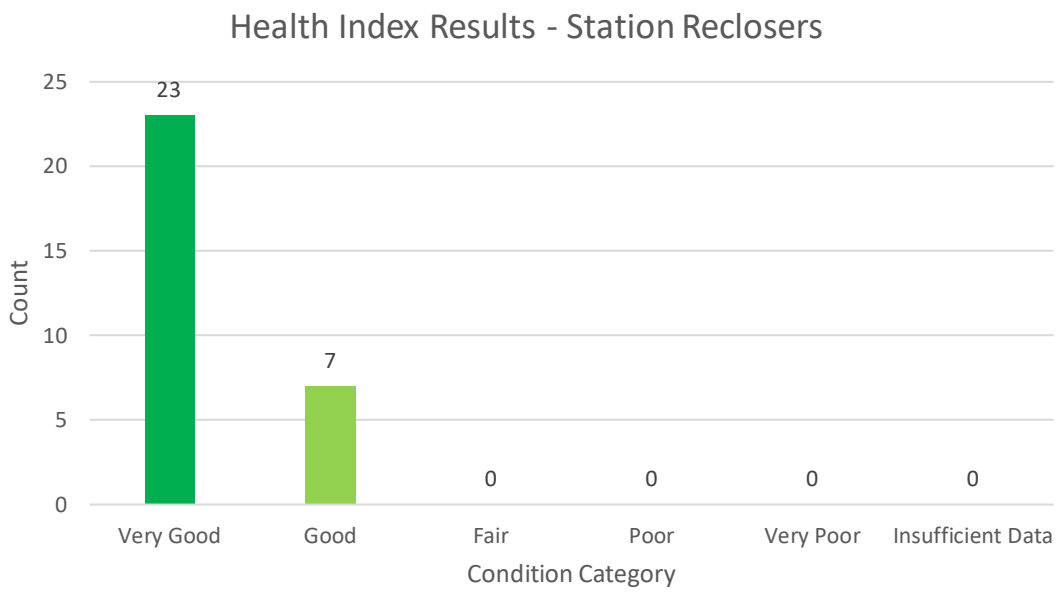


Figure 5.3-17: Station Recloser ACA Results

Station Service Transformers

There are currently 12 station service transformers deployed in InnPower's station. The age demographics for this asset class are presented in Figure 5.3-18.

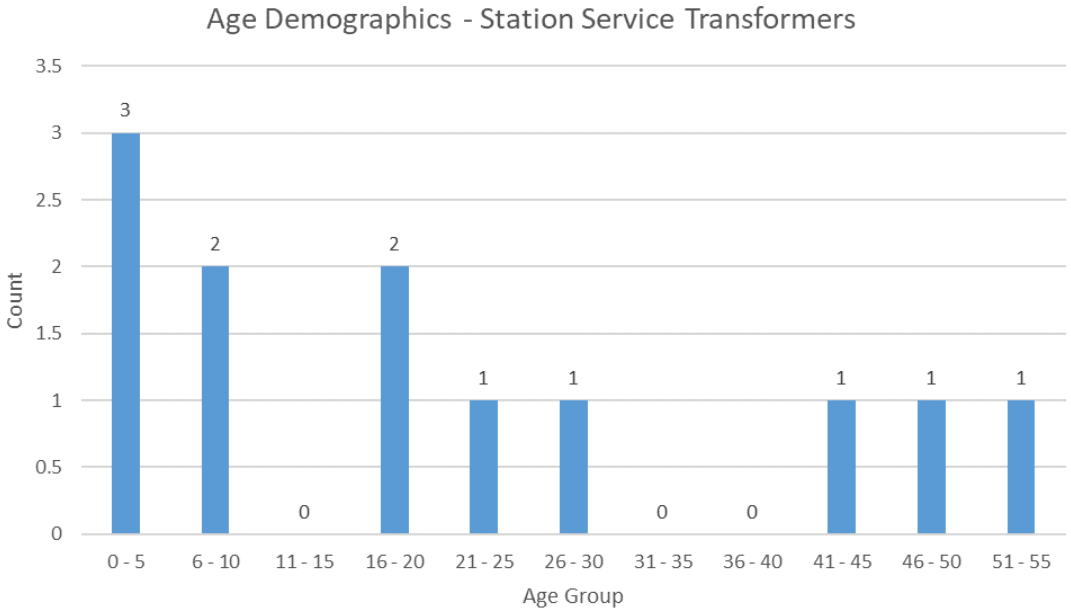


Figure 5.3-18: Station Service Transformer Age Demographics

As shown in Figure 5.3-19, the 12 transformers are categorized as either good or very good, indicating a healthy asset class.

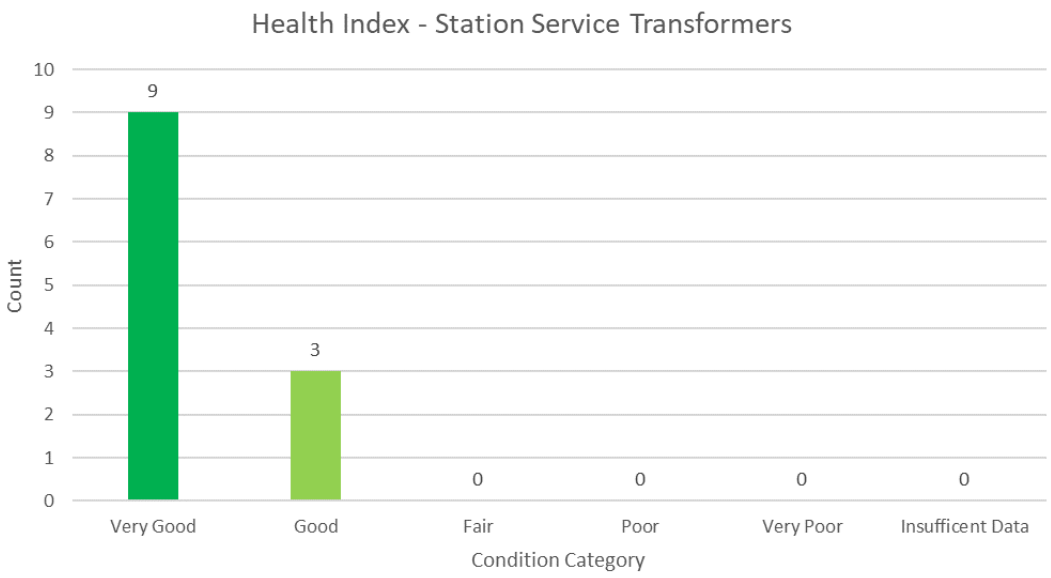


Figure 5.3-19: Station Service Transformer ACA Results

Station Lightning Arresters

InnPower currently owns two station lightning arresters per power transformer, for a total of 26. Age demographics are not available for this asset class as age data is not captured in any existing datasets. However, the HI results are presented in Figure 5.3-20 below. Of these, 18 are rated as very good, with one each of good, fair, poor, and very poor. The remaining five had insufficient data available to calculate an HI.

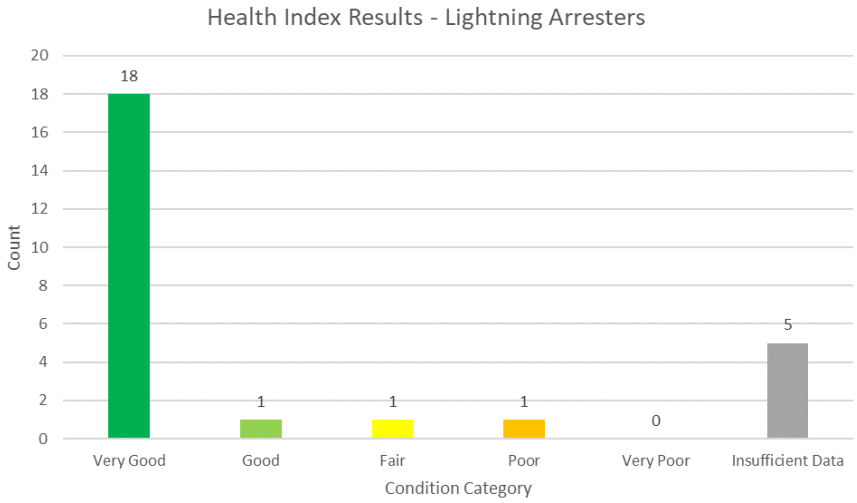


Figure 5.3-20: Station Lightning Arrester ACA Results

Station Power Fuses

A total of nine station power fuses are currently located at InnPower DS. There is no age data available for this asset class, however, the condition assessment results for this asset class are presented in

Figure 5.3-21. The asset class is overall in good condition, with 89% of the class in very good or good, with the remaining fuses in fair.

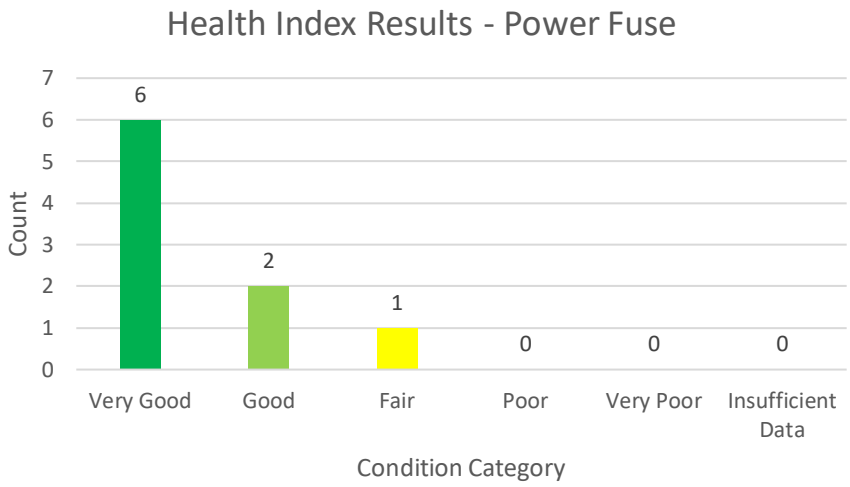


Figure 5.3-21: Station Power Fuse ACA Results

Station Ground Grids

A station ground grid provides a low resistance ground for system neutral to maintain grounding and maintain safe potential gradients inside the station yard. There was one ground grid per station assessed, for a total of ten. Given the nature of this asset class, age data was not available, however, the condition assessment results are presented in Figure 5.3-22. While the majority of the results are very good, three stations had ground grids that were evaluated as very poor. Since the completion of this ACA, the ground grids in very poor condition have been addressed.

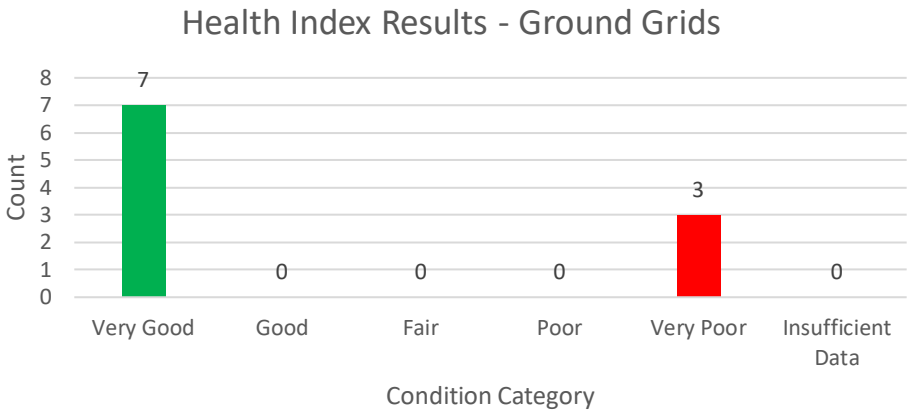


Figure 5.3-22: Station Ground Grid ACA Results

Station Facilities

Station facilities refer to some of the non-distribution assets at station sites, including the condition of the yard, fence, and structure. InnPower owns ten stations within its service territory. Given the nature

of this asset class, age data was not available; however, the condition assessment results are presented in Figure 5.3-23. Eight of the stations were graded as very good or good facilities, with one each in the fair and poor categories.

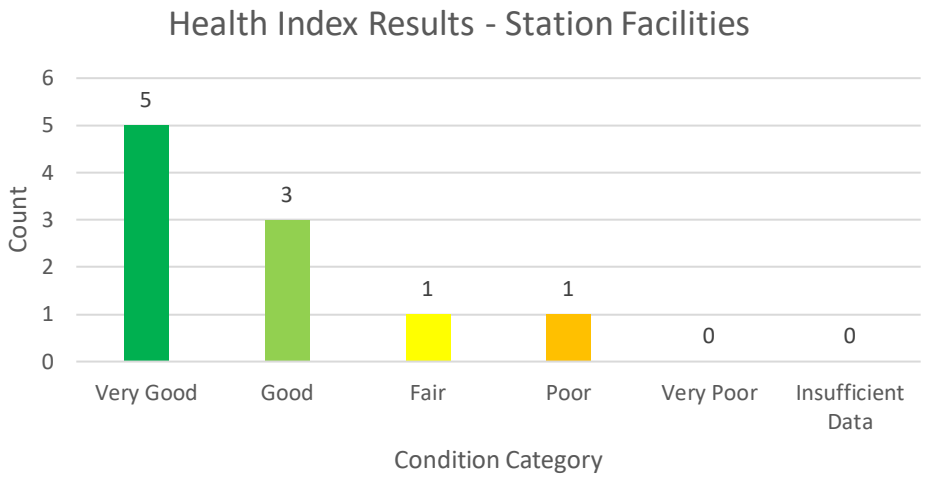


Figure 5.3-23: Station Facilities ACA Results

Poles

When the ACA was conducted, InnPower owned 10,043 wood poles within its service territory. Asset data was provided for a total of 7,339 wood poles. The age distribution for this class is presented below in Figure 5.3-24.

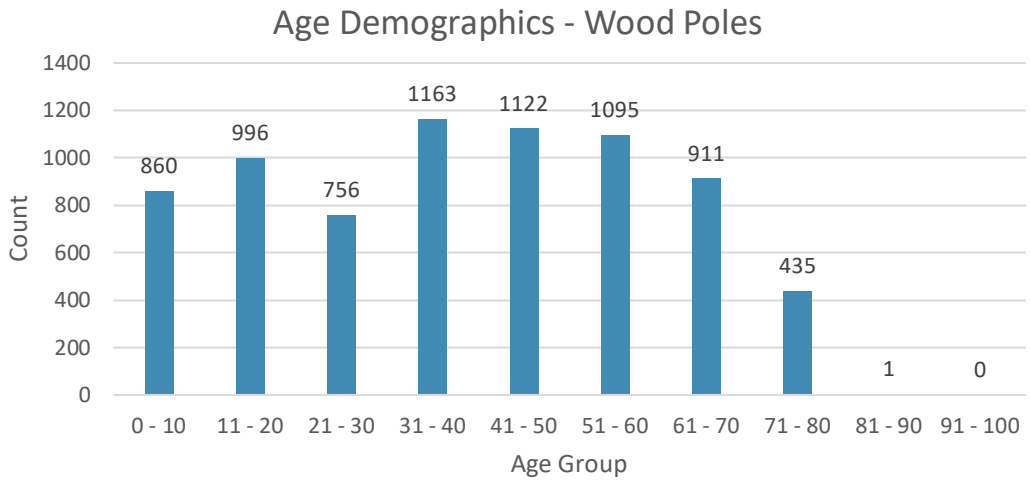


Figure 5.3-24: Wood Poles Age Distribution

Visual inspections and resistographs (i.e.: from Polux testing) of InnPower-owned poles are completed with internal resources, on a six-year cycle. The condition-based assessment allows InnPower to monitor and identify defects concerning the integrity of the pole or other issues concerning the condition of the pole, supports, and attachments including conductors, cross arms, guys, etc. Any defects are identified through inspections and tests and detailed further through commentary. The

extrapolated HI distribution for wood poles is presented in Figure 5.3-25. A significant proportion of poles are in poor condition, with 21% in either poor or very poor conditions, which may require short-term intervention through replacement. An additional 20% of poles are in the fair condition category and are at risk of degrading into poor or very poor conditions.

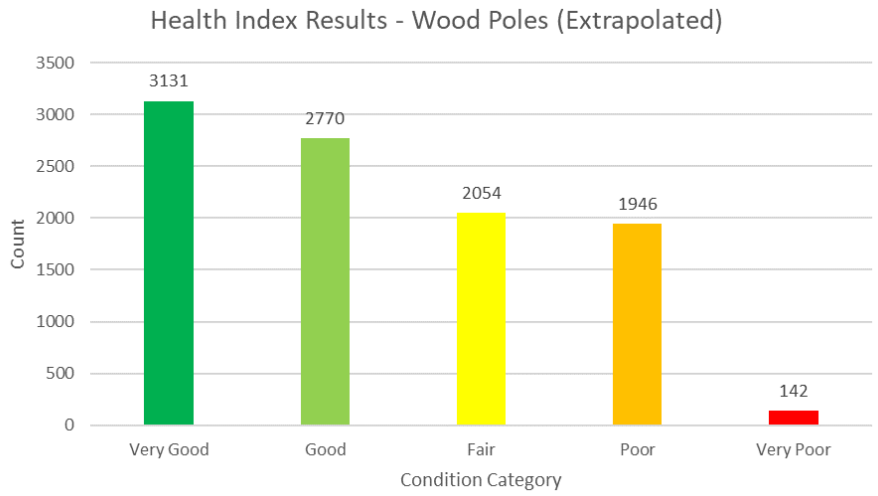


Figure 5.3-25: Wood Pole ACA Results - Extrapolated

Overhead Distribution (Pole-Mount) Transformers

When the ACA was conducted, InnPower owned a total of 2,177 pole-mount transformers within its service territory. Figure 5.3-26 below presents the age demographics for this asset class.

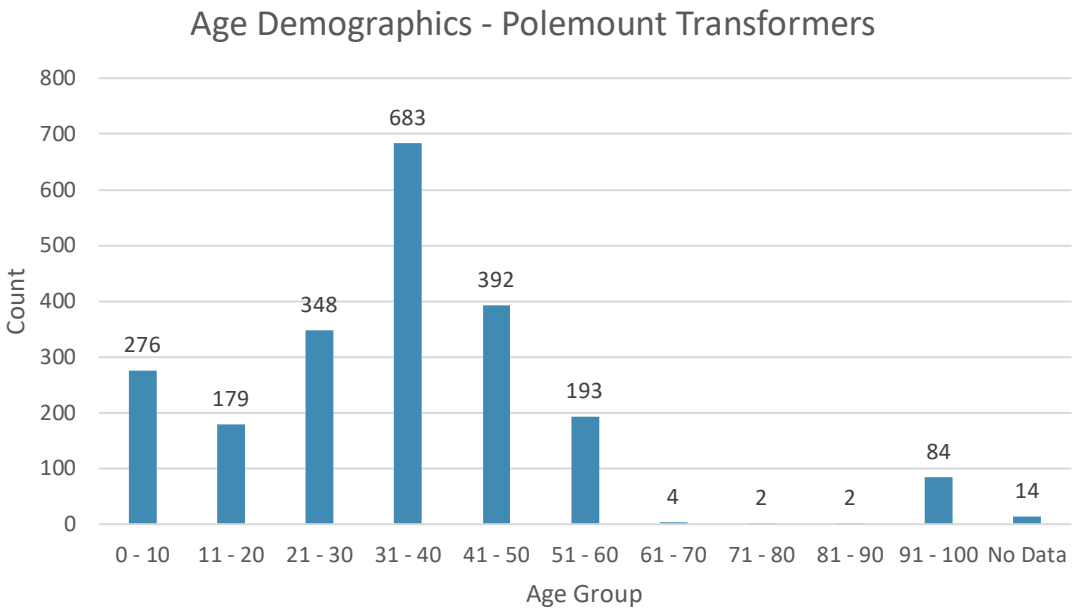


Figure 5.3-26: Distribution Pole Mount Transformer Age Distribution

The extrapolated HI results are presented below in Figure 5.3-27. Approximately half of the units fall under the fair condition, which may further degrade into poor or very poor and require asset intervention over the long term.

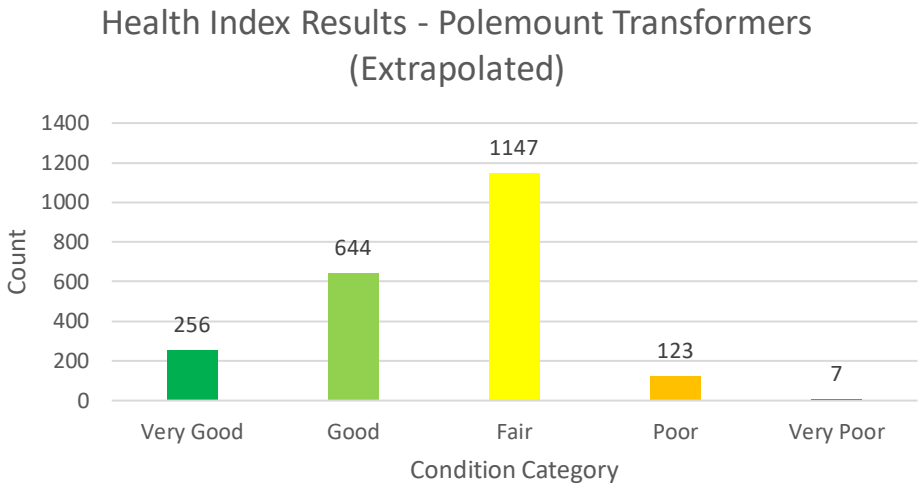


Figure 5.3-27: Polemount Transformer ACA Results: Extrapolated

Line Reclosers

InnPower owns 27 oil-only line recloser units within its service territory. The age demographics for this asset class are presented below in Figure 5.3-28.

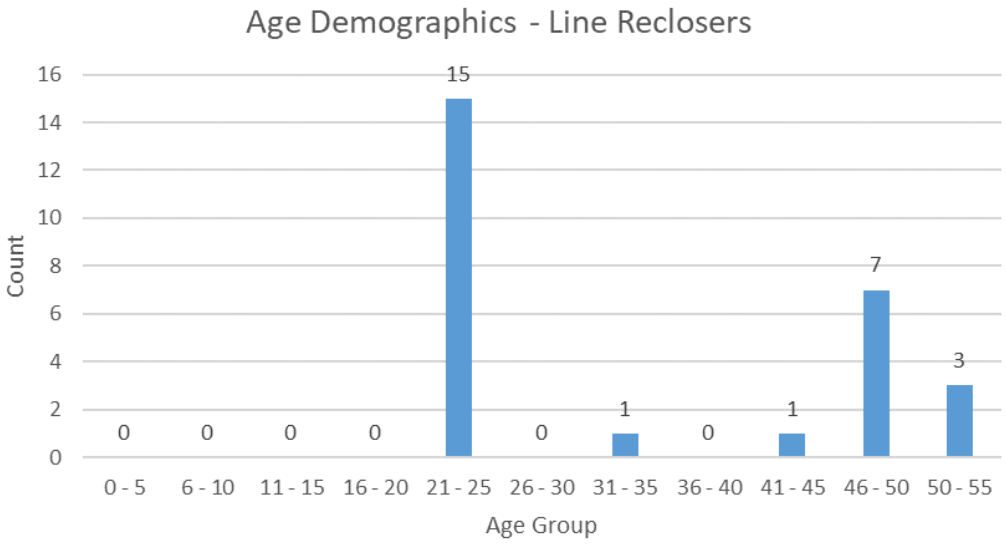


Figure 5.3-28: Line Reclosers Age Distribution

The HI distribution for in-service line reclosers are presented in Figure 5.3-29 and was calculated based on age, visual inspections conducted, and Infrared (IR) scanning results. Twelve of the

reclosers fall into the poor category, which may indicate an elevated risk of failure. An additional seven fall in the fair category, which may require intervention strategies to prevent further degradation to the poor or very poor category.



Figure 5.3-29: Line Recloser ACA Results

Distribution Capacitor

InnPower owns nine in-service distribution capacitors. The age demographics for this asset class are provided in Figure 5.3-30.

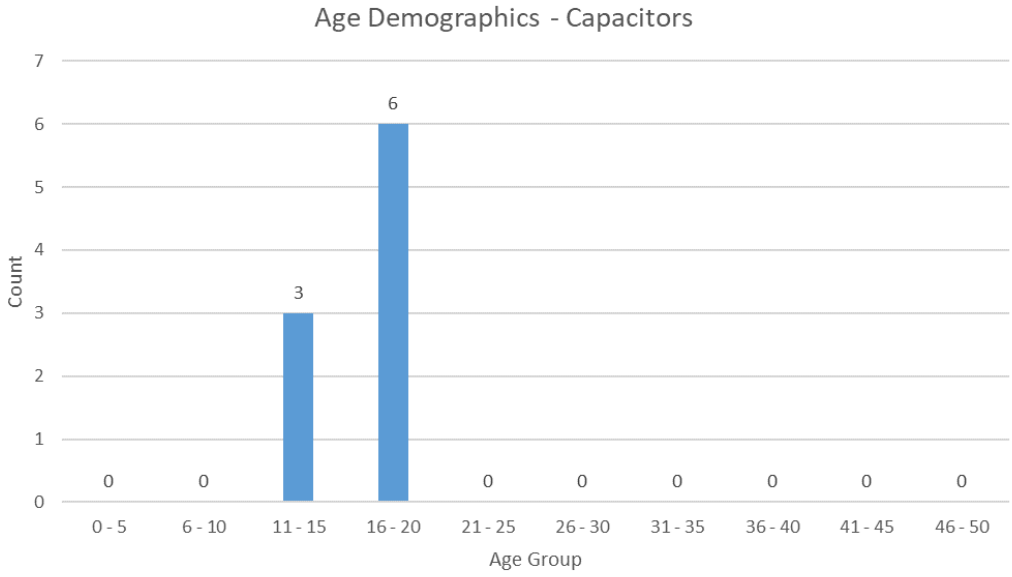


Figure 5.3-30: Capacitor Age Demographics

The HI distribution for capacitors is presented in Figure 5.3-31. All capacitors were assessed to be in very good or good condition.

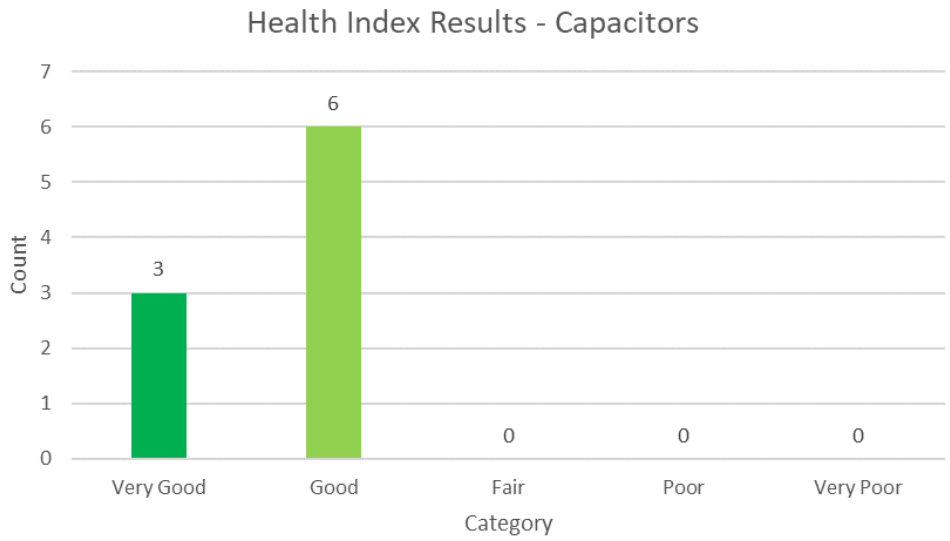


Figure 5.3-31: Distribution Capacitor ACA Results

Distribution of Motorized 44kV Switches

InnPower owns 36 44kV motorized switches within its service territory. The age demographics for this asset class are presented in Figure 5.3-32.

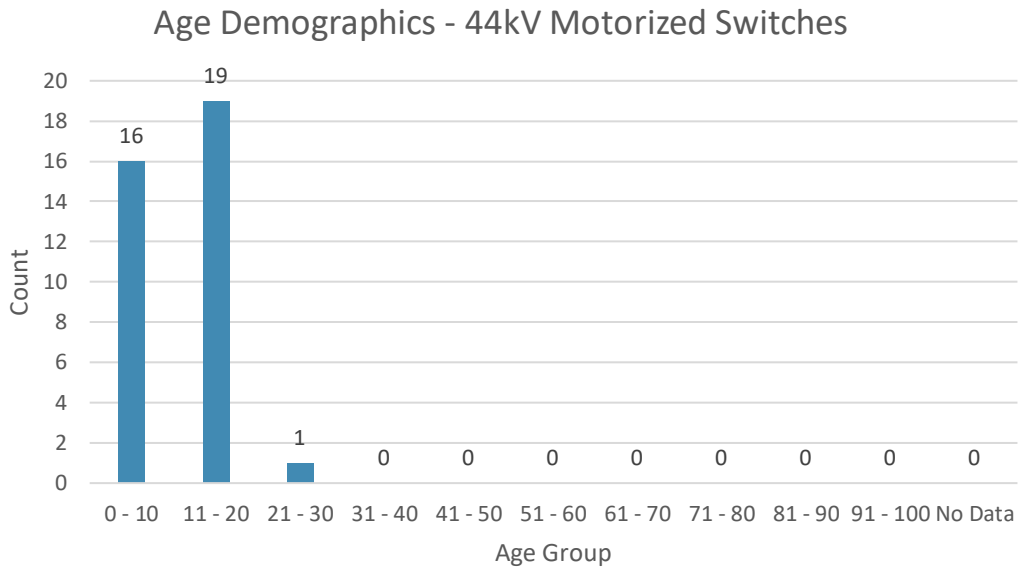


Figure 5.3-32: 44kV Motorized Switches Age Distribution

The overall 44kV switch HI distribution is presented in Figure 5.3-33. Fifty-six percent of the population was categorized as good or very good, with the remaining population being in fair condition and one unit in poor condition.

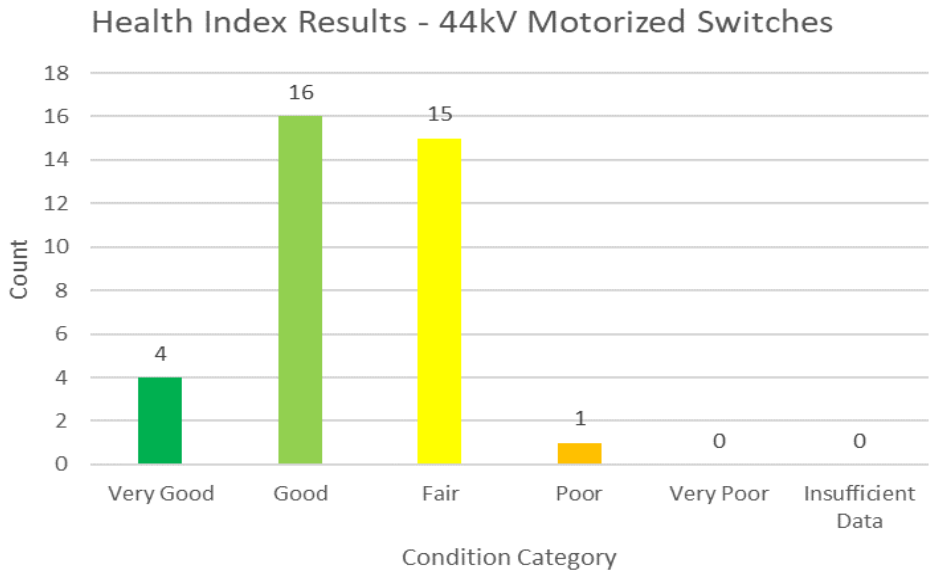


Figure 5.3-33: 44kV Motorized Switch ACA Results

Distribution SCADA-Mate Switches

InnPower owns six SCADA-Mate switches within its service territory. The age demographics for this asset class are presented in Figure 5.3-34.

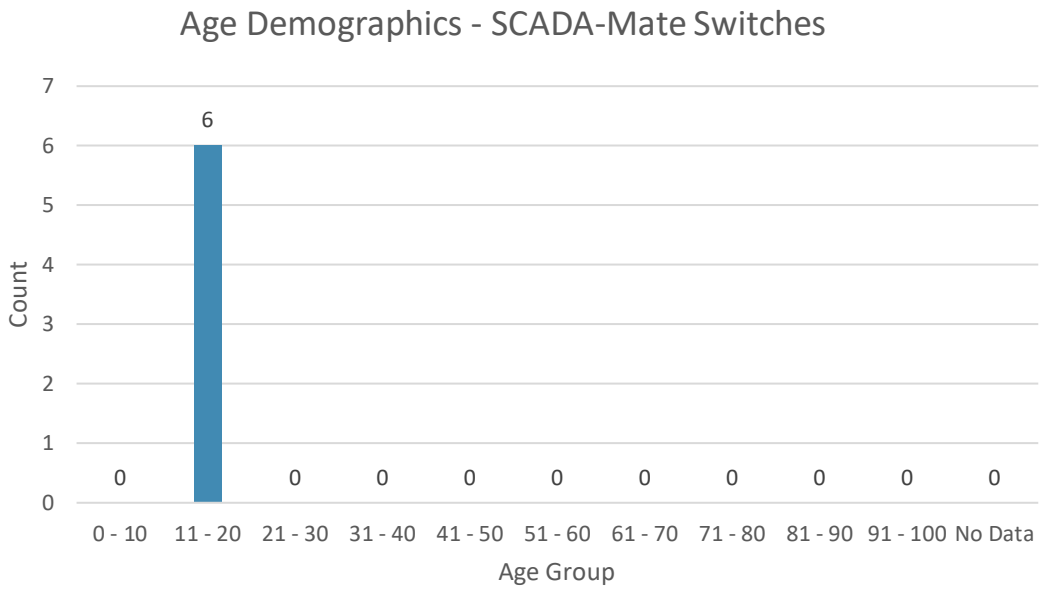


Figure 5.3-34: SCADA-Mate Switches Age Distribution

The overall SCADA-Mate switch HI distribution is presented in Figure 5.3-35. All the units assessed were categorized as good or very good.

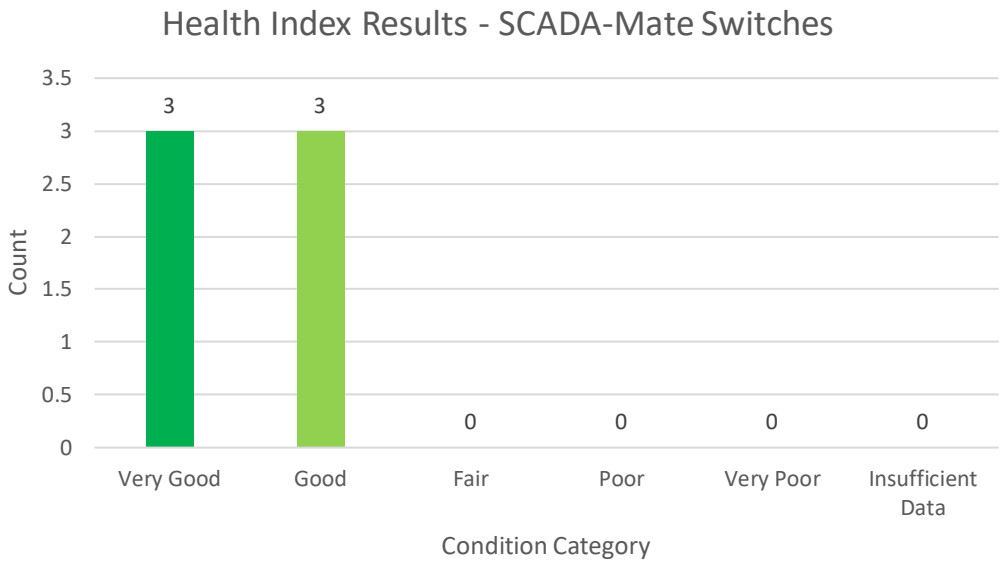


Figure 5.3-35: SCADA-Mate Switches ACA Results

Overhead Conductor

When the ACA was conducted, InnPower had 660 km of OH conductors. For OH conductors, data limitations prevented a full ACA from being completed, as only age data was available. The age demographics for this asset class are presented in Figure 5.3-36.

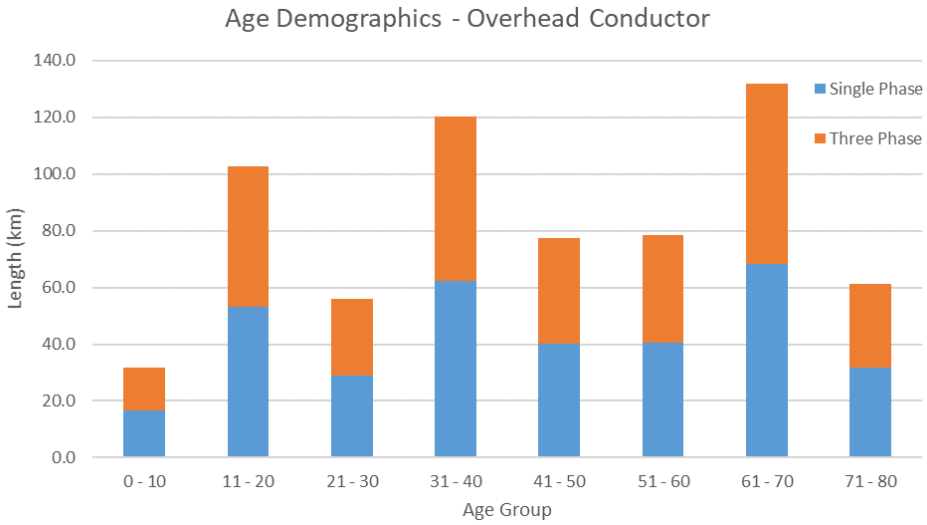


Figure 5.3-36: Overhead Conductor Age Demographics

The estimated typical useful life (TUL) is 60 years for this asset class. As can be seen above, approximately 29%, or 193.1 km, of conductors have already exceeded this threshold, and an additional 12%, or 78.3 km, are expected to exceed the TUL over the next ten years.

Underground Distribution (Padmount) Transformers

When the ACA was conducted, InnPower owned a total of 1,478 pad mount transformers within its service territory. The age distribution for this asset class is provided in Figure 5.3-37.

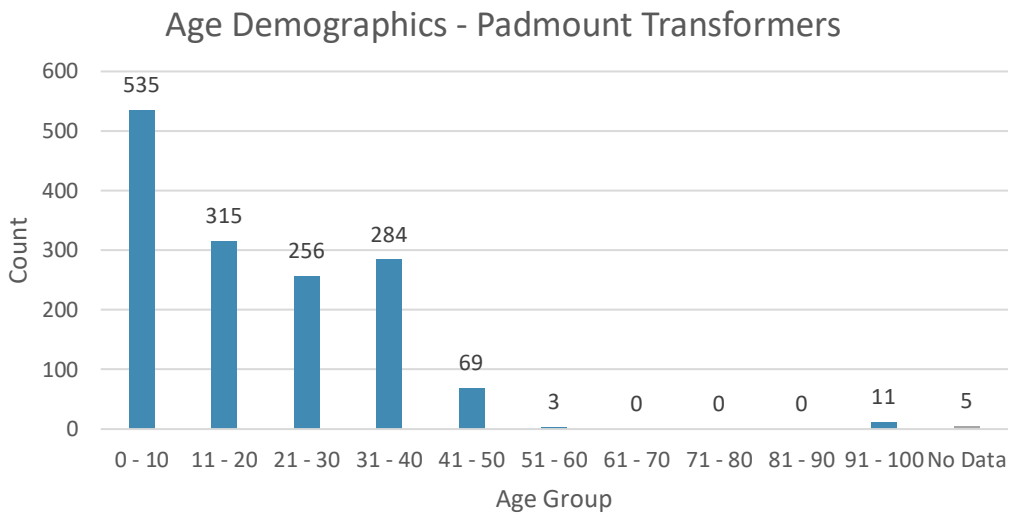


Figure 5.3-37: Distribution Pad Mount Transformer Age Distribution

This class is overall healthy, as 78% of the class is in the good or very good category, and only one asset is in the poor and very poor categories. When the ACA was conducted, it was determined that there was insufficient data to create an HI for 136 of the transformers, so the data was extrapolated using the assets that had sufficient data to have the HI distribution for the full class. The full HI results are presented below in Figure 5.3-38.

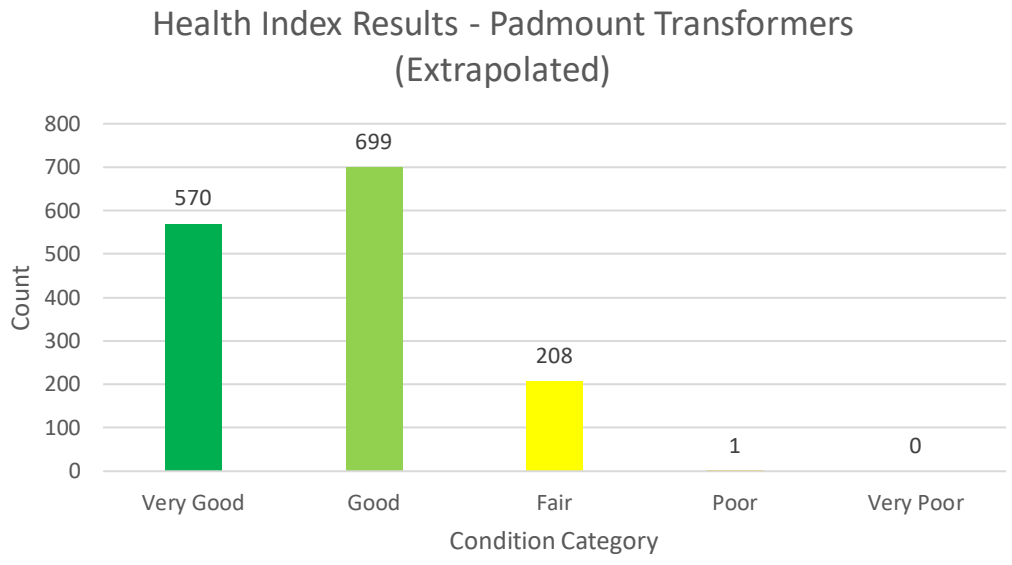


Figure 5.3-38: Underground Transformer ACA Results - Extrapolated

Distribution Pad Mount Switchgear

InnPower owns 67 Pad Mount Switchgears within its service territory. The age demographics for this asset class are presented in Figure 5.3-39.

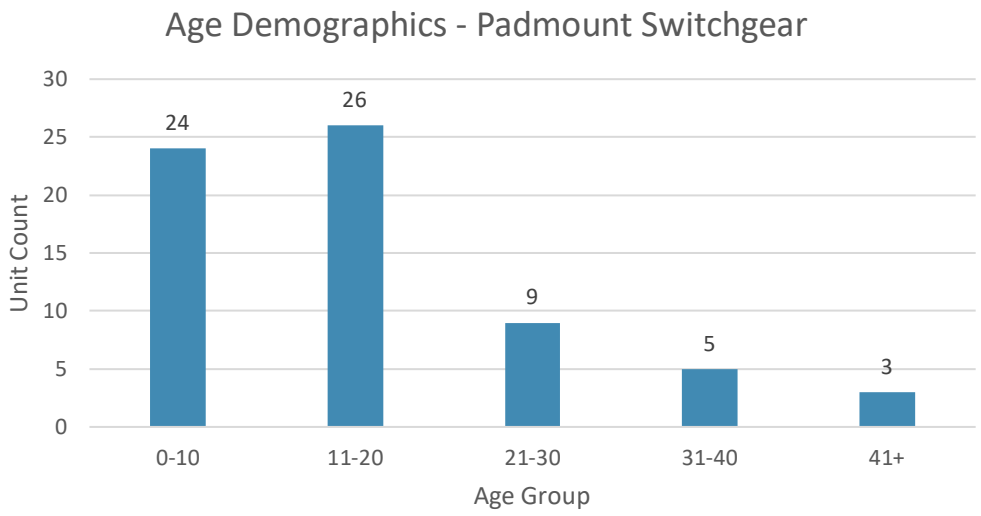


Figure 5.3-39: Distribution Padmount Switchgear Age Distribution

The condition assessment results are presented in Figure 5.3-40 below. Overall, this asset class is in a healthy state as most units (88% of the population) are classified as in good condition or higher. InnPower should investigate the eight units that are currently classified in the fair condition category as these assets may degrade to poor or very poor condition over the next five to ten years.

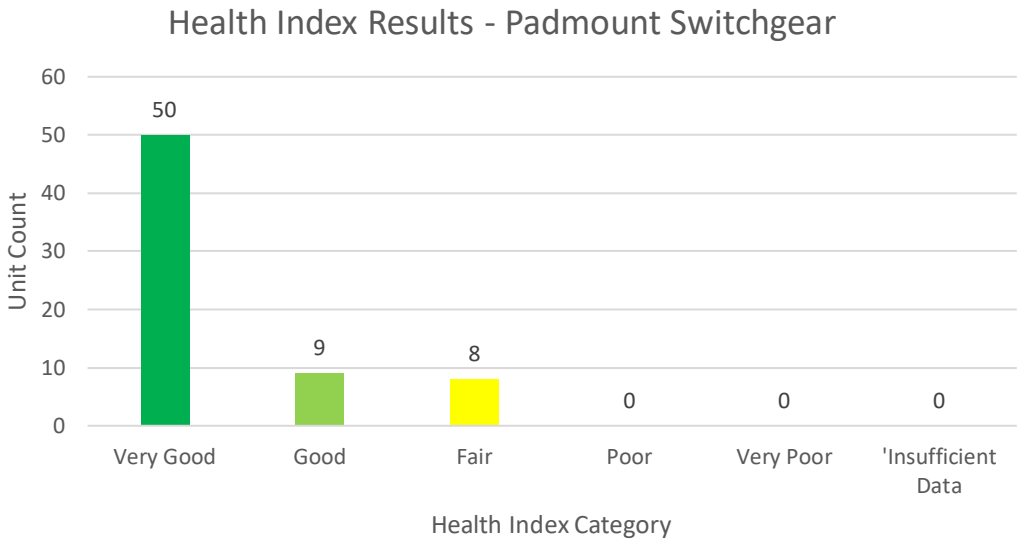


Figure 5.3-40: Distribution Pad Mount Switchgear HI Results

Underground Cable

When the ACA was conducted, InnPower had 173km of UG cable. For UG cable, data limitations prevented a full ACA from being completed, as only age data was available. The age demographics for this asset class are presented in Figure 5.3-41.

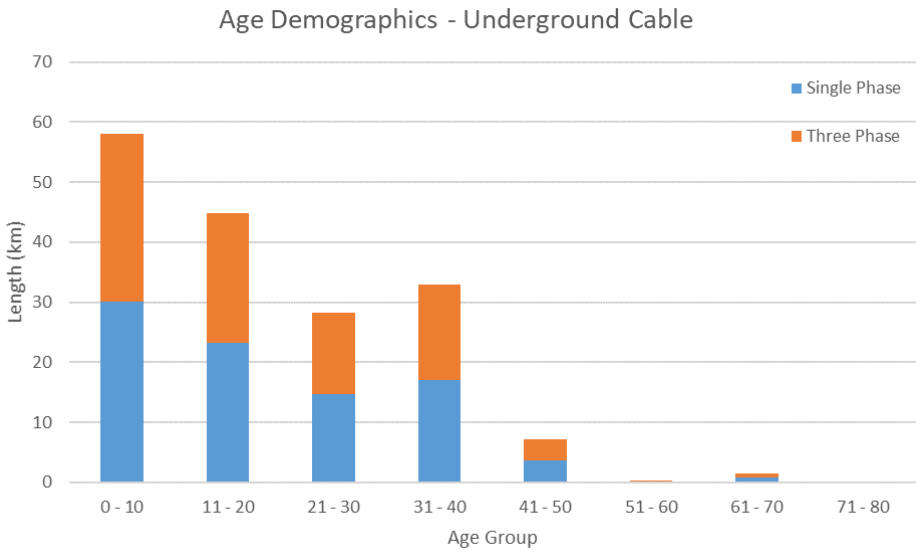


Figure 5.3-41: Underground Cable ACA Results

The estimated TUL is 40 years for this asset class. As can be seen above, approximately 5% of UG cable has already exceeded this threshold, and an additional 19% of the population is expected to exceed the TUL over the next ten years.

5.3.2.2.3 Asset Failures/Performance

Historical outages categorized by OEB Cause Codes were previously provided in section 5.2.3.2. For Cause Code *5-Defective Equipment*, InnPower takes this a step further by tracking defective equipment outages by asset type. The annual number of defective equipment outages recorded by asset type over the 2017 to 2022 period is summarized in Table 5.3-13 and Figure 5.3-42.

Table 5.3-13: Defective Equipment Outages by Asset Type

Asset Type	Number of Annual Failures						Total	Percent of Total
	2017	2018	2019	2020	2021	2022		
Arrestor	6	2	1	2	2	0	13	4.81%
Connection	6	4	3	5	1	3	22	8.15%
Cutout	0	0	2	4	2	0	8	2.96%
Fuse	13	26	1	6	1	4	51	18.89%
Insulator	1	0	0	0	0	1	2	0.74%
Linkets	7	1	0	1	0	0	9	3.33%
Meter	2	4	4	3	0	0	13	4.81%

Asset Type	Number of Annual Failures						Total	Percent of Total
	2017	2018	2019	2020	2021	2022		
Recloser	0	2	0	2	0	0	4	1.48%
Neutral	2	0	1	1	0	0	4	1.48%
Primary Conductor	0	1	1	1	0	0	3	1.11%
Secondary Conductor	9	4	13	17	1	5	49	18.15%
Sleeve	1	0	0	0	4	0	5	1.85%
Switch	2	4	6	3	0	1	16	5.93%
Transformers	9	5	4	7	3	12	40	14.81%
Unknowns	11	11	8	1	0	0	31	11.48%
Total	**69**	**64**	**44**	**53**	**14**	**26**	**270**	**100.00%**

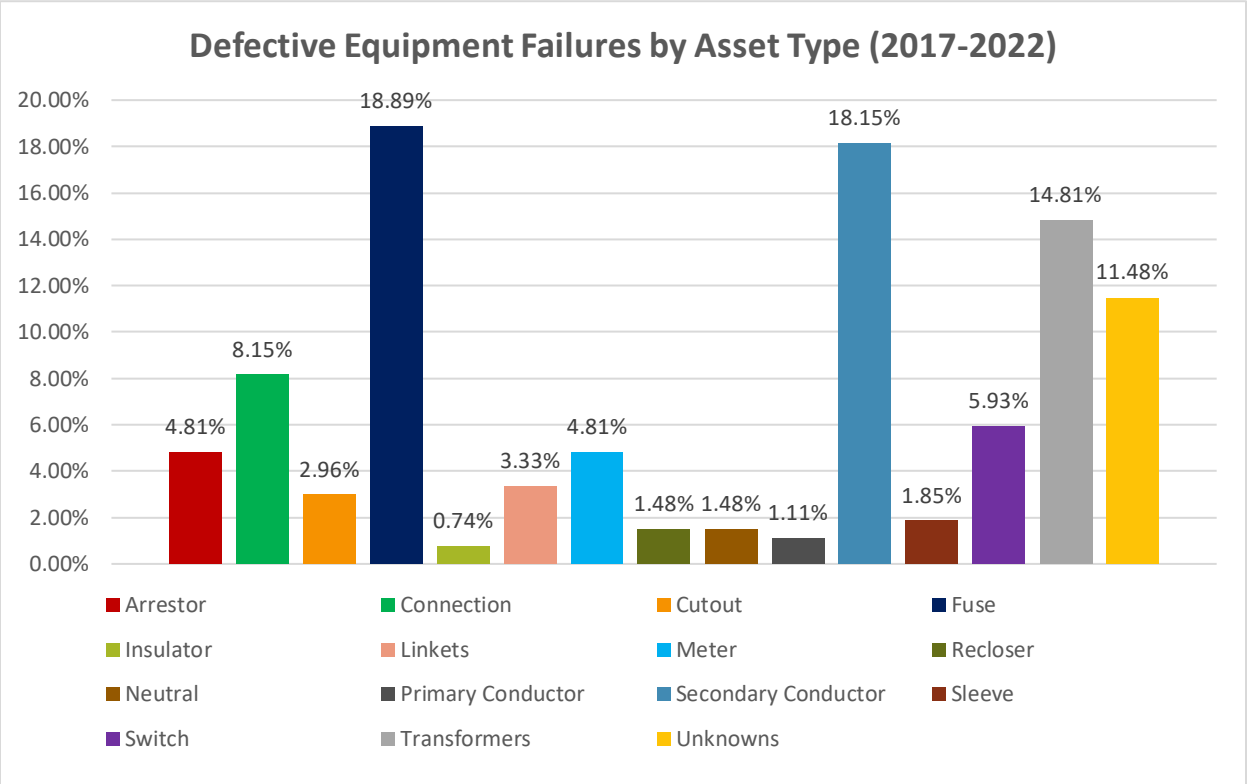


Figure 5.3-42: Defective Equipment Failures by Asset Type

5.3.2.2.4 Asset Risks

As previously noted in section 5.3.1, InnPower's AM strategy covers the full life cycle of a fixed asset, from the preparation of the asset specification and installation standards to the scope and frequency of preventative maintenance during the asset's service life and finally to the determination of the assets

end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs), and lowest operating costs.

Asset risks (probability of failure x consequence of failure) are considered as part of InnPower's prioritization process (step two of InnPower's AM process shown in Figure 5.3-1) and are ultimately used to determine the prioritized list of capital projects and programs over the forecast period. Additional information on this process can be found in section 5.3.1.2 and InnPower's list of prioritized projects for the test year is included in section 5.4.2.1.

5.3.2.3 Transmission or High Voltage Assets

There should also be a statement as to whether the distributor has had any transmission or high voltage assets (>50kV) deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the present application.

InnPower does not have any transmission or high voltage assets above 50 kV deemed previously. InnPower is planning on building a new 230 kV InnPower TS during the forecast period. Once these assets are in-service, InnPower will seek for these assets to be deemed as distribution assets by the OEB.

5.3.2.4 Host and Embedded Distributors

A distributor should also provide a description of whether the distributor is a host distributor (i.e.: distributing electricity to another distributor's network at distribution-level voltages) and/or an embedded distributor (i.e.: receiving electricity at distribution-level voltages from any host distributor(s)). The distributor must identify any embedded and/or host distributor(s). Partially embedded status (i.e.: where part of the distributor's network is served by one or more host distributors but where the utility is also connected to the high-voltage transmission network) must be clearly identified, including the percentage of load that is supplied through the host distributor(s). If the distributor is a host distributor, the distributor should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes (such as GS > 50 kW).

InnPower is embedded into the HONI sub-transmission system. InnPower is currently feeding its customers via four Hydro One distribution-level feeders; two feeders out of the Thornton DS (Feeders F1 and F2) and two feeders out of the Cookstown DS (Feeders F2 and F4). InnPower also supplies power to some HONI customers via a feeder out of Innisfil DS (Feeder F1). Additional information surrounding this can be found in Exhibit 1-1-9.

5.3.3 Asset Lifecycle Optimization Procedures and Practices

This section presents InnPower's asset lifecycle optimization and risk management procedures and practices. InnPower owns and operates assets within its service territory and is responsible for the management of all its distribution and station assets. InnPower maintains the efficiency and reliability of its system through active inspection, maintenance, and AM processes. The objective of InnPower's asset lifecycle optimization procedures and practices are to provide the highest quality of service to customers by ensuring the electrical system operates as designed, constructed, and maintained to ensure its reliability, safety, and affordability. The specific description of procedures and practices in the following sub-sections demonstrates how InnPower can meet its asset lifecycle objectives.

5.3.3.1 Asset Replacement and Refurbishment Practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of System Renewal investments and decisions to refurbish rather than replace system assets. The information provided should be sufficient to show the trade-off between spending on new capital (i.e.: replacement) and life-extending refurbishment.

InnPower considers a wide range of factors when deciding whether to refurbish or replace distribution assets, including but not limited to public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition, and life expectancy. All these factors are considered when determining the prudency of any asset replacement or refurbishment.

System Renewal spending is optimized and prioritized based on the ACA (see Appendix J). It is scheduled to align with budget envelopes through long-term planning and project prioritization. Long-term planning helps to smooth rate impacts, while project prioritization helps to limit rate impacts. A refurbishment strategy is applied to various assets through capital and maintenance programs, namely:

- Maintenance of 44 kV switches.
- Maintenance of line oil reclosers.
- Maintenance of substations and substation equipment.
- Substation rehabilitation.
- Transformer oil re-inhibition.
- Vehicle maintenance.

If the cost to refurbish or repair assets are greater than the replacement costs, the asset is replaced and disposed of appropriately. Where appropriate, removed, and repaired assets that are still in good working order are kept as spares.

5.3.3.2 Description of Maintenance and Inspection Practices

A distributor should also be able to demonstrate that it has carried out cost-effective system operations and maintenance (O&M) activities to sustain an asset to the end of its service life (and can include references to the Distribution System Code).

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. InnPower has revised and refreshed its annual Preventative Maintenance Program. It has undertaken a comprehensive overview of various asset classes, developed or updated the appropriate procedure,

determined an inspection frequency, and placed the necessary resources in place to inspect, replace and maintain complete records of work.

The Preventative Maintenance Program is categorized into broad sub-programs: vegetation management, OH inspection, OH maintenance, UG inspection, UG maintenance, and station inspection and maintenance. The OH inspection and maintenance program captures OH conductors, pole-mounted transformers, switches, reclosers, poles, and line hardware while the UG inspection and maintenance program captures Padmounted transformers and Padmounted switchgears. The station inspection and maintenance program contains a comprehensive list of station components requiring periodic inspection as well as infrared testing to identify hot spots and transformer oil sampling and application of re-inhibit treatment to prolong the life of station transformers.

Asset lifecycle optimization for an electric utility involves regular inspection and maintenance of the assets. InnPower's asset inspection and maintenance practices are summarized in Table 5.3-14.

Table 5.3-14: InnPower's Asset Inspection and Maintenance Practices and Schedules

System	Asset	Practice	Schedule
Overhead distribution assets	44 kV switches and conductors	Infrared and Visual inspection	Three-year cycle
	44 kV switches	Maintenance	Five-year cycle
	Poles	Testing and Visual Inspection	Six-year cycle
	Distribution overhead	Infrared and Visual inspection	Three-year cycle
	Overhead	Tree trimming	Four-year cycle
	Polemount Transformers	Infrared and Visual inspection	Three-year cycle
	Voltage Regulators	Inspection (part of three-year cycle Infrared)	Three-year cycle
	Capacitor banks	Inspection (part of three-year cycle Infrared)	Three-year cycle
	Oil Reclosers[1]	Maintenance	Four-year cycle
Underground distribution assets	Padmount Transformers and switchgear	Visual inspection	Three-year cycle
Station assets	Distribution station	Visual inspection	Monthly
	Distribution station	Infrared	Yearly
	Station equipment (transformer testing, arrestor, termination, tap changer, etc.)	Maintenance	Four-year cycle
	Transformer oil	Oil test (Dissolved Gas Analysis (DGA), furan analysis, oxidation inhibitor, Polychlorinated Biphenyl (PCB))	Yearly
Fleet assets	Large vehicles	Vehicle maintenance, hydraulic maintenance, and inspection	Quarterly

System	Asset	Practice	Schedule
	Large vehicles	Dielectric test and Commercial vehicles Operators Registration (CVOR) inspection	Yearly
	Large and small vehicles	Engine fluids	Every three to four months
	Large and small vehicles	Rust-proofing	Yearly

[1] Over the forecast period, InnPower is planning to phase out its remaining oil reclosers. These units will be replaced with dielectric units that are SCADA controllable to increase reliability and reduce environmental impacts.

5.3.3.2.1 Overhead Lines

Vegetation and right of way (ROW) control is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. InnPower has a large rural and urban area where OH lines are in proximity to trees. In an effort of mitigating direct contact between trees and distribution assets, tree trimming is currently conducted on a four-year cycle. InnPower does not have any in-house tree trimming personnel or equipment and therefore uses an independent contractor at market rates. Depending on the size, shape, and growth aspect of relevant trees, the arborists remove sufficient foliage from the tree to limit the possibility of contact within a four-year time frame. Following tree trimming, the independent contractor removes all debris and returns the site to as-found condition. Any pole line damage or anomaly noticed by the tree trimming crew is reported to InnPower for remedial action.

InnPower also contracts out infrared scanning on its high-voltage assets on a three-year cycle. Any abnormal condition is reported to InnPower for remedial action and critical abnormalities are reported to InnPower for immediate action.

Line patrol is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Line patrol may highlight problems or identify conditions that warrant a more thorough inspection or the need for maintenance. Visual inspections of major distribution system components identify problems and hazards such as leaning poles, damaged equipment, damaged enclosures, and vandalism. Line patrols can identify potential failures before they occur, thereby improving system reliability, avoiding repair costs, and avoiding insurance claims.

Line patrol includes a visual inspection of all related equipment as follows:

- Conductors and Cables:
  - Low conductor clearance.
  - Broken/frayed conductors or tie wires.
  - Tree conditions, exposed broken ground conductors.
  - Broken strands, bird caging, and excessive or inadequate sag.
  - Insulation fraying on secondary (i.e.: open wire)
- Poles/Supports:
  - Bent, cracked, or broken poles.
  - Excessive surface wear or scaling.

  - Loose, cracked, or broken cross arms and brackets.
  - Woodpecker or insect damage, bird nests.
  - Loose or unattached guy wires or stubs.
  - Guy strain insulators pulled apart or broken.
  - Guy guards out of position or missing.
  - Grading changes or washouts.
  - Indication of burning.

- Hardware and Attachments:
  - Loose or missing hardware.
  - Insulators unattached from pins.
  - Conductor unattached from insulators.
  - Insulators flashed over or obviously contaminated.
  - Tie wires unraveled.
  - Broken or removed ground wire.
  - Ground wire guards removed or broken.

- Vegetation and Right of Way:
  - Leaning or broken “danger” trees.
  - Growth into the line of “climbing” plants.
  - Unapproved/unsafe occupation or secondary use.

Line patrol is also performed by line personnel and engineering staff when a problem has been identified within a circuit via SCADA or customer calls. Additionaly InnPower’s line crew inspects and reports damages when driving through InnPower’s distribution territory daily. Distribution system problems are either remedied immediately or scheduled for remedial action.

5.3.3.2.2 Poles

Pole inspection is carried out as part of InnPower’s infrared and visual inspection programs, and details of anomalies are submitted to InnPower on a three-year cycle. InnPower’s internal crews carry out repairs as needed based on the results of those inspections (e.g.: back guy tightening, tightening loose bolts, addressing leaning poles or conductor sag, etc.). Over time, wood poles shrink, wear, and deteriorate to a point that original installations become loose. With weather elements such as wind and ice loading, hardware can eventually loosen and fail.

Pole inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. InnPower’s population of poles includes species of Jack Pine, Red Pine, Western Red Cedar, and Yellow Cedar, and ranges from 30 to 90 feet in height. These species are treated with creosote, chromium copper arsenate, or pentachlorophenol to extend the life of the wood. Currently, there are no steel or composite poles in service, but there are two concrete poles installed where the 9M6 feeder enters Innisfil and two sets of steel structures are planned to be installed in 2024.

The majority of wood pole deterioration occurs at the pole butt where the pole enters the ground. It is the area flush with the ground that receives the greatest impact of moisture and oxygen that enables the rotting of the pole which occurs from the inside out. Poles are, therefore, tested to see the extent to which they are hollow. The extent to which the pole is structurally sound correlates to the pole's ability to withstand vertical structural loading, such as transformers, switches, and hardware, and horizontal structural loading such as wind shear. Poles that lack structural integrity are at risk of falling.

InnPower has been implementing a six-year pole testing cycle. The poles are tested using non-destructive devices that measure the moisture content of the wood just above ground level. The higher the moisture level within the wood, the greater the extent of the deterioration. When a threshold level of moisture is detected, a resistograph or polux is used to physically measure the extent of the deterioration. The pole testing results are logged, and pole replacement is scheduled as required. Along with the pole testing results, the poles are numbered, tagged with a GPS coordinate, tagged with other hardware and nomenclature, and input into the GIS.

Pole replacements are undertaken for several reasons, including:

- Pole decomposition or structural damage.
- Vehicle accidents.
- Customer service requests requiring a taller pole or a different pole class.
- Road widenings and grade changes.
- Line rebuilds.
- ESA compliance.

InnPower replaces poles that may exhibit a health and safety hazard to the public and staff. Each year, one-sixth of InnPower wood poles are tested and rated to determine when they should be replaced or retested. Poles are replaced as required to maximize the health and safety of the public, system reliability, and the ability to connect new customers. Pole replacements are all done to current ESA requirements.

5.3.3.2.3 Switches

Switch inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Fused switches (cut-outs) accept different sizes of fuses, which are used for the protection of lines, equipment, or transformers from main feeder amperages. Fused cut-outs are inspected during the infrared scanning process and are replaced once they fail. When fused cut-outs fail with an abnormal frequency, fused cut-out statistics are investigated to see if a manufacturer's defect has occurred. If a manufacturer's defect is suspected, then all related fused cut-outs may be replaced as an act of due diligence. Failure to do so would not only decrease reliability and the safety of operational personnel would be compromised.

Load break and air break switches are located predominately on the 44 kV system and perform switching operations to allow for maintenance and emergency procedures. These switches are maintained on a five-year cycle, and inspections carried out by the infrared scanning process are completed on a three-year cycle.

There are numerous in-line switches and mid-span openers on the 44 kV, 27.6 kV, and 8.32 kV system. Infrared scans will detect hotspots and identify any deficiencies in the system which will then be replaced later.

Switch replacements are undertaken for several reasons, including:

- Mechanical or electrical failure.
- Vehicle accidents.
- Lightning strikes.
- New customer requirements.
- Road reconstruction.
- Line rebuilds or circuit reconfigurations.
- ESA compliance.
- Systematic failures involving a particular manufacturer or style.

5.3.3.2.4 Reclosers

Recloser inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. These devices are programmable switches that open and close depending on how the current limits are set. The load is broken within an oil bath or vacuum chamber for dielectric purposes. After several operations, the oil bath becomes contaminated with carbon, which is formed by the oxidation of the oil by the arc quenching process. The carbon-impregnated oil loses dielectric properties and needs to be inspected and the oil replaced. The oil reclosers are inspected and rebuilt once every four years and undergo regular infrared scans. Damaged reclosers are replaced as required.

Over the forecast period, InnPower is planning to phase out its remaining oil reclosers. These units will be replaced with dielectric units that are SCADA controllable to increase reliability and reduce environmental impacts. Only visual inspection and infrared will be conducted on the new units as they are self-contained with no operable parts to maintain.

5.3.3.2.5 Overhead Transformers

OH transformer inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Transformers transform high distribution voltage into low voltage (less than 750 V) that can be used by customers. All transformers have had their mineral oil tested and verified so that all transformers are PCB-free (less than 50 ppm). All transformers are visually inspected every three years to gain efficiencies in inspection practices as InnPower continues to experience rapid growth in its service territory. The transformer inspection frequency is in accordance with the Minimum Inspection Requirements stated in the DSC.

The typical line patrol inspections address the following issues:

- Leaking or corroded transformers.
- Hot connects via infrared scanning.
- General appearance.
- Transformers below the neutral.
- Loose wires.
- Bird or animal nests.

Transformers are changed with different-sized units as needed. Transformers are replaced when they fail due to a lightning strike, vehicle accident, potential oil leakage, or internal/external problems.

5.3.3.2.6 Voltage Regulators

Voltage regulator inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Voltage regulators are single-phase devices that are situated on high-voltage lines, far away from the DS. When line losses drop the voltage potential below acceptable levels, the voltage regulators increase the line voltage to within Canadian Standard Association (CSA) standards. InnPower's voltage regulators are patrolled and undergo infrared scanning on a three-year cycle.

5.3.3.2.7 Capacitors

Capacitor inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. When AC power flows through the conductor, there is a loss of power in the conductor due to its resistance and reactance. Capacitor banks are installed to reduce line losses, improve power factor, and balance feeders for easier switching. InnPower has nine sets of capacitor banks in its distribution system and additional locations may be identified when system planning activities are completed. Capacitors banks are inspected every three years and damaged capacitors are repaired or replaced as required.

5.3.3.2.8 Underground Cables

UG primary cable inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. With respect to UG systems, riser poles are checked by OH patrols with a visual check of cable, cable guards, terminators, and arrestors. While it is not possible to visually inspect UG cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface.

UG secondary service inspection is also a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Old bus work loses its insulation due to ultraviolet radiation and other weather-related factors and is becoming a danger to working utility staff and wildlife. The old secondary bus is removed from service and a new, larger bus is installed. Secondary services with a premature failure rate are repaired or replaced as required.

5.3.3.2.9 Padmounted Switchgear and Transformers

Padmounted switchgear inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Switching cubicles are visually inspected every three years in accordance with the Minimum Inspection Requirements stated in the DSC. Damaged switching cubicles are repaired or replaced as required.

Padmounted transformer inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. All transformers have had their mineral oil tested and verified so that as of 2005, all transformers are PCB-free (less than 50 ppm). Transformers are visually inspected on a three-year cycle. UG transformers have their lids opened and visual inspections are conducted. Damaged transformers or components are repaired or replaced as required. All Padmounted transformers are numbered, and their secondary services are tagged, as are the high-voltage elbows. Typically, Padmounted transformer inspections address the following issues:

- Rust/corrosion causing public safety issues.
- Lock and penta-bolt in place.

- General appearance.
- Pad/vault placement.
- Leaking oil.
- Loose wires.
- Bird or animal nests.

High voltage elbow and UG cable terminator inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. The standard for UG distribution is to use 28 kV class equipment even on 8.32 kV distribution. This standardization improves reliability and allows for easier voltage conversion upgrades. Elbows and terminators are visually inspected every three years in accordance with the Minimum Inspection Requirements stated in the DSC. Damaged elbows and terminators are repaired or replaced as required.

5.3.3.2.10 Distribution Stations

DS inspection is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Inspections are undertaken monthly for both rural and urban DS sites. The inspection involves the following parameters:

- Theft of copper.
- Vegetation.
- Fencing.
- Litter.
- Health and safety.
- Station grounding (visual).
- Condition of SCADA building.
- Transformer temperature.
- Recloser operations.
- Transformer leakage.
- Tap changer leakage.
- Transformer winding temperature.
- Tap changer counters.
- Top oil temperature.
- Oil level.
- Transformer fans.
- Pest control for control building.
- Lighting and security.

- Pot heads and insulators.
- Battery test and direct current (DC) control.
- SF6 level for padmount switches.

Annual DS maintenance includes weed and vegetation control, grass cutting, snow plowing, and SCADA maintenance. On a four-year rotation, InnPower's DS are taken out of service so that major maintenance can be performed. This maintenance service includes the following:

- Bus connection inspection and tightening.
- Ground resistance test.
- Transformer oil analysis.
- Switch cleaning and lubrication.
- Inspection and cleaning of terminators, insulators, and arrestors.
- Cleaning of site, structures, and hardware.
- Transformer routine testing (such as turns ratio, resistance test, solid dielectric test, power factor test, etc.).
- Manually and remotely testing all station equipment operations (by confirming all telemetries and remote points).
- Cable testing if required (such as high pot, very low frequency (VLF) tan delta).

Substation maintenance crews generally perform major service over a one- to two-day period. Failure to perform major services could affect system reliability and the lifespan of the related equipment.

5.3.3.2.11 Vehicles

The operation, maintenance, and replacement of InnPower's fleet vehicles are guided by InnPower's Fleet Management Policy and New Vehicle Replacement Procedure. The primary criteria best suited for the decision to replace InnPower vehicles are provided in Table 5.3-15 below. Vehicles deteriorate differently depending on factors such as quality of manufacture and the severity of usage. The Fleet Management Policy and Vehicle Replacement Procedures are not intended to be a stringent set of rules that do not allow for the flexibility needed for AM but are a working target.

Table 5.3-15: Primary Criteria for Vehicle Replacement

Vehicle	Replacement Age	Replacement Usage
Pickup truck, van, car	Ten years	200,000 km
Dump truck (all sizes)	Ten to 20 years	220,000 km or 10,000 hours
Large, specialized equipment	Ten to 20 years	10,000 hours

Different vehicles and equipment also wear out more rapidly than others depending on their usage type and frequency. To incorporate vehicles and equipment not referenced in the above criteria, there must be a second type of criteria used for this type of evaluation in addition to the above or on an individual basis. Table 5.3-16 presents the secondary criteria for vehicle assessment.

Table 5.3-16: Secondary Criteria for Vehicle Assessment

Factor	Points		
Age	One point for each year of chronological age, based on in-service data.		
Kilometres/Hours	One point for each 16,000 km, 640 hours = one point		
Type of Service	One, three, or five points are assigned based on the type of service that the vehicle receives. For instance, a road patrol car would be given a five because it is in severe duty service. In contrast, an administrative sedan would receive a one.		
Reliability	Points are assigned as one, three, or five depending on the frequency that a vehicle is in the shop for repair. A five would be assigned to a vehicle that is in the shop two or more times per month on average, while a one would be assigned to a vehicle in the shop an average of every three months or less.		
Maintenance and Repair (M&R) Costs	One to five points are assigned based on total life M&R costs (not including repair of accident damage). A five is assigned to a vehicle with life M&R costs equal to or greater than the vehicle's original purchase price, while a one is given to a vehicle with life M&R costs equal to 20% or less of its original purchase cost.		
Condition	This category takes into consideration body condition, rust, interior condition, accident history, anticipated repairs, etc. A scale of one to five points is used with five being poor condition.		
Point Ranges	Under 18 points	Condition I	Excellent.
	18 to 22 points	Condition II	Good.
	23 to 27 points	Condition III	Qualifies for replacement.
	28 points and above	Condition IV	Needs immediate consideration.

To maximize the useful life of its vehicles, InnPower evaluates the following practices for each vehicle:

- The availability to rotate vehicles between users to maximize the mileage driven with respect to the vehicle's age.
- The ability to transfer a vehicle to another department where usage is less severe or to address a need for a spare vehicle or spare parts.
- Analysis of whether the vehicle is in sufficiently good shape to extend its useful life beyond the age and mileage guidelines.

InnPower also analyzes factors that may decrease the useful life of a vehicle, including:

- Other facets or technologies required of the vehicle that can no longer receive maintenance support or uses parts or updates that can no longer be supplied.
- Analysis if the vehicle is a "lemon" (i.e.: expenses exceed depreciation), which may warrant an early retirement date.
- Analysis if the vehicle no longer has a useful purpose or is in sufficiently poor shape to warrant an early retirement date.
- Sufficient mechanical or structural damage caused by an accident or abnormal wear.
- A mechanical analysis supporting the early retirement of a vehicle.

Large vehicles receive quarterly maintenance, including hydraulic maintenance, and yearly rust-proofing. Small vehicles also receive yearly rust-proofing and are maintained on an as-needed basis. Vehicles that are no longer useful may be retired early to avoid unnecessary upkeep costs.

5.3.3.2.12 Property and Equipment

InnPower currently owns ten distribution substation sites, one 6.5-acre head office site, and three vacant lands (one of which is proposed for the new 230/27.6 kV 83MVA TS Project). These sites have the grass cut and snow plowed as required. InnPower also owns numerous registered easements and non-registered easements for distribution assets registered on title, requiring ongoing monitoring to protect the easement rights of InnPower. The head office requires interior maintenance, including the repair and replacement of office equipment.

Computer hardware includes phone systems, photocopiers, fax machines, printers, monitors, personal computers, network servers, power supplies, network cables, and wireless equipment. The parameters for the replacement of computer hardware are as follows:

- Improved space and speed requirements from new software.
- New technologies not supported by existing equipment.
- Existing equipment not supported by suppliers.
- Reliability problems from existing equipment.

When the need for expansion occurs and new computer equipment is purchased, displaced computer equipment is re-used or recycled to other areas of the corporation where appropriate.

5.3.3.3 Processes and Tools to Forecast, Prioritize and Optimize System Renewal Spending

A distributor should explain the processes and tools it uses to forecast, prioritize, and optimize System Renewal spending and how a distributor intends to operate within budget envelopes.

The inputs and processes for forecasting, prioritizing, and optimizing System Renewal spending are summarized in the following sub-sections. Additional information can be found in sections 5.3.1.2 and 5.3.1.3 of this DSP.

5.3.3.3.1 Forecasting

System Renewal projects are discretionary. The project needs for a particular period are supported by a multitude of factors, depending on the information available for each asset type. This could include a combination of asset inspection, individual asset performance, and condition information.

An ACA study was carried out by METSCO to establish the health and condition of distribution and substation assets in service. By considering all relevant information related to the assets' operating condition, the condition of all infrastructure assets was assessed and expressed on a normalized index in the form of a health index (HI). The HI was related to the probability of failure values for each project, using a weighted average approach, as described in detail in Appendix J, and each asset was assigned a health indicator expressed as "very good," "good," "fair," "poor," and "very poor." The resulting information from the ACA study was used to help forecast the renewal needs of InnPower's assets over the forecast period. Additional details on the inputs and processes used to forecast System Renewal spending are included in sections 5.3.1.2 and 5.3.1.3 of this DSP.

5.3.3.3.2 Prioritization and Optimization

For prioritizing capital expenditures, a distributor should help the reviewer understand the approaches a distributor uses to balance a customer's need for reliability and capital expenditure costs.

As previously detailed in section 5.3.1.3, discretionary System Renewal projects are selected and prioritized based on value and risk assessments for each project. Risk consequences related to reliability, safety, operating efficiency, etc. for each project area with assets found in "poor" or "very poor" condition are identified and calculated by multiplying the composite probability of asset failure with the consequence of failure. Costs for the scope of work to mitigate risk in each project area are determined, using distribution system estimating data. Through careful evaluation of the risks, projects are prioritized for implementation to mitigate higher-level risks during this DSP implementation period, while deferring the projects with lower-level risks or risks that can be managed through alternative cost-effective mitigation measures.

The prioritized System Renewal investments are paced for implementation based on the funding available for asset renewal and by considering the resources required for project implementation for the type of work predominantly involved (OH, UG, or substations).

The continued performance of assets is also managed through InnPower's capital investments and maintenance programs. InnPower's inspection, maintenance, and testing practices described previously in section 5.3.2.2 support asset life cycle risk management by rectifying deficiencies to extend the lives of the assets and identifying the assets in the very worst condition for replacement. Information obtained through asset databases, maintenance and inspection records, and outage records is a critical input into prioritizing and optimizing which projects will bring the best value.

5.3.3.3.3 Strategies for Operating within Budget Envelopes

The proposed System Renewal projects over the forecast period were identified to maintain system reliability and were paced for implementation based on the funding available for asset renewal and by considering the resources required for project implementation for the type of work predominantly involved. Assets with the highest consequence of failure in service have been prioritized for renewal or rehabilitation during the next five years.

However, since InnPower's AM process is continually being updated with new information, InnPower completes investment planning on an annual basis to help inform any necessary budget adjustments for the following year. InnPower understands that circumstances may change, and if needed, budgets can be re-prioritized depending on customer and system needs. For example, due to the non-discretionary nature of System Access projects, these projects will take priority if there are competing demands with System Renewal projects. Completing investment planning on an annual basis allows InnPower to use the best available information to effectively plan for and manage the highest priority projects and programs over the forecast period while remaining within the approved budget envelopes. As described in section 5.3.1.3, InnPower also monitors the execution of projects against budgets and makes changes as required to stay within overall budget envelopes.

5.3.3.3.4 Risks of Proceeding/Not Proceeding

A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures.

InnPower employs the results of visual inspections, in-situ testing, and service age of assets to determine the condition of assets by deriving a HI for each asset. The HI is related to the probability of failure for the asset by relating the health of the asset to an effective age and corresponding known

failure curve. The probability of failure data is multiplied by the consequences of failure for assets within a project area to arrive at a risk score. Consequences of failure are derived from the analysis of each project area and classification in terms of potential impacts on worker and public safety, the environment, reliability, and operational effectiveness that could arise if a failure event occurs. Once the risk (probability x consequence) of each project area has been established it is placed into a prioritization and selection process (i.e.: step two of InnPower's AM process shown in Figure 5.3-1) that determines which projects require action and the extent of the action that is necessary to minimize unacceptable risks.

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process and is ultimately used to determine the prioritized list of capital projects and programs over the forecast period. It is at this stage of the process that InnPower considered the risks associated with proceeding versus not proceeding with an individual capital expenditure and decides whether the capital expenditure is required during the forecast period or if it can be deferred.

Assets with unacceptably high-risk scores are monitored closely and plans are included in the project scope to alternatively maintain, refurbish, or replace the assets to reduce the risk to an acceptable level. It is noteworthy that some assets carry an inherently higher risk than others. For example, power transformers at stations have a higher nominal risk level associated with them in relation to pole mount transformers. Assets with low HI and higher consequence risk are given a priority for replacement, while assets with low HI but lower consequence risk are given a lower priority for replacement. The top projects in each category are identified in the prioritization process and scrutinized using further investigation and expert opinion to eliminate data inconsistencies and determine appropriate scopes of work. Additional information on this process can be found in section 5.3.1.3.

5.3.3.3.5 Consideration of Future Capacity Requirements

A distributor should also be able to demonstrate that in planning the lifecycle of an asset, it has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints.

Future capacity requirements are considered part of both system planning and engineering.

InnPower undertakes load studies to identify areas that may require investments to accommodate the required capacity. This is a key input considered as part of InnPower's AM processes. InnPower also engages regularly with customers, developers, municipalities, MTO, the IESO, and other LDCs to share information, identify needs, identify upcoming project plans, and coordinate long-term planning such that the needs of all parties can be considered.

When it comes to managing its assets and planning for replacements, InnPower will consider what alternatives are available. Various aspects are taken into consideration when evaluating alternatives, including potential development opportunities, and planning for increased load requirements such as electric vehicle charging stations. While like-for-like replacement may be appropriate in some cases, upgrades (such as installing a larger-sized distribution transformer or constructing a new circuit) may be pursued to address overloading issues, accommodate future load requirements, or address other identified constraints. This is considered on a case-by-case basis.

5.3.3.4 Important Changes to Life Optimization Procedures, Processes, and Tools since Last DSP Filing

A distributor should provide a summary of any important changes to the distributor's asset life optimization policies, processes, and tools since the last DSP filing.

Since the last DSP filing, InnPower has implemented some enhancements and evolutionary changes to support continuous improvement within its asset lifecycle optimization procedures and processes. This includes:

- **Preventative Maintenance Program:** InnPower has revised and refreshed its annual Preventative Maintenance Program. It has undertaken a comprehensive overview of various asset classes, developed or updated the appropriate procedure, determined an inspection frequency, and placed the necessary resources in place to inspect, replace and maintain complete records of work. The Preventative Maintenance Program is categorized into broad sub-programs: vegetation management, OH inspection, OH maintenance, UG inspection, UG maintenance, and station inspection and maintenance.
- **Updates to Fleet Policy:** InnPower recently updated its Fleet Management Policy and is in the process of developing a new Vehicle Replacement Procedure. These changes help clarify and provide parameters for the maintenance and upkeep of fleet vehicles.

5.3.4 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

Restricted Feeders

A distributor should provide a list of restricted feeders by name, the feeder designation, the reason for the restriction, and the number of connected customers, and explain if there are plans to improve their distribution system's ability to connect distributed energy resources.

InnPower's restricted feeders are identified in Table 5.3-17. Feeders which are nearing their maximum available capacity (i.e.: 20 kW or less of capacity remaining) are identified in yellow, and feeders that have no capacity remaining, are shown in red.

Table 5.3-17: Restricted Feeders (Current as of January 31, 2023)

Station	Substation DS	Restricted Feeder	Number of Connected Customers	Maximum DG Capacity [kW]	Remaining Capacity Available* [kW]
Alliston TS	Brian Wilson T1	F2	8	79.2	1.00
	Brian Wilson T2	F4	7	63.4	(9.34)
	Innisfil	F1	7	234	5.00
	Lefroy	F2	0	0	0.00
	Leonard's Beach	F2	0	0	0.00
Barrie TS	Stroud	F1	7	110.9	(167.29)
	Stroud	F2	0	11.1	11.10

**Feeders nearing their maximum available capacity (i.e.: 20 kW or less of capacity remaining) are identified in yellow, while feeders that have no capacity remaining are shown in red.*

At the time of the preparation of the DSP InnPower did not have specifically targeted plans at improving the distribution system's ability to connect DERs. InnPower is monitoring OEB and IESO initiatives with respect to DERs. However, some upgrades are either currently underway or are planned over the forecast period to address InnPower's growing load (e.g.: InnPower is actively

working with a developers group to upgrade the Brian Wilson T2 transformer to address load growth in areas covered by Brian Wilson T2). Since there is a direct relation between the available DER capacity on a feeder and the amount of load that feeder feeds, an added benefit of the planned system upgrades combined with InnPower's growing load will be an increased ability to connect DERs. This will enable InnPower to add DERs to Lefroy F2 and Leonard's Beach F2 as well as add DERs to Brian Wilson F2 and F4 as highlighted above and increase the restricted limitation.

Costs to Accommodate and Connect REG Facilities

If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities (e.g.: connection assets, expansions and/or renewable enabling improvements, etc.) that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the Ontario Energy Board Act, 1998, then a distributor should refer to Appendix A.

There are no costs included in this DSP to accommodate and connect REG facilities over the forecast period.

5.3.5 CDM Activities to Address System Needs

The OEB's 2021 Conservation and Demand Management Guidelines for Electricity Distributors (the CDM Guidelines) provide updated OEB guidance on the role of conservation and demand management (CDM) for rate-regulated electricity distributors, taking into account the provincial 2021-2024 CDM Framework and previous provincial CDM frameworks, and addressing the treatment of CDM activities in distribution rates. The CDM Guidelines require distributors to make reasonable efforts to incorporate CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. CDM activities potentially eligible for distribution rate funding are not limited to energy efficiency programs and include activities that reduce instantaneous electricity demand, including demand response and energy storage.

A distributor's DSP should describe how it has taken CDM into consideration in its planning process. The degree of consideration of CDM in meeting system needs should be proportional to the expected benefits, and will likely vary across distributors, taking into account the size and resources of a distributor. CDM will not be a viable alternative for all types of traditional infrastructure investments. Distributors are encouraged to take account of learnings from CDM activities that have been undertaken by other electricity distributors, in Ontario or elsewhere.

Distributors may apply to the OEB for funding through distribution rates for CDM activities as specified in the CDM Guidelines. Any application for CDM funding to address system needs must include a consideration of the projected effects on the distribution system on a long-term basis and the forecast expenditures. Distributors must explain the proposed activity in the context of the distributor's DSP, including providing details on the system need that is being addressed, any infrastructure investments that are being avoided or deferred as a result of the CDM activity (could include investments upstream of a distributor), and the prioritization of the proposed CDM activity relative to other system investments in the DSP.

Distributors should describe their approach to assessing the benefits and costs of CDM activity. However, the CDM Guidelines recognized that the Framework for Energy Innovation's (FEI) near-term

activities include defining an approach to assessing the benefits and costs of distributed energy resources and may apply approaches from the FEI in the future.

InnPower considers CDM as part of its planning process (see section 5.3.1.3) to determine whether CDM can be considered a viable alternative to any of InnPower's planned investments over the forecast period. However, no viable CDM alternatives have been identified currently. As a result, there are no CDM activities currently planned over the forecast period. InnPower will continue to consider the ability to use distribution rate funded CDM to potentially defer or avoid investments.

5.4 CAPITAL EXPENDITURE PLAN

The capital expenditure plan should set out and comprehensively justify a distributor's proposed expenditures on its distribution system and General Plant over a five-year planning period, including investment and asset-related O&M expenditures.

A distributor's DSP details the system investment decisions developed on the basis of information derived from its planning process. It is critical that investments be justified in whole or in part by reference to specific aspects of that process. As noted in section 5.2, a DSP must include information on the historical and forecast period.

This section summarizes InnPower's capital expenditure plan that has been developed to meet InnPower's strategic corporate objectives. The capital expenditure plan was developed based on the AM process previously described in section 5.3.

5.4.1 CAPITAL EXPENDITURE SUMMARY

The purpose of the information filed under this section is to provide a snapshot of a distributor's capital expenditures over a ten-year period, including five historical years and five forecast years. Despite the multi-purpose character a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e.: initial or trigger) driver of the investment. For material projects/programs, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment. Doing this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or program for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

The distributor must provide completed appendices 2-AA: Capital Projects Table and 2-AB: Capital Expenditure Summary Table along with the following information about a distributor's capital expenditures.

The capital expenditure summary provides a snapshot of InnPower's capital and System O&M expenditures over the 2017–2028 DSP period. For summary purposes, the entire capital costs of individual projects and programs have been allocated to one of the four OEB investment categories based on the primary driver for the investment:

1. System Access.
2. System Renewal.
3. System Service.
4. General Plant.

The breakdown of plan versus actuals over the historical period, broken down by category, is provided in Table 5.4-1, and the forecast costs broken down by category are provided in Table 5.4-2.

Table 5.4-1: Historical and Bridge Year Capital Expenditures and System O&M

Category	Historical																		Bridge		
	2017			2018			2019			2020			2021			2022			2023		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.[1]	Act.	Var.	Plan.[2]	Act[3]	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access																					
Gross Capital	3,509	1,523	(57)	13,778	2,096	(85)	11,682	5,169	(56)	12,103	7,640	(37)	13,192	8,945	(32)	X	3,856	X	25,415	-	-
Capital Contributions	(1,869)	(980)	(48)	(11,826)	(1,360)	(89)	(9,928)	(3,865)	(61)	(10,450)	(5,774)	(45)	(11,129)	(7,191)	(35)	X	(3,278)	X	(23,920)	-	-
Net Capital	1,640	543	(67)	1,951	736	(62)	1,754	1,304	(26)	1,653	1,866	13	2,063	1,754	(15)	X	578	X	1,494	-	-
System Renewal																					
Gross Capital	1,348	2,553	89	1,142	1,908	67	3,326	1,495	(55)	2,862	2,006	(30)	2,577	1,798	(30)	X	8,042	X	9,994	-	-
Capital Contributions	0	0	0	0	0	0	0	(111)	100	0	(156)	100	0	(174)	100	X	(5,719)	X	(8,250)	-	-
Net Capital	1,348	2,553	89	1,142	1,908	67	3,326	1,385	(58)	2,862	1,851	(35)	2,577	1,624	(37)	X	2,324	X	1,744	-	-
System Service																					
Gross Capital	248	21	(92)	660	276	(58)	393	2,273	478	534	2,737	413	422	2,412	472	X	503	X	11,967	-	-
Capital Contributions	0	0	0	0	0	0	0	(2,457)	100	0	(2,607)	100	0	(17)	100	X	0	X	(4,875)	-	-
Net Capital	248	21	(92)	660	276	(58)	393	(184)	(147)	534	130	(76)	422	2,396	468	X	503	X	7,091	-	-
General Plant																					
Gross Capital	1,168	363	(69)	1,423	1,147	(19)	962	273	(72)	745	649	(13)	706	1,227	74	X	970	X	1,155	-	-
Capital Contributions	0	0	0	0	0	0	0	0	0	0	(9)	100	0	0	0	X	0	X	(0)	-	-
Net Capital	1,168	363	(69)	1,423	1,147	(19)	962	273	(72)	745	640	(14)	706	1,227	74	X	970	X	1,155	-	-
Total (Gross)	6,274	4,460	(41)	17,003	5,426	(213)	16,362	9,210	(78)	16,244	13,032	(25)	16,897	14,382	(17)	X	13,372	X	48,530	-	-
Total Capital Contributions	(1,869)	(980)	(91)	(11,826)	(1,360)	(770)	(9,928)	(6,433)	(54)	(10,450)	(8,545)	(22)	(11,129)	(7,382)	(51)	X	(8,996)	X	(37,046)	-	-
Total (Net)	4,405	3,481	(27)	5,176	4,067	(27)	6,434	2,778	(132)	5,794	4,487	(29)	5,768	7,000	18	X	4,376	X	11,485	-	-
System O&M	2,179	2,217	2	2,245	2,029	(11)	2,246	1,966	(14)	2,246	1,867	(20)	2,246	2,598	14	X	2,318	X	2,622	-	-

[1] 2022 planned values not available since the previous DSP was planned and approved for 2017–2021 and the CoS Application (originally to be submitted in 2022) was deferred by a year. (These entries were left blank and populated with "X"). Consequently, 2022 Variance has been left blank and populated with "X."

[2] The planned System Service spend in 2023 includes InnPower's capital contributions towards the BATU project and costs relating to InnPower's new TS Project. The TS Project capital spending in 2023 will remain in WIP and will be addressed in InnPower's next rebasing application once the TS Project is energized.

[3] 2023 actuals were not available at the time of DSP submission.

Table 5.4-2: Forecast Capital Expenditures and System O&M

Category	Forecast				
	2024	2025	2026	2027	2028
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital	23,410	17,381	9,584	8,624	8,875
Capital Contributions	(21,160)	(15,179)	(7,669)	(6,997)	(7,247)
Net Capital	2,250	2,203	1,915	1,626	1,629
System Renewal					
Gross Capital	1,429	1,593	1,633	1,674	1,716
Capital Contributions	(0)	(0)	(0)	(0)	(0)
Net Capital	1,429	1,593	1,633	1,674	1,716
System Service [1]					
Gross Capital	7,519	9,374	4,902	5,207	32,417
Capital Contributions	(3,100)	(4,720)	(0)	(0)	(0)
Net Capital	4,419	4,654	4,902	5,207	32,417
General Plant					
Gross Capital	1,022	730	803	821	1,035
Capital Contributions	(0)	(0)	(0)	(0)	(0)
Net Capital	1,022	730	803	821	1,035
Total (Gross)	**33,380**	**29,078**	**16,922**	**16,326**	**44,043**
Total Capital Contributions	**(24,260)**	**(19,898)**	**(7,669)**	**(6,997)**	**(7,247)**
Total (net)	**9,120**	**9,180**	**9,253**	**9,328**	**36,797**
System O&M	3,091	3,307	3,406	3,508	3,614

[1] The System Service budget over the forecast period includes InnPower's capital contributions towards the BATU project and costs relating to InnPower's new TS Project. The TS Project capital spending over the 2024–2028 period will remain in WIP and will be addressed in InnPower's next rebasing application once the TS Project is energized.

5.4.1.1 Plan Versus Actual Variances for the Historical Period

The distributor must provide an analysis of a distributor's capital expenditure performance for the DSP's historical period. This should include an explanation of variances by investment or category that exceed +/- 10%. This includes actuals versus the OEB-approved/planned amounts for the applicant's last OEB-approved Cost of Service or Custom IR application and DSP (the variance analysis should also include variances in planned and actual volume of work completed). A distributor should particularly explain variances in a given year that are much higher or lower than the historical trend.

Comparing the historical DSP costs and the actual and bridge expenditures, illustrates the adjustments InnPower had to make—responding to changes in customer needs, changing work scope, and other work constrains, such as weather or work restrictions.

Assessing and understanding variances is an important step for InnPower to promote continuous improvements in its estimation and budgeting process. Explanations for any significant variances that exceed the smallest of either +/- 10% or +/- $73,000 (i.e.: InnPower's materiality threshold), are explained in the following subsections.

InnPower has not historically tracked its planned versus actual volumes of work completed. As a result, this level of detail is not provided in the following subsections. In order to comply with the OEB's updated filing requirements, InnPower will begin tracking the planned and actual volumes of work completed going forward.

5.4.1.1.1 System Access

System Access projects are customer-driven and are not contollable. They are budgeted based on a rolling five-year historical average. System Access expenditures can be categorized into smaller categories such as road relocations, subdivision connections and primary and secondary service requests. No sub-category can be planned for with a high degree of accuracy; however, InnPower attempts to minimize the variances with proactive engagements with developers, county, municipality, road authorities, and customers.

2017 Budget Variance: (67%)

Overall, System Access projects actual spending was lower than budgeted in 2017 due to several projects being deferred. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-3.

Table 5.4-3: System Access: 2017 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SA07 Intersection Widening IBR and 5 Sideroad	415	-	- 415	-100%	Non-discretionary project delayed to 2020/2021 due to timelines adjusted by the County of Simcoe. Some of this work dovetailed into expansion works for the Salem development lands and the project was completed in 2021. Project was still completed as per last DSP plans but with a different timeline out of the control of InnPower.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SA06 City Road Widening and Intersect Widening IBR and Yonge Street	272	-	- 272	-100%	Non-discretionary project delayed to 2018 due to timelines adjusted by the County of Simcoe. Project was still completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2019SA20 Yonge Street Between Lockhart and Mapleview Drive—Hewitt	168	-	- 168	-100%	Non-discretionary project delayed to 2019 due to timelines associated with the expansion works for the Hewitt development lands. Project was still completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2017SA04 Base 4	128	-	- 128	-100%	This project included all subdivision expansions in InnPower service territory. These subdivisions are nondiscretionary, and the timelines are driven by the developers and the execution of the Offer to Connect.
IPC2019SA25 Essa Road from 10th Line (McKay) to Salem Road	127	-	- 127	-100%	Non-discretionary project delayed to 2024 due to timelines associated with the expansion works for the Salem development lands. Project will still be completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2020SA31 Lockhart Road from Yonge Street to 10th Sideroad—Hewitt (Stringing Only)	124	-	- 124	-100%	Non-discretionary project delayed to 2021 due to timelines associated with the expansion works for the Hewitt development lands. Project was still completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2019SA22 9th Line From Industrial PK to 5th SRH Line from Industrial PK TO 5th SR	80	-	80	-100%	IPC2019SA22 was deferred to 2019/2020 as a result of a pending funding agreement. Non-discretionary project delayed to 2025 due to timelines associated with the expansion works for the Salem development lands. Project will still be completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2017SA02 Base 2	23	108	85	374%	Non-discretionary project driven by the County of Simcoe for road related relocations. While InnPower has regular discussion with Road Authorities, this project timeline was advanced earlier than expected.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
Meters Metering	-	129	129	Undefined	This project accounts for the meters purchased by InnPower to accommodate additional load growth.

2018 Budget Variance: (62%)

Overall, System Access projects actual spending was lower than budgeted in 2018 due to changes in project planning, including the advancement and delay of non-discretionary projects of which timelines were beyond InnPower's control. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-4.

Table 5.4-4: System Access: 2018 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2018SA04 Base 4	1,094	33	- 1,062	-97%	This project included all subdivision expansions in InnPower service territory. These subdivisions are non-discretionary, and the timelines are driven by the developers and the execution of the Offer to Connect.
IPC2019SA10 IBR Widening—Yonge St to 20th Sideroad	471	-	- 471	-100%	Non-discretionary project delayed to 2019 due to timelines adjusted by the County of Simcoe. Project was still completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2018SA05 Metering	270	70	200	-74%	InnPower delayed suite metering project due to the developer rescheduling project close-out dates.
IPC2017SA02 BASE 2	26	500	475	1840%	Non-discretionary project driven by the County of Simcoe for road related relocations. While InnPower has regular discussion with Road Authorities, this project timeline was advanced earlier than expected. This included the completion of IPC2017SA06 from 2017.
IPC2017SA01 Capital Trouble Calls—Base 1	123	-	123	-100%	InnPower spent this budget in a newly created project in 2018 called IPC2018SR01. The budget is primarily used for capital trouble calls, compliance issues and immediate safety related concerns which are generally unplanned in nature.

2019 Budget Variance: (26%)

Overall, System Access projects actual spending was lower than budgeted in 2019 due to non-discretionary projects being delayed or pushed by third parties. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-5.

Table 5.4-5: System Access: 2019 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SA04 Base 4	1,094	-	-1,094	-100%	This project included all subdivision expansions in InnPower service territory. These subdivisions are non-discretionary, and the timelines are driven by the developers and the execution of the Offer to Connect.
IPC2017SA05 Metering	250	-	-250	-100%	InnPower budgeted this project in 2017 as part of a larger project but was deferred by the developer until 2019/2020.
IPC2019SA03 New Services (L, RPO, DG)	-	-76	-76	Undefined	Non-discretionary projects driven by customer including layouts, in-fill lots and third-party driven projects (e.g.: Communications). The increased costs were due to InnPower upgrading infrastructure within the vicinity of customer-initiated work which required replacement at the same time to achieve efficiencies.
IPC2019SA20 Yonge Street between Lockhart and Mapleview Drive—Hewitt	-	134	134	Undefined	Non-discretionary project completed in 2019 due to timelines associated with the expansion works for the Hewitt development lands. Project was still completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2018SA02 Base 2	-	135	135	Undefined	Non-discretionary project driven by the County of Simcoe for road related relocations. While InnPower has regular discussion with Road Authorities, this project timeline was advanced earlier than expected.
IPC2019SA09 HWY 89/400 MTO Bridge Replacement—MTO	-	911	911	Undefined	Non-discretionary project driven by the MTO for road related relocations including the shifting of the overpass bridge. While InnPower has regular discussion with Road Authorities, this project timeline was advanced earlier than expected.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SA01 Capital Trouble Calls—Base 1	135	-	-135	-100%	InnPower spent this budget in a newly created project in 2019 called IPC2019SA01. While the scope and the type of work completed fall under the same category, this project was renamed to align with the year of expenditures. This budget is primarily used for capital trouble calls, compliance issues, and immediate safety related concerns which are generally unplanned in nature.
IPC2019SA01 Small Capital Jobs and Capital Trouble Calls	-	110	110	Undefined	InnPower used the original project IPC2017SA01 to align with budgeted amount. While the scope and the type of work completed fall under the same category this project was renamed to align with the year of expenditures. This budget is primarily used for capital trouble calls, compliance issues and immediate safety related concerns that are generally unplanned in nature.

2020 Budget Variance: 13%

Overall, System Access projects actual spending was higher than budgeted in 2020 due to cost increases and the completion of a project that was deferred from 2018. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-6.

Table 5.4-6: System Access: 2020 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SA04 Base 4	1,094	-	-1,094	-100%	This project included all subdivision expansions in InnPower service territory. These subdivisions are non-discretionary, and the timelines are driven by the developers and the execution of the Offer to Connect. In 2020, InnPower started to create individual projects for each subdivision due to the large number of subdivisions coming online. The budget for this project was re-allocated to IPC2019SD152 and IPC2019SD167.
IPC2017SA05 Metering	250	-	-250	-100%	InnPower budgeted this project in 2017 as part of a larger project but was deferred by the developer until 2019/2020.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2020SA05 Metering—Residential, Commercial, Wholesale Metering	-	110	110	Undefined	InnPower budgeted this project in 2017 as part of a larger project but was deferred by the developer until 2019/2020.
IPC2019SD152 Sleeping Lion	-	188	188	Undefined	This project includes the Sleeping Lion subdivision expansions in InnPower service territory. These subdivisions are non-discretionary, and the timelines are driven by the developers and the execution of the Offer to Connect. In 2020, InnPower started to create individual projects for each subdivision due to the large number of subdivisions coming online. These budgets were previously budgeted under IPC2017SA04 but included these subdivisions scope originally.
IPC2019SD167 SLEEPING LION PHASE 2	-	189	189	Undefined	This project includes the Sleeping Lion subdivision expansions in InnPower service territory. These subdivisions are non-discretionary, and the timelines are driven by the developers and the execution of the Offer to Connect. In 2020, InnPower started to create individual projects for each subdivision due to the large number of subdivisions coming online. This expenditure was previously budgeted under IPC2017SA04.
Meters Meters	-	578	578	Undefined	InnPower purchased meters to accommodate additional load growth.
IPC2019SA10 IBR Widening Yonge St to 20th SDRD	-	766	766	Undefined	Non-discretionary project driven by the County of Simcoe for road related relocations including the shifting of the overpass bridge. While InnPower has regular discussion with Road Authorities, this project timeline was delayed from 2019.
IPC2017SA01 Base 1	148	-	148	-100%	InnPower spent this budget in a newly created project in 2020 called IPC2020SA01. While the scope and the type of work completed fall under the same category this project was renamed to align with the year of expenditures. This budget is primarily used for capital trouble calls, compliance issues and immediate safety related concerns which are generally unplanned in nature.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2019SA01 Small Capital Jobs and Capital Trouble Calls	-	99	99	Undefined	InnPower used the original project IPC2017SA01 to align with budgeted amount. While the scope and the type of work completed fall under the same category this project was renamed to align with the year of expenditures. These specific works were started in 2019 but completed in 2020. This budget is primarily used for capital trouble calls, compliance issues and immediate safety related concerns which are generally unplanned in nature.
IPC2020SA01 Small Capital Jobs and Capital Trouble Calls	-	208	208	Undefined	InnPower used the original project IPC2017SA01 to align with budgeted amount. While the scope and the type of work completed fall under the same category this project was renamed to align with the year of expenditures. This budget is primarily used for capital trouble calls, compliance issues and immediate safety related concerns which are generally unplanned in nature.

2021 Budget Variance: (15%)

Overall, System Access projects actual spending was lower than budgeted in 2021 due to non-discretionary projects being delayed or pushed by third parties. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-7.

Table 5.4-7: System Access: 2021 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SA04 Base 4	1,094	-	-1,094	-100%	This project included all subdivision expansions in InnPower service territory. These subdivisions are non-discretionary, and the timelines are driven by the developers and the execution of the Offer to Connect. In 2020, InnPower started to create individual projects for each subdivision due to the large number of subdivisions coming online. This budget was re-allocated to IPC2019SD174.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2020SA35 9th Line From County RD 27 (ESSA) TO 5th LINE (Veterans)	471	-	- 471	-100%	Non-discretionary project delayed to 2025 due to timelines associated with the expansion works for the Salem development lands. Project will still be completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2017SA05 Metering	250	-	-250	-100%	InnPower budgeted this project in 2017 as part of a larger project but was deferred by the developer until 2019/2020.
IPC2018SA02 Base 2	-	88	88	Undefined	Non-discretionary project driven by the Town of Innisfil for road related relocations. While InnPower has regular discussion with Road Authorities, this project timeline was advanced earlier than expected.
IPC2020SA05 Metering—Residential, Commercial, Wholesale Metering	-	128	128	Undefined	InnPower budgeted this project in 2017 as part of a larger project but was deferred by the developer until 2019/2020.
IPC2020SA03 New Services (L, RPO, DG)	-	134	134	Undefined	Non-discretionary projects driven by customer including layouts, in-fill lots and third-party driven projects (e.g.: Communications). The increased costs were due to InnPower upgrading infrastructure within the vicinity which required replacement at the same time to achieve efficiencies.
IPC2019SD174 Bear Creek Ridge—Salem	-	357	357	Undefined	This project includes the Bear Creek subdivision expansions in InnPower service territory. These subdivisions are non-discretionary, and the timelines are driven by the developers and the execution of the Offer to Connect. In 2020, InnPower started to create individual projects for each subdivision due to the large number of subdivisions coming online. These budgets were previously budgeted under IPC2017SA04 but included these subdivisions scope originally.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2020SA38 IBR & HWY 400 Bridge Reconstruction—MTO	-	389	389	Undefined	Non-discretionary project driven by the MTO for road related relocations including the shifting of the overpass bridge. This project was started in 2020 and was completed in 2021. While InnPower has regular discussion with Road Authorities, this project timeline fluctuated due to required highways closures and coordination with road construction.
IPC2019SA06 IBR & 5th SR Intersection Widening	-	553	553	Undefined	Non-discretionary project delayed from 2017 due to timelines adjusted by the County of Simcoe as they were the drivers of this project. Some of this work dovetailed into expansion works for the Salem development lands and the project was completed in 2021. Project was still completed as per last DSP plans but with a different timeline out of the control of InnPower.
IPC2017SA01 Base 1	163	-	-163	-100%	InnPower spent this budget in a newly created project in 2021 called IPC2020SA01. While the scope and the type of work completed fall under the same category this project was renamed to align with the year of expenditures. This budget is primarily used for capital trouble calls, compliance issues and immediate safety related concerns which are generally unplanned in nature.
IPC2020SA01 Small Capital Jobs and Capital Trouble Calls	-	432	432	Undefined	InnPower used the original project IPC2017SA01. While the scope and the type of work completed fall under the same category this project was renamed to align with the year of expenditures. This was a combination of work started in 2020 and 2021 with all of it being completed in 2021. This budget is primarily used for capital trouble calls, compliance issues and immediate safety related concerns which are generally unplanned in nature.

2022 Budget Variance (N/A):

Since the COS Application was deferred by a year, OEB-approved planned amounts for 2022 are not available. Hence, the variance analysis for 2022 could not be produced.

5.4.1.1.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of station and distribution system assets. They are driven by the overall reliability, safety, and sustainment of the distribution system. These are discretionary investments that are informed by InnPower AM process.

2017 Budget Variance: 89%

Overall, System Renewal projects actual spending was higher than budgeted in 2017 due to a project's timeline being condensed and due to load growth system requiring expansion projects along with rehabilitation and upgrades on the existing system. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-8.

Table 5.4-8: System Renewal: 2017 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SR09 Ewart Street Rebuild—Phased Approach	105	277	172	164%	Rebuild was originally planned to be spread out over five years, but because of the cost to remobilize, it was more economical to condense this project.
IPC2017SR11 Reliability Rebuild Subtransmission	246	422	177	72%	Due to some deferred projects in System Access and General Plant, InnPower completed multiple jobs to replace end-of-life assets supporting the subtransmission (44kV system) including multiple individual pole replacements and two projects along 5th Sideroad between Line 3 and Line 5 to improve reliability.
IPC2017SR08 Station Rehab	104	14	-90	-87%	Due to load growth forecasted in 2017, InnPower deferred this investment to future years. This was to enable the finalization of the expansion projects with the developers on non-contestable recoverable jobs.

2018 Budget Variance: 67%

Overall, System Renewal projects actual spending was higher than budgeted in 2018 due to a project being partially cancelled, offset by additional projects being added s. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-9.

Table 5.4-9: System Renewal: 2018 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SR10 Overloaded Transformers	110	-	-110	-100%	With InnPower having multiple expansion and rehab projects ongoing, the decision was made to use this budget in those projects and defer this project further out.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2018SR09 Mapleview Drive Pole Line Rebuild East of 25th SDRD	-	117	117	Undefined	InnPower delayed this project until it could finalize the load demand with the developers.
IPC2018SR02 Substandard Transformer Rehab	30	162	132	441%	InnPower identified substandard assets in its system, which could cause safety and reliability issues. Therefore, the budget from project IPC2017SR10 was spent in 2018 to clean up majority of substandard assets.
IPC2018SR04 infrastructure replacements and Betterments	158	392	234	148%	InnPower was able to complete additional work on this project as a result of time availability. Some of the incomplete work from 2017 and some of the planned work for 2019 was assigned to this year. This work included the replacement of assets as a result of InnPower's inspection program as well as efficiencies gained during customer-driven work.
IPC2018SR01 Base 1	-	631	631	Undefined	This budget is primarily used for capital trouble calls, compliance issues, and immediate safety-related concerns which are generally unplanned in nature. These non-discretionary projects used the placeholder budget of IPC2017SA01 which was based on historical values.
IPC2018SR08 Station Rehab	110	23	-87	-79%	The budget for this project was re-allocated towards other station rehab projects within System Renewal.

2019 Budget Variance: (58%)

Overall, System Renewal projects actual spending was lower than budgeted in 2019 due to projects being deferred or cancelled. . Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.410.

Table 5.4-10: System Renewal: 2019 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2018SR12 Subtrans Lockhart E/O Stroud DS	294	-	-294	-100%	This project budget was re-allocated towards IPCSA06.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2020SR12 Sandy Cove Acres North Side of Lockhart Rebuild—Phase 1 OF 2	835	-	-835	-100%	InnPower deferred this project to accommodate higher priority projects.
IPC2017SR11 Reliability Rebuild Subtransmission	550	-	-550	-100%	InnPower deferred this project to accommodate higher priority projects identified at the time (i.e.: to find efficiencies with the developments that were in initial discussions).
400 Corridor Voltage Conversion and Servicing	250	-	-250	-100%	InnPower deferred this project to accommodate higher priority projects identified at the time (i.e.: to find efficiencies with the developments that were in initial discussions).
Alcona South Voltage Conversion	200	-	-200	-100%	InnPower deferred this project to accommodate higher priority projects identified at the time (i.e.: to find efficiencies with the developments that were in initial discussions).
IPC2019SR06 Everton and Lakeshore Backlot Conversion	155	-	-155	-100%	InnPower deferred this project to accommodate higher priority projects identified at the time
IPC2018SR10 Overloaded Transformers	121	31	-90	-75%	InnPower deferred this project to accommodate higher priority projects. With InnPower expending more on the substandard assets, InnPower deferred this project to future years.
IPC2019SR02 Overhead Substandard Transformer Rehab	-	87	87	Undefined	This project was merged with IPC2018SR01 and spent in a full amount.
IPC2019SR07 CooksTown Area Dist—Victoria St North Side (HWY 27 to Royal Oak)	-	115	115	Undefined	This project was budgeted under the general IPC2018SR04 and spent in the specific Cookstown Area.
IPC2018SR01 Base 1	129	6	123	95%	This budget is primarily used for capital trouble calls, compliance issues and immediate safety-related concerns which are generally unplanned in nature. These non-discretionary projects used the placeholder budget of IPC2017SA01 which was based on historical values.
IPC2018SR04	166	8	158	95%	InnPower deferred this project to accommodate higher priority projects.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
Infrastructure Replacements and Betterments					Due some assets identified through inspection as end-of-life, this budget was re-allocated to IPC2019SR07.
IPC2018SR08 Station Rehab	-	195	195	Undefined	This project is part of station rehab required based on results from ACAs, inspections, and testing. InnPower identified this project as a high priority and used the budget from IPC2019SR11.

2020 Budget Variance: (35%)

Overall, System Renewal projects actual spending was lower than budgeted in 2020 due to several project deferrals and cancelations. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-11.

Table 5.4-11: System Renewal: 2020 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2018SR12 Reliability Rebuild—Subtrans Lockhart E/O Stroud DS	203	-	-203	-100%	InnPower pushed the timelines of this project to 2023 to align with expansion developments in the area. This project also ties into the Metrolinx Electrification relocation project on Lockhart Road so the decision was made to defer this InnPower driven project to gain efficiency and to accommodate third-party requests.
IPC2020SR12 Sandy Cove Acres North Side of Lockhart Rebuild—Phase 1 of 2	520	-	-520	-100%	This project was pushed until further notice due to the limited number of cable failures in this area. While this section of underground cable is under constant evaluation, InnPower has not seen failures that justify this replacement over some of the other assets that are in poorer condition based on inspection and ACA results.
400 Corridor Voltage Conversion and Servicing	263	-	-263	-100%	InnPower deferred this project to accommodate higher priority projects (i.e.: to find efficiencies with the developments that were in initial discussions).
AIPC2017SR11 Reliability Rebuild Subtransmission	225	-	-225	-100%	InnPower deferred this project to accommodate higher priority projects. Due to some assets identified through inspection as

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
					end-of-life, this budget was re-allocated to IPC2020SR11
Alcona South Voltage Conversion	210	-	-210	-100%	InnPower deferred this project to accommodate higher priority projects. Hence, this project was deferred to future years to find efficiencies with the developments that were in initial discussions.
IPC2018SR14 Reliability Rebuild—Dist Cookstown Area PH Approach	201	-	-201	-100%	InnPower deferred this project to accommodate higher priority projects. Due to some assets identified through inspection as end-of-life, this budget was re-allocated to IPC2020SR01.
IPC2018SR04 Infrastructure Replacements and Betterments	174	-	-174	-100%	InnPower deferred this project to accommodate higher priority projects. Due to some assets identified through inspection as end of life, this budget was re-allocated to IPC2020SR07.
IPC2018SR03 Pole Replacement Program	164	-	-164	-100%	This project had the funds allocated to the same project scope with an updated name in IPC2020SR03.
IPC2018SR01 Base 1	135	-	-135	-100%	This budget is primarily used for capital trouble calls, compliance issues and immediate safety-related concerns, which are generally unplanned in nature. These non-discretionary projects used as the placeholder budget of IPC2017SA01 which was based on historical values.
IPC2018SR10 Overloaded Transformers	133	-	-133	-100%	InnPower did not encounter any overloaded transformers in 2020, so the budget was re-allocated towards IPC2019SA01 and IPC2020SA01.
IPC2020SR03 Pole Replacement Program (VAR LOC) 4 YR Cycle	-	249	249	Undefined	This project had the funds allocated from IPC2018SR03.
IPC2020SR01 Prior Years Cleanup and Unbudgeted SR Projects	-	335	335	Undefined	This project had the funds allocated from IPC2018SR14 and IPC2018SR04, which were deferred.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2020SR11 Pole Replacement—Alcona area—St. Johns from 7th Line to Nantyr	-	359	359	Undefined	Due to safety issues identified during recent inspections and the need to accommodate growth in the area, InnPower added this project using re-allocated funds from IPC2018SR11.
IPC2018SR08 Station Rehab	242	-	-242	-100%	This project was moved to IPC2019SS13 to upgrade/rehaul Innisfil DS due to poor condition of station assets.

2021 Budget Variance: (37%)

Overall, System Renewal projects actual spending was lower than budgeted in 2021 due to several deferrals and cancelations. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.412.

Table 5.4-12: System Renewal: 2021 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2018SR12 Reliability Rebuild—Subtrans Lockhart E/O Stroud DS	213	-	-213	-100%	InnPower pushed the timelines of this project to 2023 to align with expansion developments in the area. This project also ties into the Metrolinx Electrification relocation project on Lockhart Road, so the decision was made to defer this InnPower driven project to accommodate third-party requests and to gain efficiency.
IPC2020SR12 Sandy Cove Acres North Side of Lockhart Rebuild—Phase 1 of 2	400	-	-400	-100%	This project was pushed until further notice due to the limited number of cable failures in this area. While this section of underground cable is under constant evaluation, InnPower has not seen failures that justify this replacement over some of the other assets which scored lower based on inspection and ACA results.
400 Corridor Voltage Conversion and Servicing	276	-	-276	-100%	InnPower deferred this project to accommodate higher priority projects, i.e.: to find efficiencies with the developments that were in initial discussions.
IPC2017SR11 Reliability Rebuild Subtransmission	225	-	-225	-100%	InnPower deferred this project to accommodate higher priority projects, i.e.: to find efficiencies with the

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
					developments that were in initial discussions.
Alcona South Voltage Conversion	221	-	-221	-100%	InnPower deferred this project to accommodate higher priority projects, i.e.: to find efficiencies with the developments that were in initial discussions.
IPC2018SR04 Infrastructure Replacements and Betterments	183	-	-183	-100%	InnPower deferred this project to accommodate higher priority projects, i.e.: to find efficiencies with the developments that were in initial discussions. Funds were re-allocated to IPC2020SR01
IPC2018SR03 Pole Replacement Program	172	-	-172	-100%	This project had the funds allocated to the same project scope with an updated name in IPCSR03.
IPC2018SR14 Reliability Rebuild—Dist CooksTown Area PH Approach	156	-	-156	-100%	InnPower deferred this project to accommodate higher priority projects, i.e.: to find efficiencies with the developments that were in initial discussions. Funds were allocated for IPC2020SR11.
IPC2018SR01 Base 1	149	-	-149	-100%	InnPower deferred this project to accommodate higher priority projects, i.e.: to find efficiencies with the developments that were in initial discussions. Funds were allocated for IPC2020SA01.
IPC2018SR10 Overloaded Transformers	146	-	-146	-100%	This project had the funds allocated to the same project scope with an updated name in IPC2020SR10.
IPC2017SR09 Ewartewart Street Rebuild—Phased Approach Street Rebuild—Phased Approach	131	-	-131	-100%	InnPower deferred this project to accommodate higher priority projects, i.e.: to find efficiencies with the developments that were in initial discussions. Funds were allocated to IPCSR02.
IPCSR02 Transformer Replacement Program	-	122	122	Undefined	This project had the funds allocated from the same project scope in IPC2017SR09.
IPC2020SR11 Pole Replacement —Alcona Area St. Johns from 7th Line to Nantyr	-	133	133	Undefined	Due to safety issues identified during recent inspections and the need to accommodate growth in the area, InnPower added this project using re-allocated funds from IPC2018SR14. This

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
					was the completion of a job started in 2020.
IPCSR03 Pole Replacement Program	-	163	163	Undefined	This project had the funds allocated from the same project scope in IPC2018SR03.
IPC2020SR10 Transformer Rehab\ Replacements	-	169	169	Undefined	This project had the funds allocated from the same project scope in IPC2018SR10.
IPC2020SR01 Prior Years Cleanup and Unbudgeted Sr Projects	-	171	171	Undefined	This project was created for a few projects that were not completed in 2020 and carried over to 2021. This also included safety and compliance issues that needed to be completed in 2021.

2022 Budget Variance (N/A):

Since the CoS Application was deferred by a year, OEB-approved planned amounts for 2022 are not available. Hence, the variance analysis for 2022 could not be produced.

5.4.1.1.3 System Service

2017 Budget Variance: (92%)

Overall, System Service projects actual spending was lower than budgeted in 2017 due to costs to be transferred to another program. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-13.

Table 5.4-13: System Service: 2017 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SS03 Repoling Lockhart Rd Huronia Rd to Stroud DS	-	178	178	Undefined	The project was advanced to 2017 due to pole deterioration. The rebuild to replace end-of-life poles was upgraded to accommodate future load growth, particularly in the Hewitt lands and local load growth.
IPC2017SS02 Repoling BBP RD Friday Harbour DS to FH Deve Nth	-	703	703	Undefined	The project was advanced to 2017 due to pole deterioration. The rebuild to replace end-of-life poles was upgraded to gain efficiency and to accommodate future load growth, particularly with respect to the Friday Harbour development and local load growth.
IPC2018SS03 Sandy Cove DS Recloser Upgrade	125	-	-125	-100%	InnPower deferred this project to 2018 due to delay in supply chain.

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SS04 Sandy Cove DS Automation	-	-	-	Undefined	This project was merged with IPC2018SS03, and the budget was spent in 2018.

2018 Budget Variance: (58%)

Overall, System Service projects actual spending was lower than budgeted in 2018 due to a few deferrals and the completion of a project that was deferred from 2017. Key project-level variances and justifications that contributed to this overall variance are summarized in Table 5.4-14.

Table 5.4-14: System Service: 2018 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017SS01 Dist Scada Controlled Load Interrupting Gang Switch	79	-	-79	-100%	InnPower deferred this project to optimize efficiencies with incoming expansion developments.
IPC2018SS03 Sandy Cove DS Recloser Upgrade	-	253	253	Undefined	This project is from 2017 and the budget was spent in 2018. Budgets from both IPC2018SS03 and IPC2017SS04 were spent in 2018.
IPC2019SS09 Station Rehab—Friday Harbour DS Works (BBP, LB, SC)	550	-	-550	-100%	InnPower advanced this project due to system demand in 2017 and this budget was spent in IPC2017SS02.

2019 Budget Variance: (147%)

Overall, System Service projects actual spending was lower than budgeted in 2019 due to some deferrals and cancelations as well as the completion of some projects previously deferred. Key project-level variances and justifications that contributed to this overall variance are summarized in Table 5.4-15.

Table 5.4-15: System Service: 2019 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2019SS19 Purchase and Installation of a SCADA-Mate Switch	149	-	-149	-100%	InnPower started commissioning the existing switches as opposed to installing new switches for this year. This budget was spent in IPC2019SS07 and IPC2019SS02.
IPC2017SS01 Dist Scada Controlled Load	83	-	-83	-100%	InnPower deferred this project to accommodate higher priority projects. InnPower started commissioning the

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
Interrupting Gang Switch					existing switches as opposed to installing new switches for this year. This budget was spent in IPC2019SS07 and IPC2019SS02
IPC2019SS04 DS Oil Reinhibit Treatment	-	75	75	Undefined	InnPower deferred this project to the following years due to oil test report results. Instead, this budget was spent in IPC2019SS02 in 2019.
IPC2019SS02 Overhead Distribution Fault Current Indicators	-	643	-643	Undefined	InnPower used the unspent budget 2019 for this project to improve its reliability and minimize outage restoration duration.
IPC2019SS07 SCADA-Controlled Switch Commissioning	165	41	-124	-75%	InnPower started recommissioning its existing switches instead of installing new switches. For this reason, InnPower spent this budget in IPC2019SS02 to improve its reliability and minimize outage restoration duration.
IPC2019SS13 Innisfil Distribution Station Rehab	-	194	194	Undefined	Due to the very poor condition of the station, InnPower created this project to minimize the risk of failure to InnPower and to improve public safety. Also, budget from IPC2018SR08 has been used for this project.
IPC2019SS12 Station Rehab	-	195	195	Undefined	Due to the very poor condition of the Sandy Cove station, InnPower created this project to minimize the risk of failure to InnPower and to improve public safety.

2020 Budget Variance: (76%)

Overall, System Service projects actual spending was lower than budgeted in 2020 due to a deferral. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-16.

Table 5.4-16: System Service: 2020 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2019SS07 SCADA-Controlled Switch Commissioning	173	-	-173	-100%	Due to supply chain issues, InnPower was unable to receive required material to complete this project. This budget was deferred to IPC2020SS22.

2021 Budget Variance: 468%

Overall, System Service projects actual spending was higher than budgeted in 2021 due to the completion of several projects previously deferred. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-17.

Table 5.4-17: System Service: 2021 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2020SS22 Purchase and Installation OF SCADA-Mate Switch	-	106	106	Undefined	Due to supply chain issues in 2020, InnPower completed this project in 2021.
IPC2019SS07 SCADA-Controlled Switch Commissioning	182	59	-123	-68%	Due to material shortage and resource constraints, InnPower spent a portion of this budget in IPC2020SS22.
IPC2019SS14 Bob Duego DS— P&C Upgrade	-	106	106	Undefined	This project was required to upgrade the end-of-life assets in Bob Duego Protection and Control System.
IPC2019SS08 Sandy Cove Radio Repeater Site	-	166	166	Undefined	InnPower added another site to its network due to poor line of sites and reception in Northeast area of its service territory.
IPC2019SS09 Friday Harbour DS Works (BBP, LB, SC)	-	902	902	Undefined	This project is 100% recoverable and it was a growth-driven project to increase system capacity to accommodate the forecasted load.
IPC2019SS13 Innisfil Distribution Station Rehab	-	1,071	1,071	Undefined	This project involved the completion and energization of previous year projects due to the very poor condition of the station.

2022 Budget Variance (N/A):

Since the CoS Application was deferred by a year, OEB-approved planned amounts for 2022 are not available. Hence, the variance analysis for 2022 could not be produced.

5.4.1.1.4 General Plant

2017 Budget Variance: (69%)

Overall, General Plant projects actual spending was lower than budgeted in 2017 due to several project deferrals. Key project level variances and justifications that contributed to this overall variance are summarized in Table 5.4-18.

Table 5.4-18: General Plant: 2017 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017GP12 Replacement Double Bucket Truck 1993 Altec	374	-	- 374	-100%	Delayed the purchase of a new double bucket and purchased single bucket from Orangeville Hydro (see IPC2018GP14)
IPC2017GP06 Engineering IT	167	-	- 167	-100%	Quadra project was delayed due to customizations and resources.
IPC2017GP14 Tech Vehicles x 2	87	-	- 87	-100%	InnPower delayed the purchase of new vehicles and leased in 2019 (capital lease) and reduced the amount we leased by pooling vehicles.
IPC2017GP13 Fleet Vehicle Replacement 1— 2006 Ford 1/2 Ton	45	-	-45	-100%	InnPower delayed the purchase of new vehicles and leased in 2019 (capital lease) and reduced the amount we leased by pooling vehicles.

2018 Budget Variance: (19%)

Overall, General Plant projects actual spending was lower than budgeted in 2018 due to deferral of a project and an overestimation of IT hardware and software costs. Key project-level variances and justifications that contributed to this overall variance are summarized in Table 5.4-19.

Table 5.4-19: General Plant: 2018 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017GP14 Vehicle Purchase	182	-	-182	-100%	InnPower delayed the purchase of new vehicles and leased in 2019 (capital lease) and reduced the amount we leased by pooling vehicles.
IPC2018GP01 IT Hardware	150	46	-104	-70	InnPower purchased servers in 2017 and hence, the purchase of servers was not required in 2018, thereby explaining the negative variance.
IPC2018GP02 IT Software	95	14	-81	-85	InnPower delayed the purchase of IT software to 2019.
IPC2018GP04 Buildings and Fixtures	15	196	181	1,209%	InnPower agreed to pay for part of the renovation costs for Treasure Garden (daycare renting a portion of head office) as part of the lease agreement.

2019 Budget Variance (72%):

Overall, General Plant projects actual spending was lower than budgeted in 2019 due to overestimating costs and project deferrals. Key project-level variances and justifications that contributed to this overall variance are summarized in Table 5.4-20.

Table 5.4-20: General Plant: 2019 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
Tension Machines	200	-	- 200	-100%	Instead of purchasing the tension machines like originally planned, InnPower rented the machines on an as-needed basis. As a result, this project was canceled.
IPC2018GP06 Engineering IT	119	1	- 118	-99%	InnPower carried out this project under the project IPC2020GP06 in 2021.
IPC2019GP01 IT Hardware	150	45	- 105	-70%	InnPower delayed the purchase of IT hardware that was originally budgeted for 2018.
IPC2017GP14 Vehicle Purchase	96	-	- 96	-100%	InnPower decided to lease the vehicles instead of purchasing them and implemented a pooling of vehicles between employees to reduce the need for additional vehicles.

2020 Budget Variance: (14%):

Overall, General Plant projects actual spending was lower than budgeted in 2020 as a decision was made to lease and pool vehicles to save money. Key project-level variances and justifications that contributed to this overall variance are summarized in Table 5.4-21.

Table 5.4-21: General Plant: 2020 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2017GP14 Vehicle Purchase	101	-	-101	-100%	As a result of deferred new vehicle purchases, InnPower evaluated the option and ultimately proceeded with leasing vehicles to eliminate the purchase price and reduced the amount InnPower spent by pooling vehicles.

2021 Budget Variance: 74%

Overall, General Plant projects actual spending was higher than budgeted in 2021 due to several deferred and overbudgeted projects. Key project-level variances and justifications that contributed to this overall variance are summarized in Table 5.4-22.

Table 5.4-22: General Plant: 2021 Budget Variance Explanations

Project	Plan ($'000)	Actual ($'000)	Variance ($'000)	Variance (%)	Justification
IPC2020GP01 IT Hardware	150	25	-125	-83%	Due to uncertainty arising from COVID-19, InnPower continued the use of its assets that would otherwise be replaced in normal situations, thereby explaining the negative variance.
IPC2020GP06 Engineering IT	105	247	142	135%	Due to Covid-19 impact and lack of resources, this project was capitalized in 2021.
IPC2020GP18 Single Bucket Truck—Altec Buying Out	-	167	167	Undefined	InnPower rented an Altec bucket truck for several years to assist with the number of jobs required to be completed and due to supply chain issues, which meant there were no other trucks available for rent due to supply chain issues, InnPower evaluated the options and used the purchase credit during the rental to buyout the truck.
IPC2021GP19 WAJAX Radial Boom Derrick (RBD)	-	491	491	Undefined	InnPower purchased a new RBD for the replacement of an end-of-life RBD. This purchase was made through RFP evaluation.

2022 Budget Variance (N/A):

Since the CoS Application was deferred by a year, OEB-approved planned amounts for 2022 are not available. Hence, the variance analysis for 2022 could not be produced.

5.4.1.2 Forecast Expenditures

The distributor must provide an analysis of a distributor's capital expenditures for the DSP's forecast period.

The following table and figure summarize the planned capital expenditures, by investment category, over the forecast period. This is inclusive of the BATU project contributions and the TS Project costs (categorized as a System Service investment).

Table 5.4-23: Forecast Net Expenditures by Investment Category [Incl. BATU & TS Project]

Investment Category	Forecast ($ '000)					Total ($ '000)	Percent of Total
	2024	2025	2026	2027	2028		
System Access (net)	2,250	2,203	1,915	1,627	1,629	9,624	13.06%
System Renewal (net)	1,429	1,593	1,633	1,674	1,716	8,045	10.92%
System Service (net)	4,419	4,654	4,902	5,207	32,417	51,599	70.03%
General Plant (net)	1,022	730	803	821	1,035	4,411	5.99%
Total Capital (net)	**9,120**	**9,180**	**9,253**	**9,328**	**36,797**	**73,679**	**100.00%**

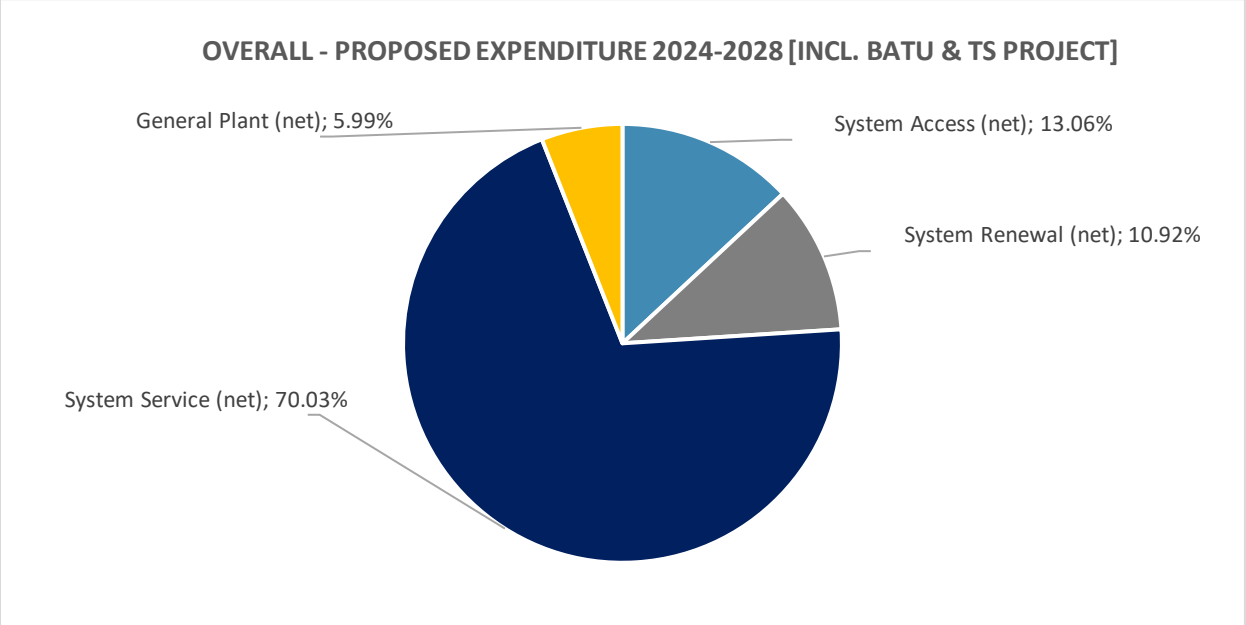


Figure 5.4-1: Forecast Net Expenditures by Investment Category [Incl. BATU & TS Project]

When including costs from both the BATU project contributions and new TS Project, System Service is the largest planned capital expenditure over the 2024–2028 forecast period representing 70.03% of overall spending, which is followed by System Access at 13.06%, System Renewal at 10.92%, and General Plant at 5.99%.

As noted above, the TS Project spending over the forecast period will sit in WIP and be addressed in InnPower's next rebasing application. A breakdown of the planned capital expenditures excluding the TS Project cost is shown in the table and figure below.

Table 5.4-24: Forecast Net Expenditures by Investment Category [Incl. BATU, Excl. TS Project]

Investment Category	Forecast ($'000)					Total ($ '000)	Percent of Total
	2024	2025	2026	2027	2028		
System Access (net)	2,250	2,203	1,915	1,627	1,629	9,624	22.83%
System Renewal (net)	1,429	1,593	1,633	1,674	1,716	8,045	19.09%
System Service (net)	4,419	4,654	4,902	5,207	883	20,065	47.61%
General Plant (net)	1,022	730	803	821	1,035	4,411	10.47%
Total Capital (net)	**9,120**	**9,180**	**9,253**	**9,328**	**5,263**	**42,144**	**100.00%**

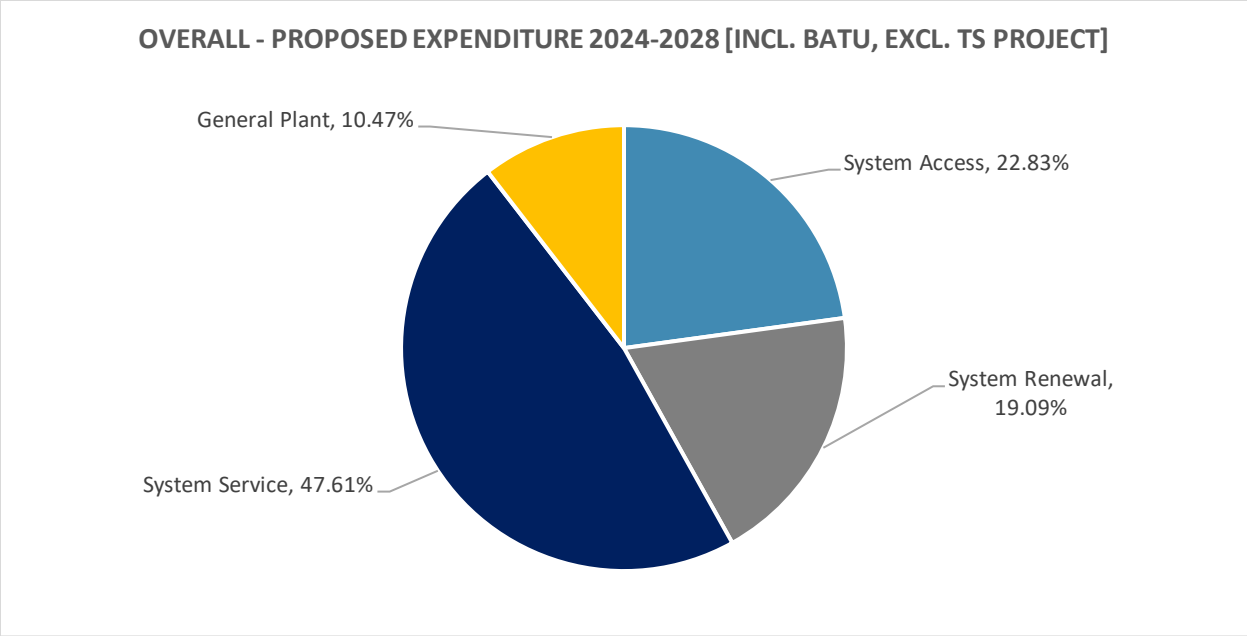


Figure 5.4-2: Forecast Net Expenditures by Investment Category [Incl. BATU, Excl. TS Project]

When excluding the TS Project costs, System Service remains as the largest planned capital expenditure category over the 2024–2028 forecast period; however, this is largely due to the BATU project contributions.

As previously noted, the BATU project was previously approved by the OEB in April 2020 and is currently being constructed by HONI. As part of this project, it was agreed that InnPower would make capital contribution installment payments to HONI for the incremental cost relative to the cost of the avoided sustainment work that HONI was originally planning to undertake on these facilities. As a result, this project is not considered to be part of InnPower's normal capital expenditures, and InnPower has excluded the BATU project costs from certain analyses in the following subsections to

provide the OEB and interveners with a more realistic picture of InnPower's expenditures. This also allows for a more representative comparison of the forecast expenditure compared to historical expenditures.

When excluding both the TS Project and BATU project costs, System Access becomes the largest planned capital expenditure over the 2024–2028 forecast period representing 37.50% of overall spending, followed by System Renewal at 31.35%, General Plant at 17.19%, and System Service at 13.97%, as shown in the following table and figure. Forecast costs by investment category are detailed further in the following sub-sections.

Table 5.4-25: Forecast Net Expenditures by Investment Category [Excl. BATU & TS Project]

Investment Category	Forecast ($'000)					Total ($ '000)	Percent of Total
	2024	2025	2026	2027	2028		
System Access (net)	2,250	2,203	1,915	1,627	1,629	9,624	37.50%
System Renewal (net)	1,429	1,593	1,633	1,674	1,716	8,045	31.35%
System Service (net)	299	534	782	1,087	883	3,585	13.97%
General Plant (net)	1,022	730	803	821	1,035	4,411	17.19%
Total Capital (net)	**5,000**	**5,060**	**5,133**	**5,209**	**5,263**	**25,665**	**100.00%**

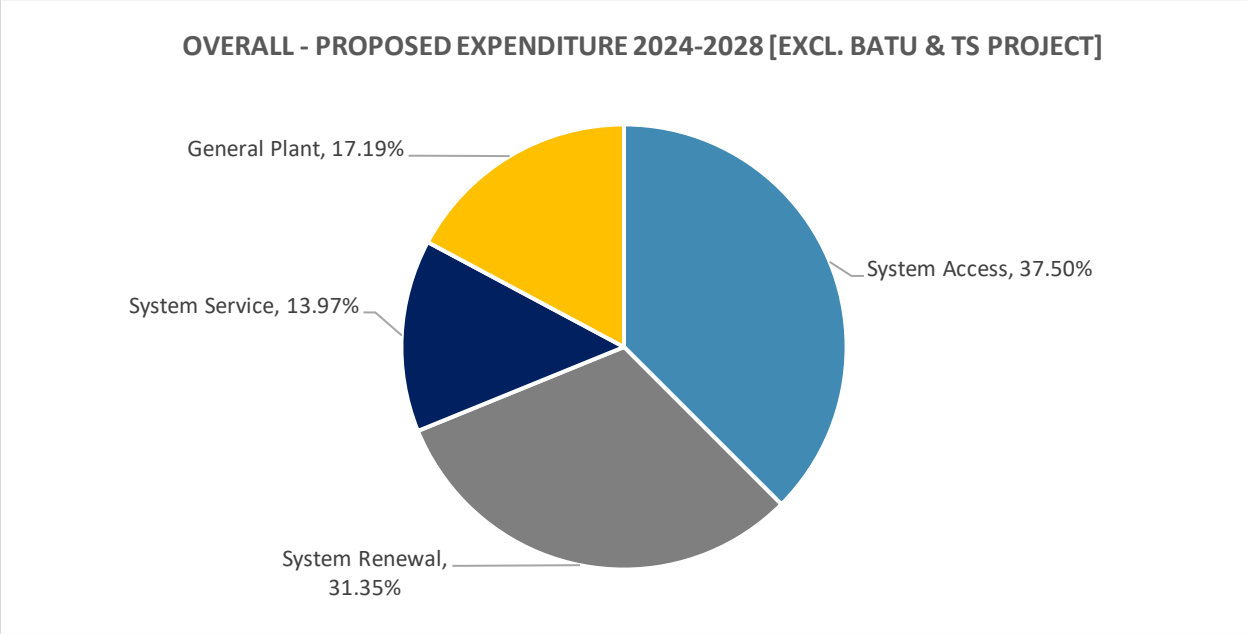


Figure 5.4-3: Forecast Net Expenditures by Investment Category [Excl. BATU & TS Project]

5.4.1.2.1 System Access

Expenditures within the System Access category are driven by external requirements such as servicing new customer loads and relocating distribution assets to suit road or municipal authorities. The timing of investments in this category are driven by the needs of external parties and are considered mandatory. Investments in System Access are captured in the table and figures below.

Table 5.4-26: Forecasted Net System Access Expenditures by Project ($'000)

Project	Forecast ($'000)					Total ($'000)	Percent of Total
	2024	2025	2026	2027	2028		
IPCSA – 100% Recoverable Material Narrative	0	0	0	0	0	0	0.00%
IPCSA – Subdivisions	663	971	812	1,088	1,077	4,611	47.92%
IPCSA02 – Road Authority	1,087	719	578	0	0	2,384	24.77%
IPCSA05 – Metering	500	513	525	538	552	2,628	27.31%
System Access (net)	**2,250**	**2,203**	**1,915**	**1,626**	**1,629**	**9,623**	**100.00%**

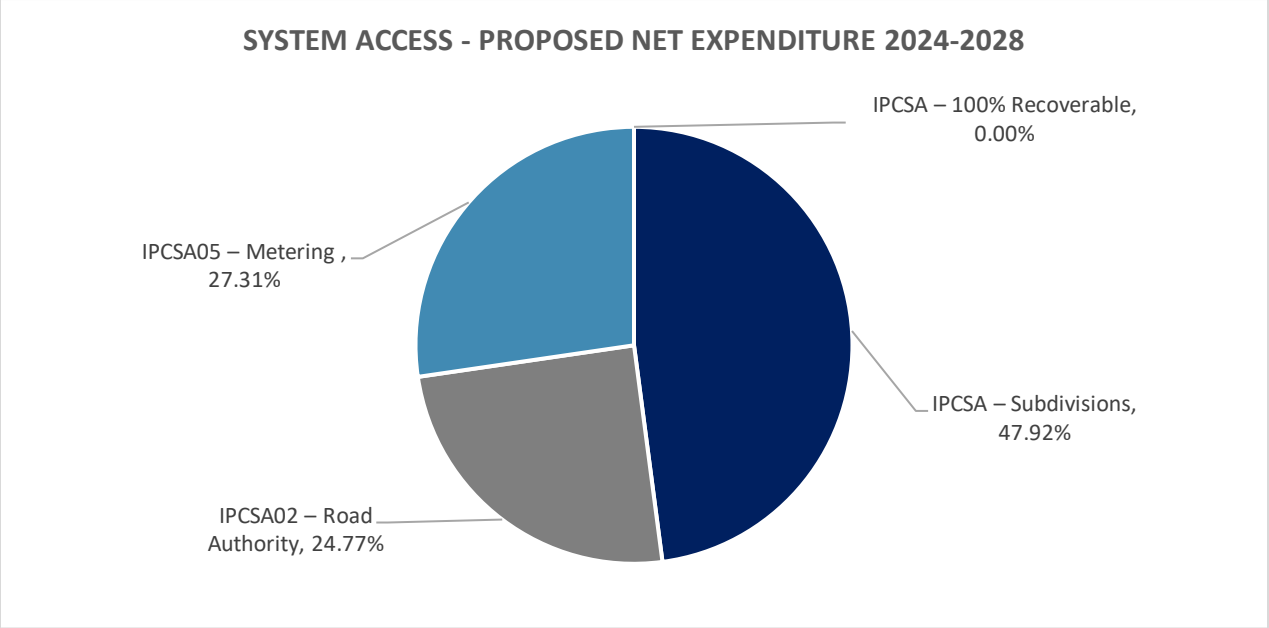


Figure 5.4-4: Forecasted Net System Access Expenditures by Project

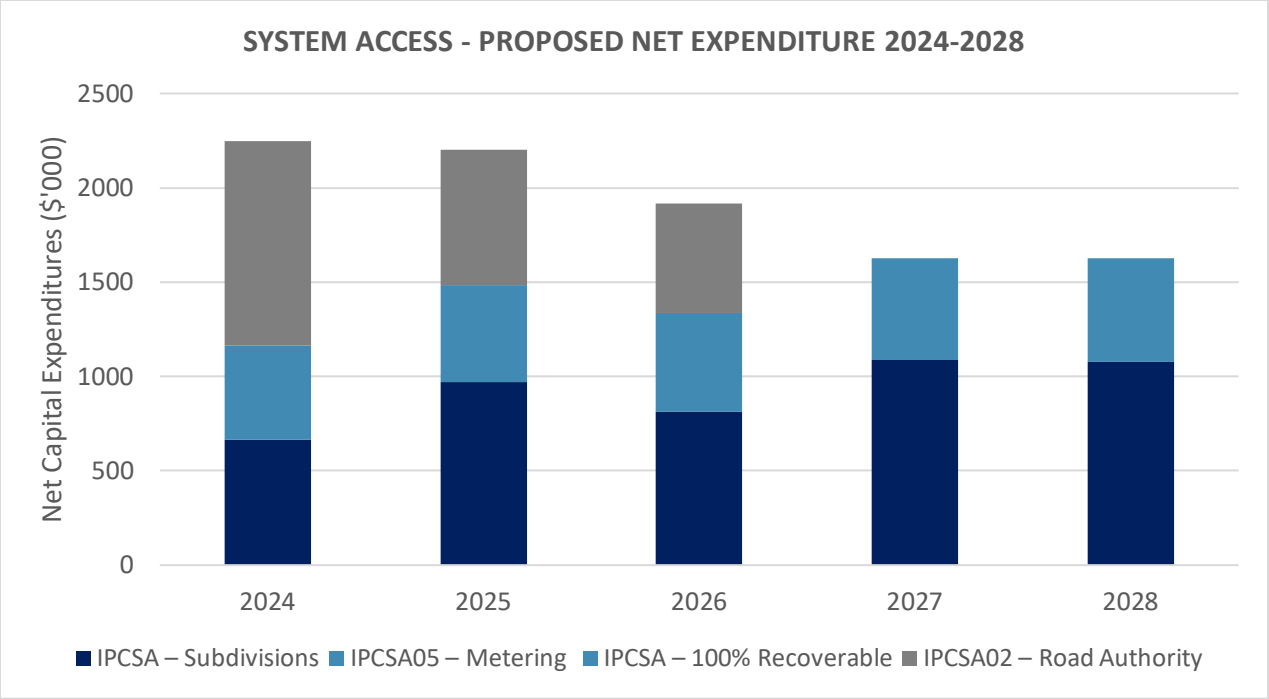


Figure 5.4-5: Forecasted Net System Access Expenditures by Project

When excluding the BATU and TS Project costs, net System Access is the largest planned capital expenditure over the 2024–2028 forecast period representing 37.50% of overall spending. The proposed expenditure level is estimated based on the historic spending levels and specific information available about planned projects at the time of preparation of this DSP.

Representing the largest portion (47.92%) of the expenditures within this category, subdivisions involve servicing lots to accommodate new subdivisions. A few of the larger subdivision initiatives happening in InnPower's service area over the forecast period include:

- **Sleeping Lion**, a subdivision development with an anticipated build-out of 5,000 homes on the 6th Line in Innisfil.
- **Friday Harbour,** a resort community within the area of Big Bay Point is a 600-acre site with a total build-out of 3,000 units over a ten-year period.
- **Hewitt Creek**, a subdivision development with an anticipated build-out of 900 homes on Mapleview Drive.
- **Barrie Lockhart Rd Gp, Sorbara**, a subdivision development with an anticipated build-out of 485 homes on Lockhart east of Huronia.
- **Bistro 6**, a subdivision development with an anticipated build-out of 788 homes on Mapleview drive east of Yonge.
- **Blue Sky/Honey Field Lands**, a subdivision development with an anticipated build-out of 890 homes on Big Bay Point Road and Mapleview drive East.

Metering, which represents the second largest driver within this category (27.31%), is related to the supply, installation, and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for all customers connected to InnPower's distribution system.

At 24.77%, Road Authority represents the next largest driver within this category. Road Authority works involve OH and/or UG lines relocations to accommodate road widening projects driven municipalities and the MTO. A few of the larger Road Authority projects happening in InnPower's service area over the forecast period include:

- **Innisfil Beach Road, 10th Sideroad to Yonge St.:** This relocation project, corresponding to Phase Two of the overall project, will accommodate the widening of Innisfil Beach Road from two lanes to five lanes due to increased traffic demand. Ongoing coordination for this project is not only with the County of Simcoe, but also Bell, Rogers, Enbridge, and InnServices to ensure all utilities are accommodated and transferred to align with project timelines.
- **Yonge St and 9th Line: Roundabout installation:** This project involves the relocation of InnPower assets to accommodate the replacement of an intersection with a roundabout.
- **Hewitt and Salem Projects:** Due to the large number of customers that will eventually reside in these areas, plans and coordination efforts have already begun to ensure that the new pole lines being built by InnPower to accommodate the growth also align with future road widenings to limit the amount of any potential relocations in the future.

On a net basis, the 100% recoverable program represents 0% of the expenditures within this category since these projects costs are fully recoverable as a result of contributions from third parties such as developers and customers. This program incorporates new services, expansion developments, and other large developments planned within InnPower's service territory over the forecast period, including the Hewitt, Salem, and Royal Victoria Hospital (RVH) developments.

The observed decrease in System Access investments over the forecast period is largely because there are no commitments from Road Authorities on projects in years 2027/2028. However, since the level of investment required under this investment category is largely dependent on third-party requests, the level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of stakeholder requests received for services.

5.4.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. InnPower conducted an ACA to inform decisions for System Renewal within this DSP. The output of these assessments and processes led to targeted programs for capital expenditure and prioritization of System Renewal. Investments in System Renewal are captured in the table and figures below.

Table 5.4-27: Forecasted Net System Renewal Expenditures by Project ($'000)

Project	Forecast					Total ($'000)	Percent of Total
	2024	2025	2026	2027	2028		
IPCSR01 – Capital Trouble Calls and Emerging Projects	358	367	376	386	396	1,884	23.41%
IPCSR02 – Transformer Replacement Program	157	161	165	169	173	825	10.26%
IPCSR03 – Pole Replacement Program	363	500	513	525	538	2,439	30.32%
IPCSR04 – Reclosure Replacement Program	200	205	210	216	221	1,052	13.08%

Project	Forecast					Total ($'000)	Percent of Total
	2024	2025	2026	2027	2028		
IPCSR05 – Switch Replacement Program	166	170	175	179	183	873	10.85%
IPCSR06 – Switchgear Replacement Program	106	108	111	114	116	555	6.89%
IPCSR08 – Delta/Substandard Transformer Replacement	27	28	28	29	30	142	1.76%
IPCSR13 – Animal Mitigation	52	54	55	56	58	275	3.42%
System Renewal (net)	**1,429**	**1,594**	**1,633**	**1,673**	**1,716**	**8,045**	**100.00%**

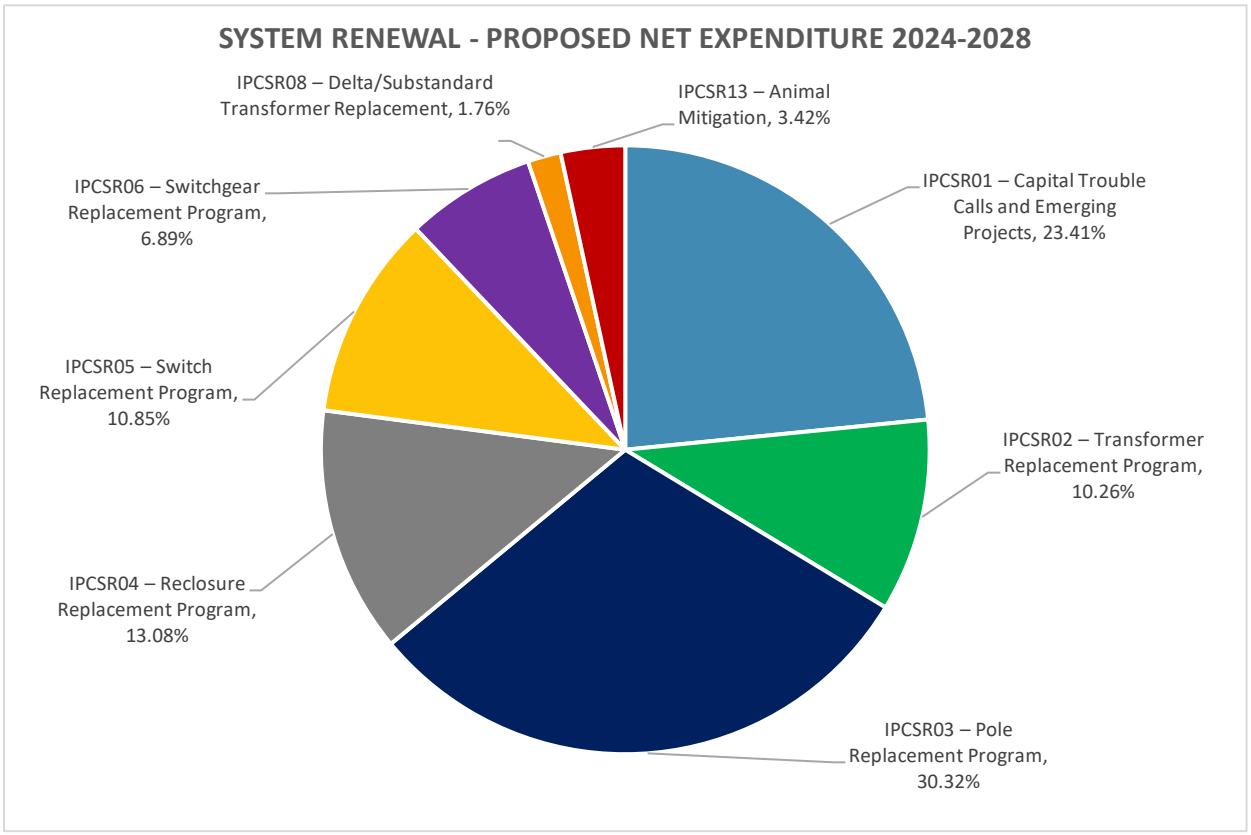


Figure 5.4-6: Forecasted Net System Renewal Expenditures by Project

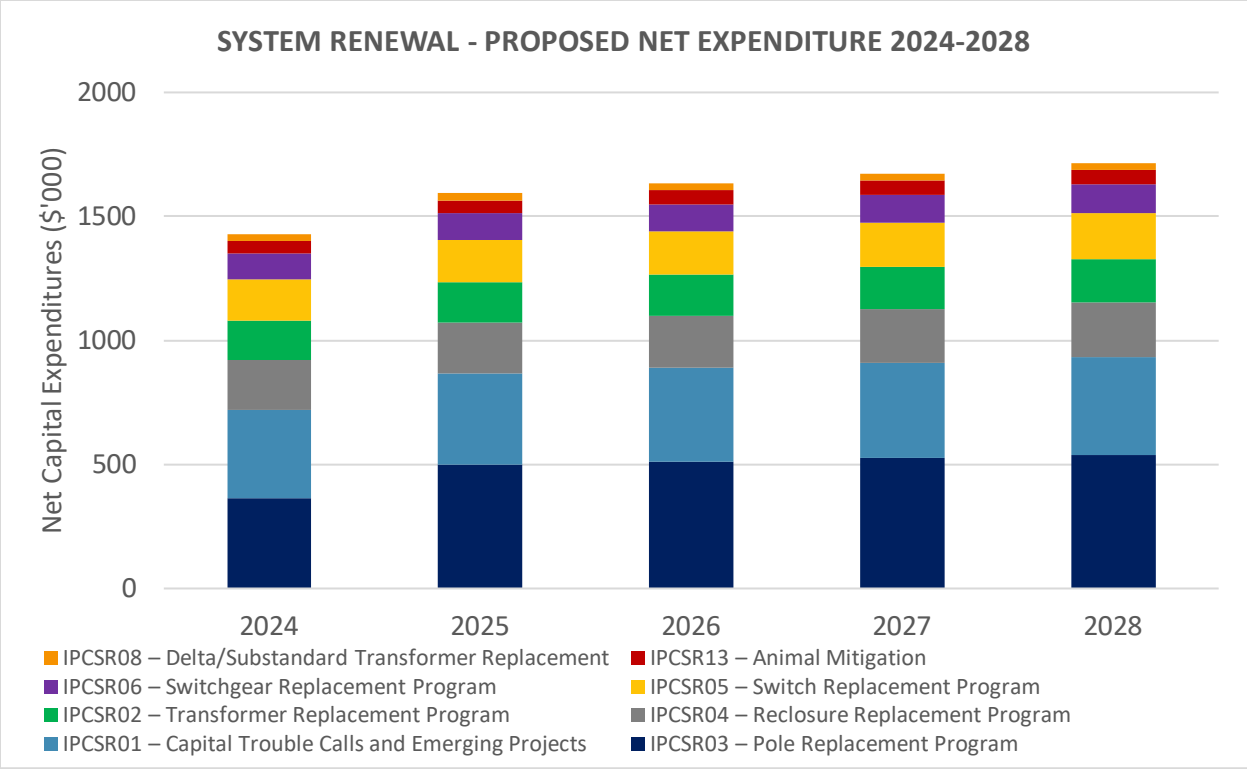


Figure 5.4-7: Forecasted Net System Renewal Expenditures by Project

When excluding the BATU and TS Project costs, net System Renewal is the second largest planned capital expenditure over the 2024–2028 forecast period representing 31.35% of overall spending. The level of investments required over the forecast period was determined using InnPower's AM process, which is described in detail in Section 5.3, and the ACA was used to assist in prioritizing investments in asset classes. Major programs within the System Renewal category include the proactive renewal and replacement of deteriorated assets at the end of their service life, including poles, transformers, reclosers, switches, and switchgear. Unplanned System Renewal projects are also budgeted each year to allow for replacement of electrical infrastructure damaged by inclement weather or unclaimed vehicle accidents. These programs are summarized below:

- **Pole Replacement Program (30.32% of forecast net expenditures):** Includes proactive replacement of poles that have been tested or deemed in need of replacement due to having a high risk of failure.
- **Capital Trouble Calls and Emerging Projects (23.41% of forecast net expenditures):** Includes unplanned capital jobs and Capital Trouble calls that arise due asset failure, customer complaints or compliance issues. This program also deals with storm damage and repairs that are capital in nature including pole, transformer, conductor, switch, and switchgear replacements.
- **Recloser Replacement Program (13.08% of forecast net expenditures):** Involved the proactive replacement of old oil type reclosers installed on InnPower's system with automated reclosers to effectively restore power during momentary power interruptions.
- **Switch Replacement Program (10.85% of forecast net expenditures):** Involves the proactive replacement of end-of-life gang operated and in-line switches based on the annual inspection and maintenance results.

- **Transformer Replacement Program (10.26% of forecast net expenditures):** Includes proactive replacement of distribution transformers within InnPower's distribution system based on results from the annual visual inspection program and ACA.
- **Switchgear Replacement Program (6.89% of forecast net expenditures):** Includes planned replacement of distribution system switchgears based on results from the annual visual inspection program and ACA.
- **Animal Mitigation (3.42% of forecast net expenditures):** This is to install animal guard that is missing based on the findings on the animal mitigation report that is performed during out annual OH inspection.
- **Delta/Substandard Transformer Replacement Program (1.76% of forecast net expenditures):** Updates legacy and substandard transformer construction within the distribution system that do not conform to current standards.

The observed increase in System Renewal spending over the forecast period is driven by the need to improve the reliability of the distribution system. As previously noted in Section 5.2.3.2.3, Defective Equipment was the top contributing cause to the total outages experienced by InnPower, accounting for 24.2% of the total outages experienced over the historical period. These failures resulted from equipment failures due to condition deterioration, ageing effects, or imminent failures detected from reoccurring maintenance programs. Additionally, as noted in Section 5.2.2.1, customers identified "*Maintaining and upgrading equipment to ensure a safe and reliable electricity supply"* and "*Investing in storm hardening (physical improvements that can make utility infrastructure more resistant to weather)*" as two of their top three priorities (after affordable cost of electricity, which was identified as the top priority).

The proposed level of System Renewal investment over the forecast period will allow InnPower to prioritize assets for replacement before experiencing a failure that may cause an outage, allowing InnPower to manage the system's health and performance more effectively in order to meet customer's expected performance and reliability.

5.4.1.2.3 System Service: Including BATU and TS Project

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet its operational objectives (such as reliability, grid flexibility, and DER integration), while being able to address future anticipated customer electricity requirements. System Service investments are also driven by the condition of station assets. Investments in System Service are captured in the table and figures below.

Table 5.4-28: Forecasted Net System Service Expenditures by Projects [Incl. BATU & TS Project]

Project	Forecast ($ '000)					Total ($ '000)	Percent of Total
	2024	2025	2026	2027	2028		
IPCSS05 - 27.6kV OH Dist Fault Indicators	0	0	0	71	78	149	0.29%
IPCSS06 - 44kV OH Dist Fault Indicators	0	0	0	69	76	145	0.28%
IPCSS08 - Communication Improvement	78	79	81	83	86	407	0.79%

Project	Forecast ($ '000)					Total ($ '000)	Percent of Total
	2024	2025	2026	2027	2028		
IPCSS12 - Station Rehab	0	228	468	625	644	1,965	3.81%
IPCSS24 - Normal Open Point Switch Installation	221	227	232	238	0	918	1.78%
IPCSS11 - InnPower TS	0	0	0	0	23,314	23,314	45.18%
IPCSS10 - H1 Transmission Line Extension to InnPower TS	0	0	0	0	8,220	8,220	15.93%
IPCSS17 - BATU	4,120	4,120	4,120	4,120	0	16,480	31.94%
IPCSS18 - 44kV Line Extension from Barrie	0	0	0	0	0	0	0.00%
System Service (net)	**4,419**	**4,654**	**4,902**	**5,207**	**32,417**	**51,599**	**100.00%**

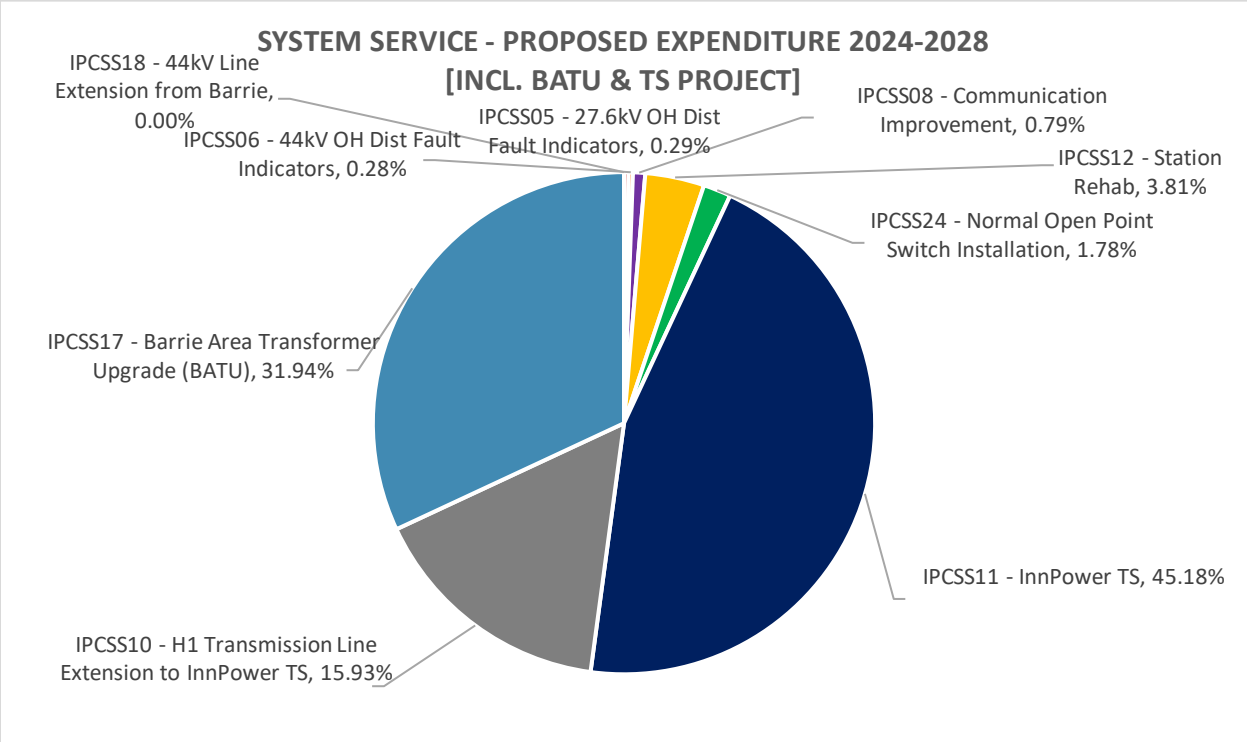


Figure 5.4-8: Forecasted Net System Service Expenditures by Projects [Incl. BATU & TS Project]

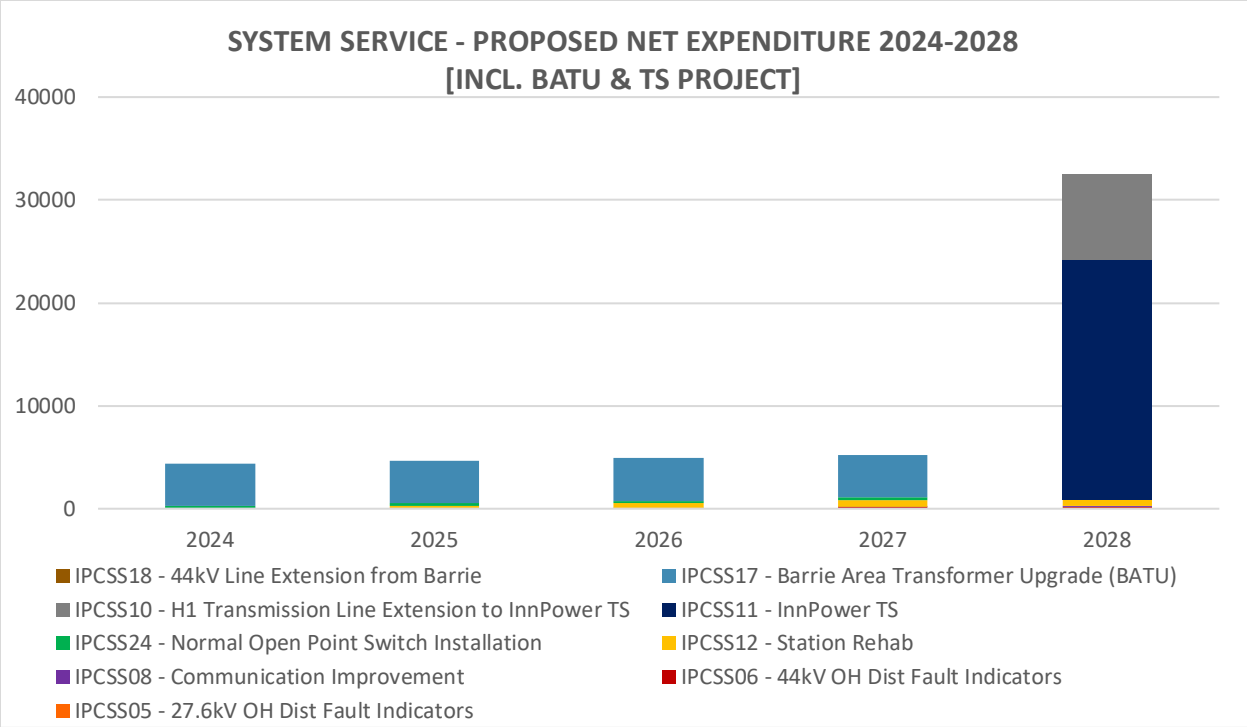


Figure 5.4-9: Forecasted Net System Service Expenditures by Projects [Incl. BATU & TS Project]

When including the BATU and TS Project costs, these projects alone account for nearly 93% of InnPower's overall net System Service capital expenditures over the forecast period. The year-over-year fluctuations observed are largely driven by the timing of the BATU and TS project costs. Overviews of these projects are provided below.

BATU Project Update

The BATU project consists of upgrading two existing 115 kV circuits to 230 kV between Essa TS and Barrie TS, constructing new 230 kV connection points at the Essa TS, and upgrading and expanding the existing Barrie TS with new 230-44 kV facilities. The transmission line and station work are required to increase supply capacity to accommodate customer load growth in the South of Barrie and Innisfil areas and to address immediate end-of-life issues with the current facilities. The BATU project was approved by the OEB in April 2020[6] and is currently being constructed by HONI.

The BATU project is undergoing material changes and in-service delays. The initial in-service date for the project was June 2022 and the OEB approved a total project cost of $91M, with $14.1M capital contributions from InnPower. However, due to changes in project scope, procurement delays based on market conditions and supply chain constraints, and commodity pricing, the initial project in-service date has been pushed by 18 months to December 2023. As such, the total cost of the BATU project is now estimated to be around $125M, with InnPower's contribution increasing to $20.6M. The capital contribution estimate is based on April 2022 cost estimates provided by the contractor. The BATU project was initiated after a regional planning study identified the need for increased capacity to accommodate future loading requirements in the Barrie region. The project involves expansion and

[6] OEB Decision and Order—Hydro One Networks Inc. Application for Leave to Upgrade Existing Transmission Line Facilities in the Barrie-Innisfil Area. EB-2018-0117. April 23, 2020.

upgrades to Essa TS, Barrie TS, and construction of a new transmission line between Essa TS and Barrie TS.

The Essa TS upgrade includes expansion of an existing 230kV yard to accommodate new 230kV transmission lines, reconfiguration of the existing 230kV lines inside the station, and removal of two existing auto transformers and associated switchyard infrastructure. As of April 2022, 75% of new 230kV buswork has been completed and the remaining work is to be completed during Fall outages. Similarly, 400m of total 600m of cable tremway were installed. The project costs and timeline for Essa TS have increased due to schedule delays and additional labour costs. Outage planners have required additional time due to complexity of the project and increased number of outages required to complete the work. The outage restrictions have also contributed to the complexity of the work. However, the increased costs associated with Essa TS has had no effect on InnPower's capital contribution amount.

The Barrie TS upgrade consists of expansion of the existing Barrie TS yard with new 230/44kV station facilities and removal of all 115kV equipment. As of April 2022, a majority of the 230kV helical piles have been installed, and excavation for Feeder duct banks have commenced, but the progress has been slow due large amounts of groundwater. The Barrie TS foundation scope has expanded, where specialized contractors and materials are required, which were not initially considered. It was discovered that there was soil contamination on site, which required proper remediation measures, increasing the cost of the project. Using helical piles construction methodology has also changed, causing additional activities and rebar work onsite. However, InnPower's capital contribution amount is not affected as similar construction scope and foundation type would be required to sustain the 115kV scenario as well.

The construction of new transmission lines to connect Essa TS and Barrie TS include a new 230kV double circuit transmission line called E28 and E29, and removal of the old 115kV circuits called E3B and E4B. Although Hydro One worked with the selected contractor to find savings for the E28/E29 line upgrade costs, the increased price of materials has led to higher costs. The largest increase in cost was seen in tower steel and conductors, with an estimated cost increase of $2.5M between September 2021 to April 2022. In addition to increased material costs, the procurement risks also include long lead time for material acquisition due to market conditions and global supply chain constraints, which has also delayed the construction schedule. In fact, Hydro One internal estimates showed a total project cost for E3B/E4B line upgrade increase from $24M to $36M between 2018 and 2021 alone. However, Hydro One does have preferred pricing from its vendors based on existing agreements and purchasing power, so savings of $1.5M might be possible. As such, due to significant increase in market pricing for E28/E29 line upgrades, InnPower's capital contribution has increased from $14.1M to $20.6M.

The BATU project's schedule delays and increased project costs have been caused by multiple factors from construction site delays to global supply chain constraints and increased material pricing. Due to the project delay, the interest costs of the project have also increased. Although InnPower's capital contribution has significantly increased due to the changes in E28/E29 line upgrades, InnPower still remains supportive of the project and wishes to proceed with the project as approved by the OEB. Hydro One has approached OEB with the updated costs and solution to financially support this project.

<u>New TS Project Update</u>

As detailed previously in Section 5.2.2.4, the regional planning process has identified an increased supply capacity need in the Innisfil area by 2025, and the preferred solution identified to address this need is to provide a 230 kV tap connection to Innisfil service territory for a new TS to increase supply capacity for InnPower through the construction of a new 230/27.6 kV 83MVA TS and connection to

the new 230 kV transmission lines that will be available upon the completion of the BATU project in 2022.

In coordination with HONI, it was determined that InnPower would be responsible for constructing the new TS and Hydro One Transmission would construct the transmission line expansion. Continued development and construction of the new TS Project and 230 kV line is expected to continue over the forecast period but given that the project in service date is expected to occur near the end of the forecast period (or potentially beyond), the costs associated with this project will remain in WIP and be addressed in InnPower's next rebasing application.

5.4.1.2.4 System Service: Excluding BATU & TS Project

For the reasons noted previously, the BATU Project and new TS Project are not considered to be part of InnPower's normal capital expenditures. To provide the OEB and interveners with a more realistic depiction of InnPower's System Service expenditures over the forecast period, the following table, figures, and project details are provided, exclusive of the BATU and TS Projects.

Table 5.4-29: Forecasted Net System Service Expenditures by Projects [Excl. BATU & TS Project]

Project	Forecast ($ '000)					Total ($ '000)	Percent of Total
	2024	2025	2026	2027	2028		
IPCSS05 - 27.6kV OH Dist Fault Indicators	0	0	0	71	78	149	3.76%
IPCSS06 - 44kV OH Dist Fault Indicators	125	128	131	69	76	529	13.33%
IPCSS08 - Communication Improvement	78	79	81	83	86	407	10.26%
IPCSS12 - Station Rehab	0	228	468	625	644	1,965	49.52%
IPCSS24 - Normal Open Point Switch Installation	221	227	232	238	0	918	23.14%
System Service (net)	**424**	**662**	**912**	**1,086**	**884**	**3,968**	**100.00%**

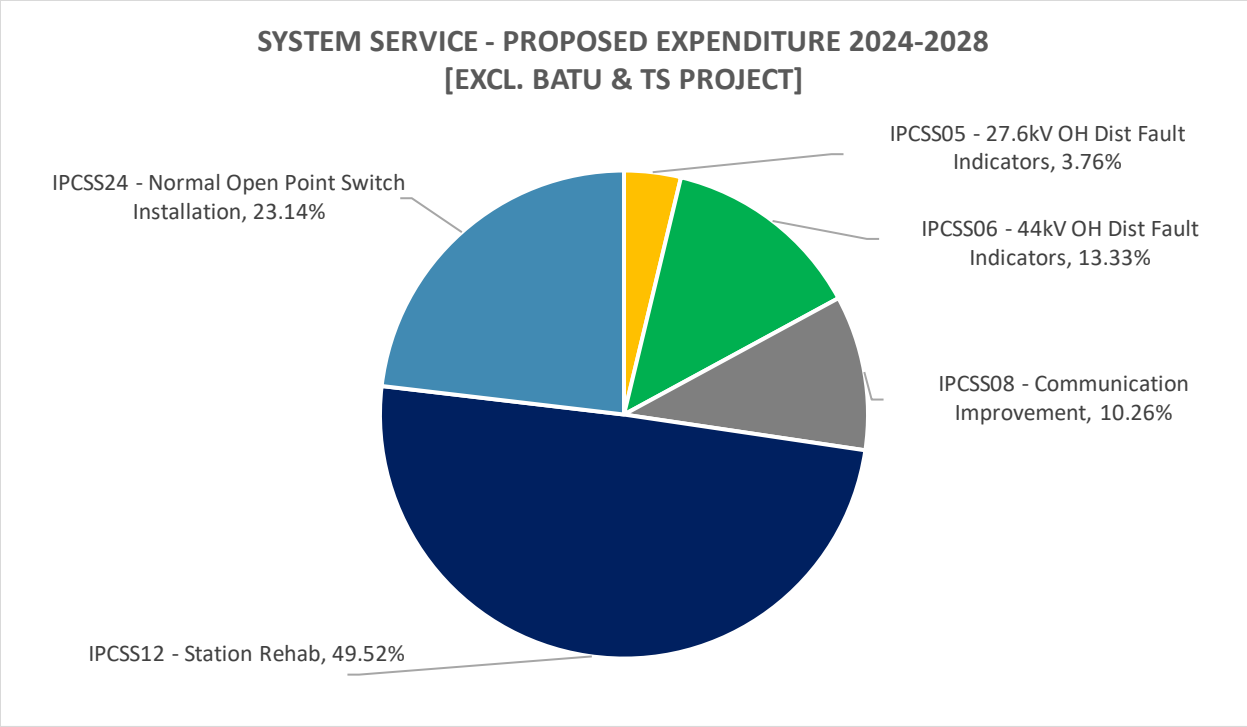


Figure 5.4-10: Forecasted Net System Service Expenditures by Projects [Excl. BATU & TS Project]

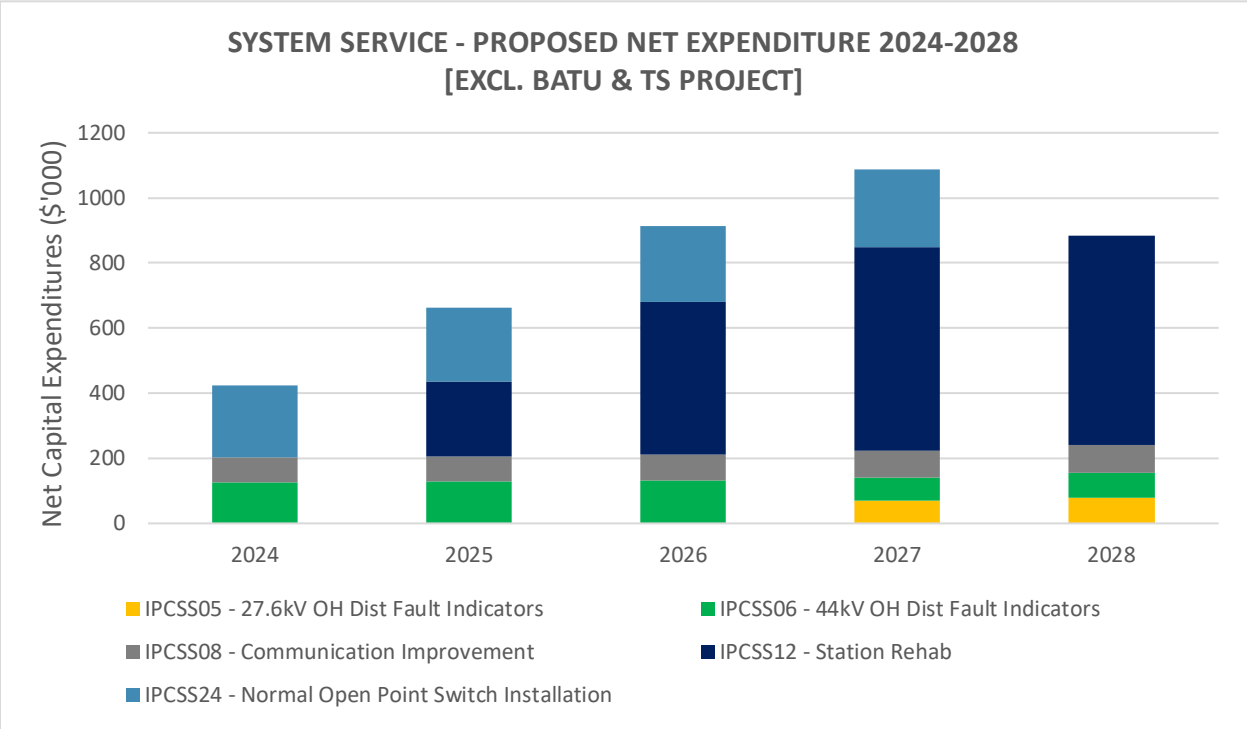


Figure 5.4-11: Forecasted Net System Service Expenditures by Projects [Excl. BATU & TS Project]

When excluding the BATU and TS Project costs, Station Rehab represents the largest portion (49.52%) of the expenditures within this category. This project involves a variety of station rehabilitation work including but is not limited to retrofitting foundations, implementing oil containment, repairing grounding and neutral systems, and addressing leaking transformers. Considering the load growth in InnPower's service area, InnPower is actively working with a group of developers to upgrade transformers at certain stations over the 2024–2025 period. Since these projects are mostly recoverable, the net Station Rehab costs are lower in these years relative to InnPower's planned station rehabilitation costs in years 2026–2028, which are not recovered by third-party contributions.

The Normal Open Point Switch Installation project represents the second largest driver within this category (23.14%). This project is to replace manual single-phase inline switches that are normal open points between station with remote load break-operated switches, in order to improve reliability, restoration times, load transfer and limit truck rolls.

InnPower's distribution fault indicator replacement programs combined represent the next largest driver within the System Service category (17.09%). These programs involve the installation and commissioning of new 27.6 kV and 44 kV fault indicators on distribution lines to locate faults faster to address system issues, reduce momentary interruptions, reduce outage durations, and improve the average restoration time. To help accommodate and balance the increased level of investments and resources required under other investment categories over the forecast period, InnPower has deferred spending towards the 27.6 kV fault indicator program to years 2027 and 2028 whereas decreasing the 44 kV fault indicator program spending over the years 2027 and 2028.

At 10.26%, Communications Improvements encompass the remaining budget within this investment category. This program involves upgrading EOL communication assets such as Hub Switches and DragonWave Point-to-Point 23/18GHz and Point to Multi Point WIMAX 1.8GHz radios and related equipment such as battery back ups Power Over Ethernet (POE), surge arrestors, and antennas.

The observed trend in System Service spending from 2024 to 2028 is driven primarily by the Station Rehab program. This program includes costs associated with increased capacity needs at the DS level to accommodate new loads, and costs to replace/rehabilitate EOL equipment such as power transformers. Third-party contributions towards the Station Rehab program in years 2024 and 2025 have lowered the net System Service budgets in these years, which explains the observed increase over the forecast period. This increase is also impacted by the 27.6 kV fault indicator program spending expected to restart in year 2027. The drop observed in 2028 is due to the completion of the Normal Open Point Switch Installation project in 2027.

5.4.1.2.5 General Plant

Expenditures in the General Plant category are driven by the need to modify, replace, or add to assets that are not part of the distribution system but support InnPower's daily operations. The items within this category are important and contribute to the safe and reliable operation of a distribution system. If General Plant investments are ignored or deprioritized this could lead to future operational risks or increased investments in future years. InnPower's planned capital investments in General Plant are captured in the table and figures below.

Table 5.4-30: Forecasted Net General Plant Expenditures by Projects ($'000)

Project	Forecast ($ '000)					Total ($ '000)	Percent of Total
	2024	2025	2026	2027	2028		
IPCGP01 - IT Hardware	194	199	204	214	219	1,030	23.35%
IPCGP02 - IT Software	125	128	131	135	138	657	14.89%
IPCGP04 - Building & Fixtures	75	77	79	81	83	395	8.95%
IPCGP05 - Finance IT	40	41	42	43	44	210	4.76%
IPCGP06 - Engineering IT	35	0	60	60	260	415	9.41%
IPCGP10 - Tools, Shop & Garage Equipment	83	85	87	89	91	435	9.86%
IPCGP12 - Fleet & Single Bucket Truck	470	200	200	200	200	1,270	28.79%
General Plant (net)	**1,022**	**730**	**803**	**821**	**1,035**	**4,391**	**100.00%**

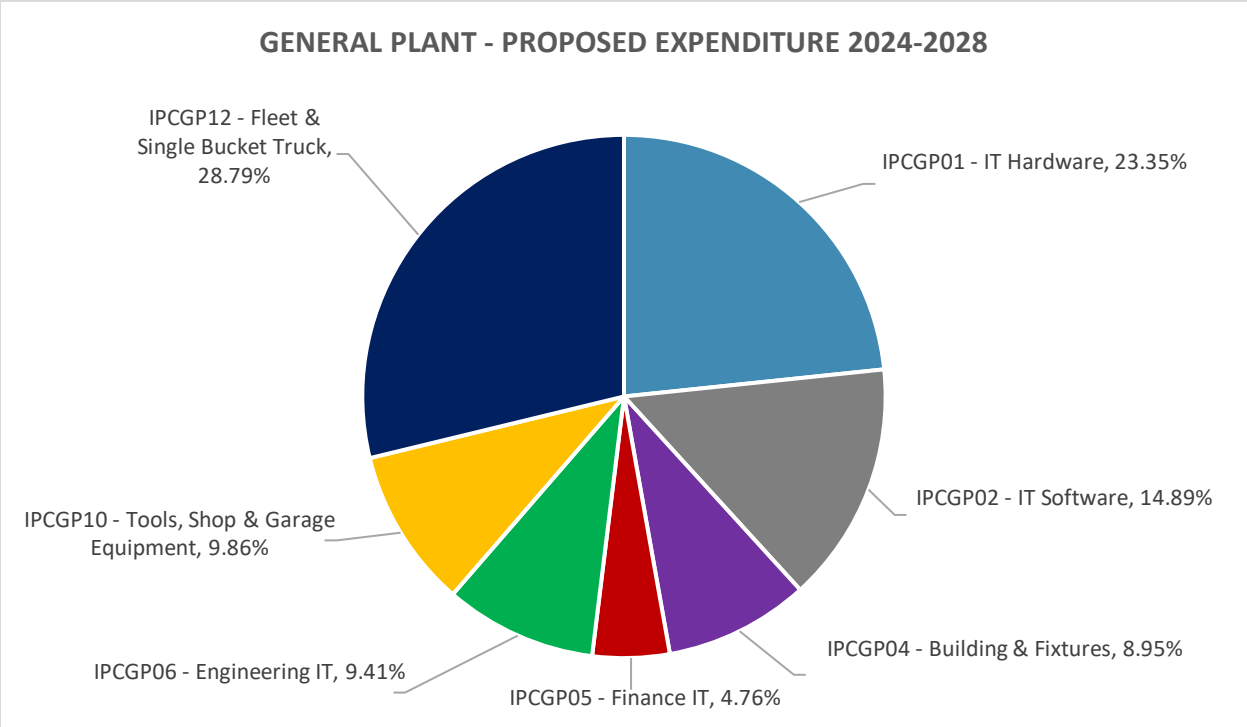


Figure 5.4-12: Forecasted Net General Plant Expenditures by Projects

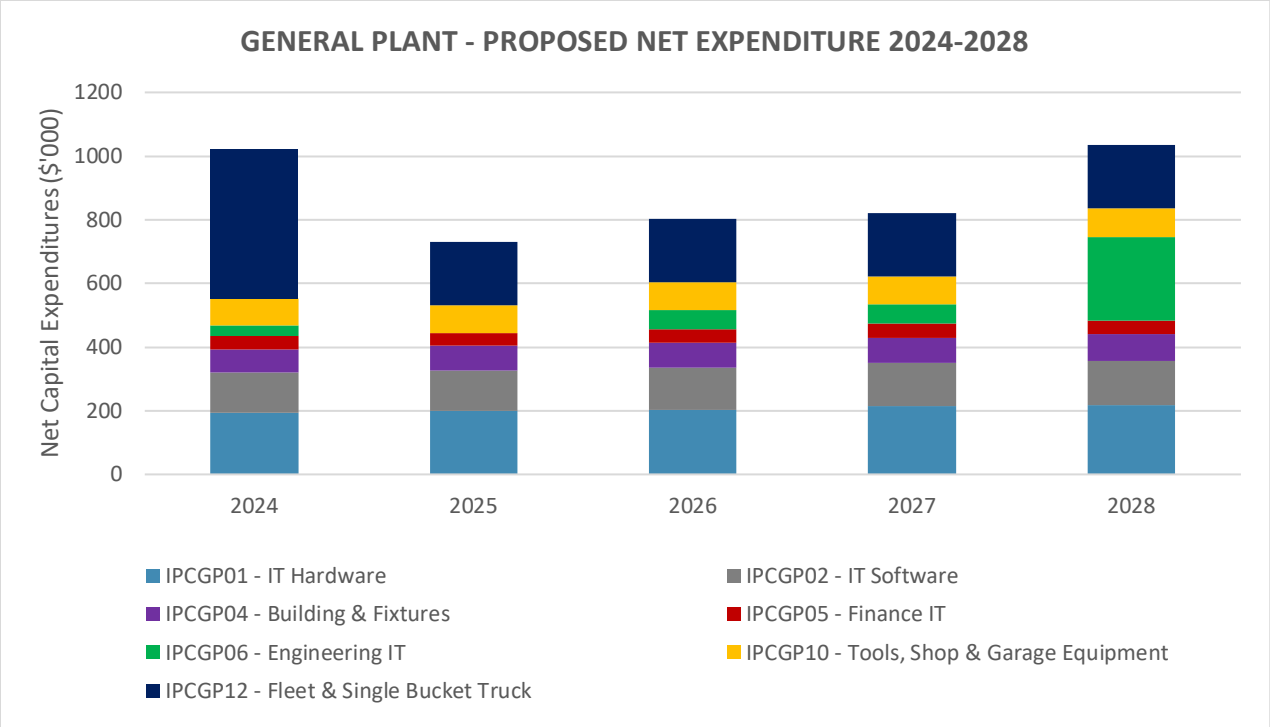


Figure 5.4-13: Forecasted Net General Plant Expenditures by Projects

When excluding the BATU and TS Project costs, net General Plant expenditures represent 17.19% of overall forecast spending. The proposed expenditure level is estimated based on the historic spending levels and specific information available about planned projects at the time of preparation of this DSP.

At 28.79%, InnPower's fleet and single bucket truck program represents the largest portion of expenditures within this category. This program includes the replacement of a bucket truck in the 2024 Test Year, with the remaining annual costs being allocated towards general fleet upkeep.

IT Hardware and IT Software represent the next largest portions of forecast expenditures, at 23.35% and 14.89%, respectively. These programs are comprised of an ongoing business requirement to replace end user computers and software, as well as network infrastructure and software.

The remaining budget is allocated amongst the four following programs:

- **Tools, Shop and Garage Equipment (9.86%):** Includes investments in various tools and small equipment necessary to carry out the operations and maintenance activities of the engineering, operations, and stores departments.
- **Engineering IT (9.41%):** Investments towards engineering IT such as SCADA, AM, and engineering analysis to allow for necessary process improvements to the engineering and operations departments in an effort to improve reliability and reduce costs.
- **Buildings and Fixtures (8.95%):** Comprises general investments and improvements to buildings and fixtures.
- **Finance IT (4.7%):** Includes general investments in finance IT, such as improvements in Prophix and software used for purchasing, and other business process efficiencies.

The year over year fluctuations observed in forecast General Plant spending are primarily being driven by fluctuations in project costs. The observed increase in the 2024 Test Year is due to a bucket truck replacement as part of InnPower's proposed Fleet program that was purchased in 2021 but is being manufactured with the delivery date in 2024; while the increase in 2028 is driven by an increase in the Engineering IT Program costs associated with implementing FLISR, a self-healing system to continue improving reliability, and implementing a real-time test environment for InnPower's SCADA System.

5.4.1.2.6 Investments with Project Lifecycle Greater than One Year

For capital investments that have a project lifecycle greater than one-year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress.

For capital projects spanning multiple years, costs remain under construction WIP until the capital project is in service. Therefore, capitalization will only occur at the end of the project once it is in service and is considered to be "used and useful."

A key example of a multi-year capital project discussed in this DSP is the new TS Project. Although the project costs span multiple years, costs will remain under WIP throughout the execution of the project and will only be capitalized once in service. Since the anticipated in-service date of the new TS Project is expected to be near the end of (or beyond) the forecast period, the project costs will remain in WIP and be addressed in InnPower's next rebasing application.

5.4.1.3 Comparison of Forecast and Historical Expenditures

The distributor must provide an analysis of capital expenditures in the DSP's forecast period as compared to the historical period.

A comparison of InnPower's capital expenditures in the DSP's forecast period as compared to the historical period is provided in the following subsections.

5.4.1.3.1 System Access

As shown in Figure 5.4-14, InnPower's System Access forecast average is 63% greater than the historical plus bridge year average. This is primarily due to some known customer growth areas in InnPower's service territory (as noted in Section 5.3.2.1, InnPower's conservative customer growth projection estimates an average growth of 5% annually over the forecast period, with the optimistic growth projection estimating over 12% annual growth), as well as allowing InnPower to allocate adequate resources and funds to accommodate potential future unknown connections. The observed decreasing trend in System Access investments over the forecast period is due to the current lack of third-party project commitments (e.g.: road authority works); however, these projects are difficult to forecast and may still change as these are dependent on customer and external drivers.

The historical System Access trend is variable year over year due to the unpredictability of customer connection service requests, externally initiated subdivision and relocation projects, metering upgrades, as well as third-party delays, deferrals, cancellations, and/or the introduction of new or additional works.

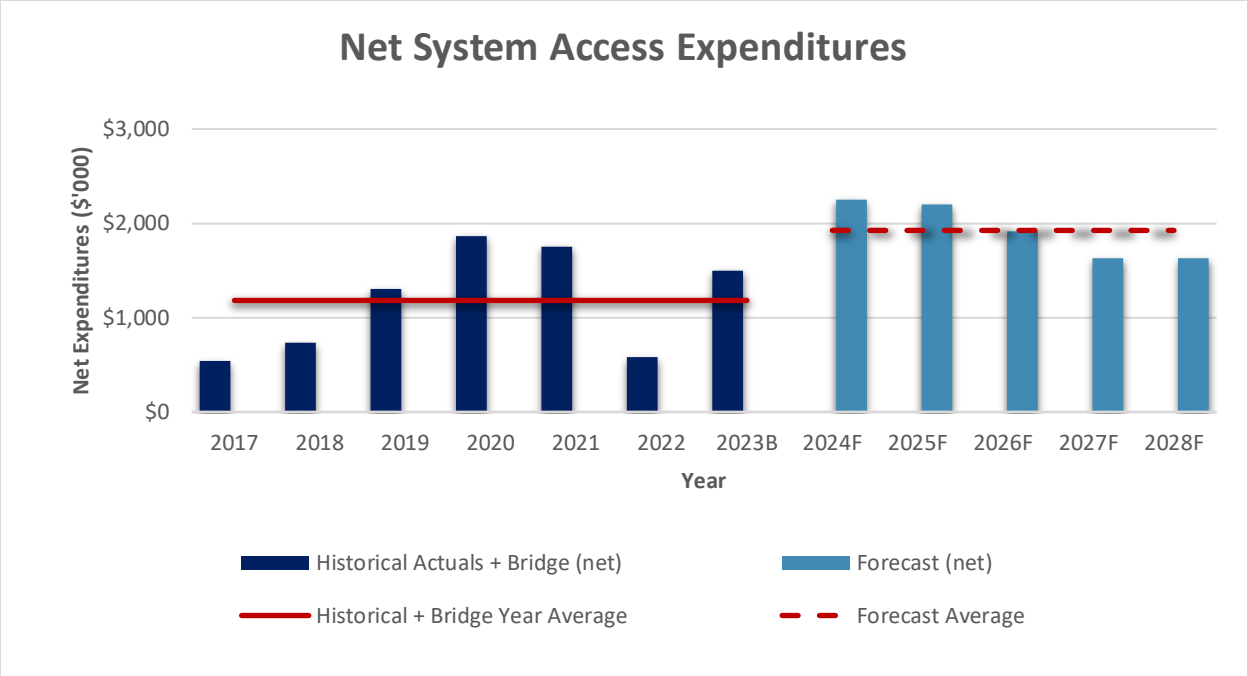


Figure 5.4-14: System Access Comparative Expenditures

5.4.1.3.2 System Renewal

System Renewal expenditures are impacted by planned capital investments and the objective to address any condition-based maintenance activities within the asset system to meet customer's expected performance and reliability. As shown in Figure 5.4-15, the forecast average for System Renewal is only 16% lesser than the historical plus bridge year average.

The limited increase in forecast System Renewal spending is driven by the need to accommodate and balance the increased level of investments and resources required under other investment categories over the forecast period to accommodate other factors such as growth. This includes known large, mandatory System Access projects that are currently planned in. Should any of these projects or needs change during the forecast period, InnPower will reassess investment in other categories including System Renewal and reallocate expenditure to the next highest priority projects. At the same time, the level of forecast System Renewal spending is reflective of the ongoing efforts needed in asset renewal to keep pace with recommendations identified in the ACA, while staying in step with the customer's top priorities of maintaining affordable cost of electricity and maintaining and upgrading equipment to ensure a safe and reliable electricity supply.

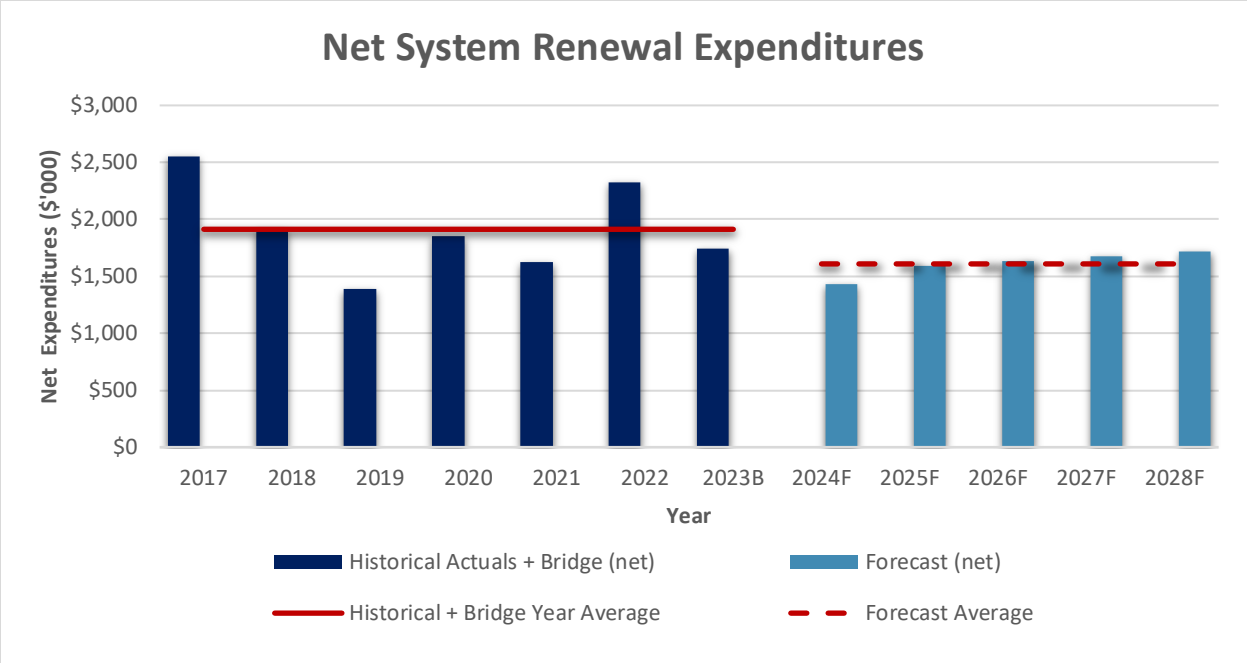


Figure 5.4-15: System Renewal Comparative Expenditures

The forecast System Renewal spending is expected to be relatively stable with only small year-over-year increases to accommodate the proactive and reactive System Renewal investments needed to meet customer's expected performance and reliability, while also accounting for inflation. The year-over-year variations observed over the historical period are driven by a variety of factors, including but not limited to resource and funding availability, higher than expected emerging capital jobs and trouble calls, and reassignment of work to accommodate higher priority work.

5.4.1.3.3 System Service

When including the BATU contributions and TS Project costs, the forecast average for System Service is 606% greater than the historical plus bridge year average, as shown in Figure 5.4-16.

This significant increase is primarily due to the combined costs of the new TS Project in 2028. Continued development and construction of the new TS Project and 230 kV line is expected to continue over the forecast period; however, given that the project in service date is expected to occur near the end of the forecast period (or potentially beyond), the costs associated with this project will remain in WIP and be addressed in InnPower's next rebasing application.

The BATU contributions are constant over the years 2024 to 2027 thereby contributing to relatively homogenous forecasted spending over the same years.

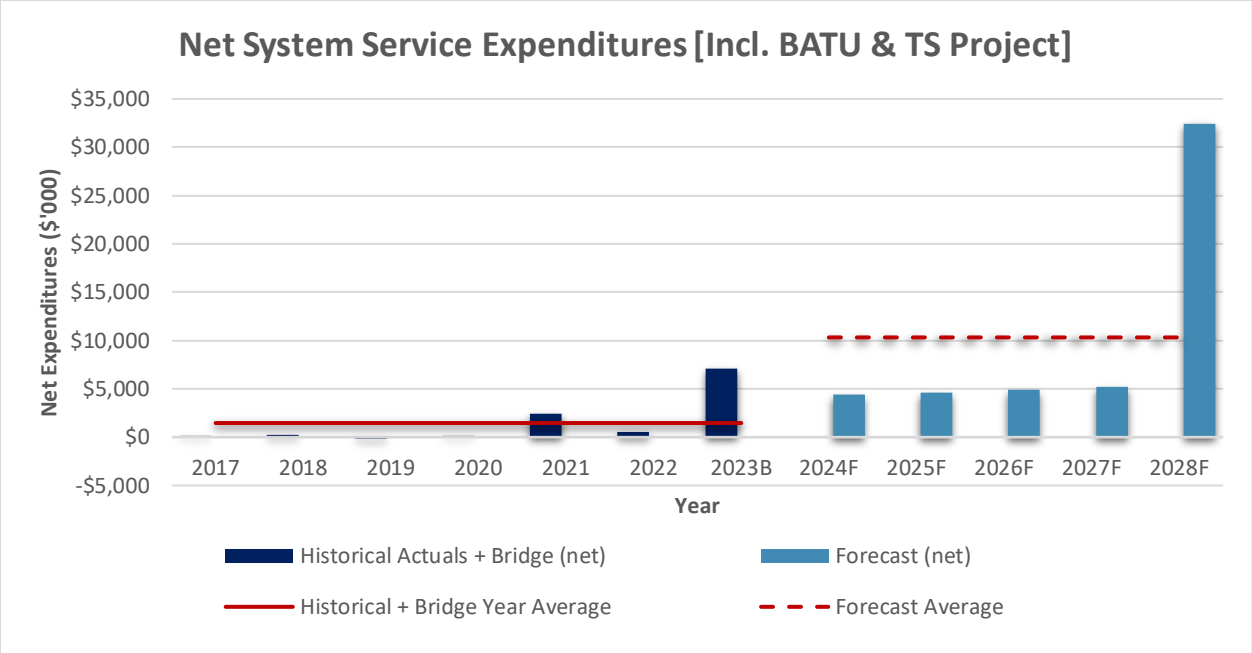


Figure 5.4-16: System Service Comparative Expenditures [Incl. BATU & TS Project]

When excluding these project costs associated with the BATU and TS Project, the forecast average for System Service is 33% greater than the historical plus bridge year average, as shown in Figure 5.4-17.

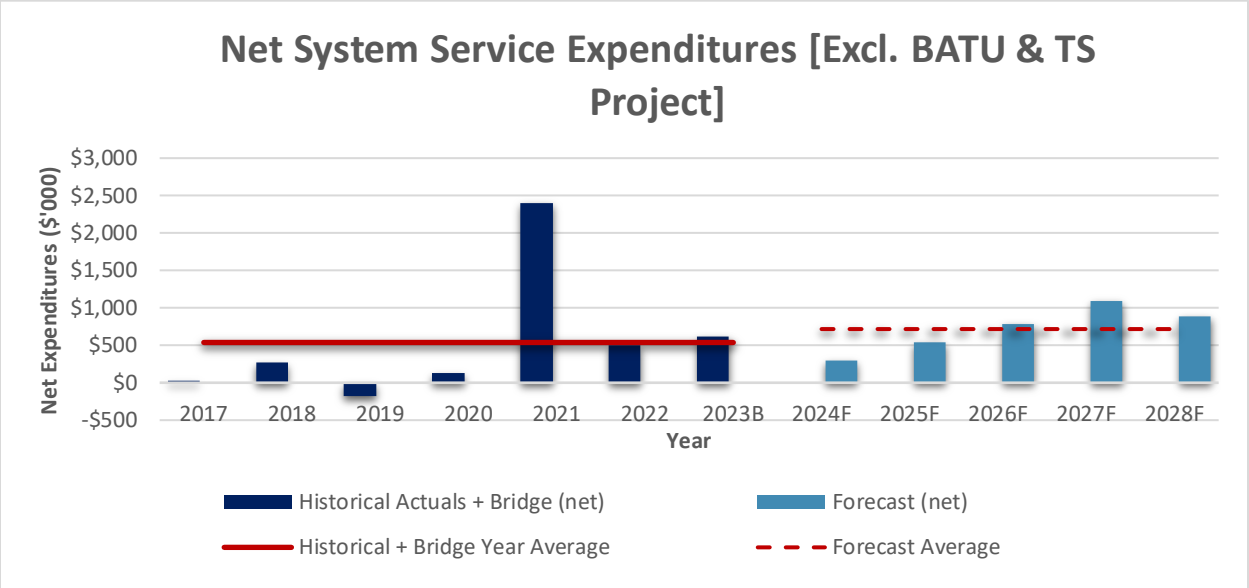


Figure 5.4-17: System Service Comparative Expenditures [Excl. BATU and TS Project]

The observed increase in spending is primarily driven by station rehabilitation works needed to accommodate increased capacity needs at the DS level to accommodate new loads, and costs to replace/rehabilitate end of life (EOL) equipment such as power transformers. Third-party contributions towards the Station Rehab program in years 2024 and 2025 have lowered the net System Service budgets in these years, which explains the increasing trend observed over the forecast period. This

increase is also partially driven by the fault indicator program spending expected to restart in year 2027 to support the continued automation of the system. The drop observed in 2028 is due to the completion of the Normal Open Point Switch Installation project in 2027.

The year-over-year variations observed over the historical period are driven by a variety of factors, including but not limited to project deferrals to better align with the timing of other related projects, reassignment of budgets to accommodate higher priority work, and deferrals due to COVID-19 impacts. Another major driver was the cancellation of the planned Friday Harbour DS as a result of a change in strategy and decision to instead pursue the construction of the new TS Project to meet the long-term demand in South Barrie and Innisfil Area.

The Big Bay Point DS project (started in 2019) was rebuilt due to expansion. The third-party paid a large sum upfront and this project was completed in 2020. The observed jump in 2021 is due to InnPower undertaking majority of the rehab and upgrade of Innisfil DS. This project was carried over to completion in 2022, hence explaining the observed drop in 2022. In a nutshell, the work executed in 2017 and 2018 was rehab driven, the work completed in 2019 and 2020 was third-party expansion driven, while the work undertaken in 2021 and 2022 was rehab driven (Innisfil DS).

The 2023 bridge year budget includes spending towards InnPower's Station Rehab and Normal Open Point Switch Installation programs, as well as spending towards InnPower's 27.6 kV and 44 kV distribution fault indicator programs, 44 kV switch commissioning and SCADA-Mate/Viper commissioning.

5.4.1.3.4 General Plant

InnPower continues to use its framework to address critical issues needed within the General Plant program, including existing facilities, fleet, and IT assets. As shown in Figure 5.4-18, the forecast average is 7% greater than the historical plus bridge year average. This is primarily due to the replacement of a bucket truck in the 2024 Test Year and increased spending in IT assets. The jump in 2028 is explained by an increase in Engineering IT to implement FLISR, which is a self-healing system to continue improving reliability, and also implement a real-time test environment for the SCADA System.

The year-over-year variations observed over the historical period are driven by a variety of factors, including but not limited to project deferrals to better align with the timing of other related projects, decisions to rent and lease equipment and vehicles instead of purchasing them, and the decision to pool vehicles between employees to reduce the need for additional vehicles. Another major driver is the purchase of a new double bucket truck in 2018; small general fleet upgrades and replacements in 2017 and 2019; followed by the purchase of a new RBD and buyout of leased single bucket trucks in 2021; and the buyout of leased vehicles due to supply chain issues.

The 2023 budget is associated with leasing a small service truck to accommodate the small rural roads in InnPower's service area, as well as the replacement/addition of general pool vehicles to accommodate additional staff and the end of existing leases.

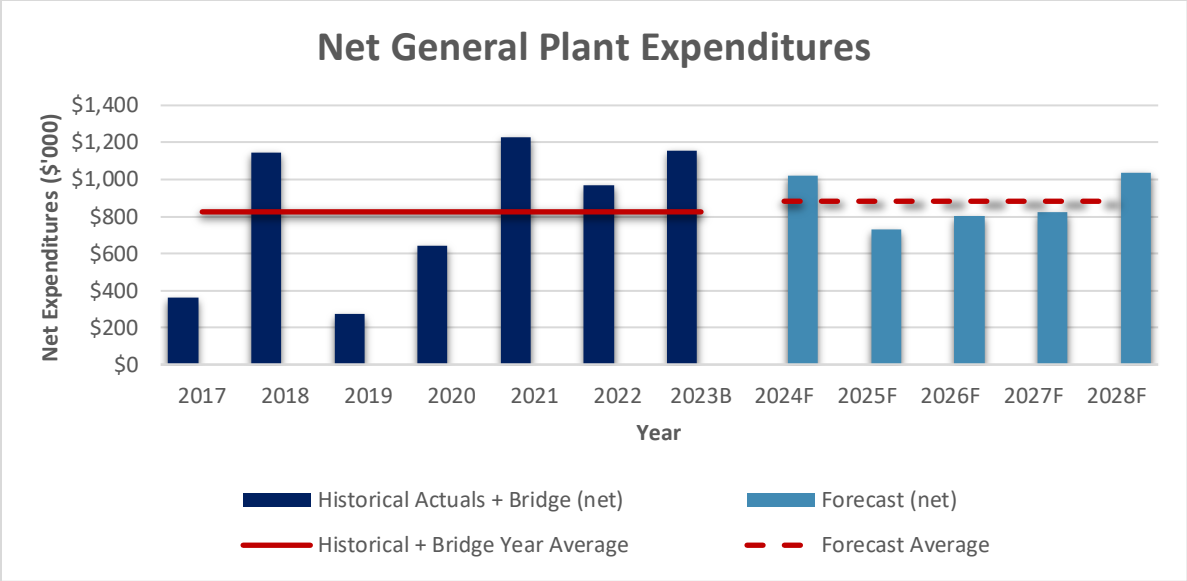


Figure 5.4-18: General Plant Comparative Expenditures

5.4.1.3.5 Overall Capital Expenditures

The overall net capital expenditure trends over the 2017 to 2028 period, including the BATU and new TS Projects, are shown in Figure 5.4-19. The average overall capital expenditures forecast is approximately 174% higher than the historical plus bridge-year average. This is largely as a result of the costs associated with the BATU and TS Projects and other capital investments required to service the unprecedented growth of InnPower's communities.

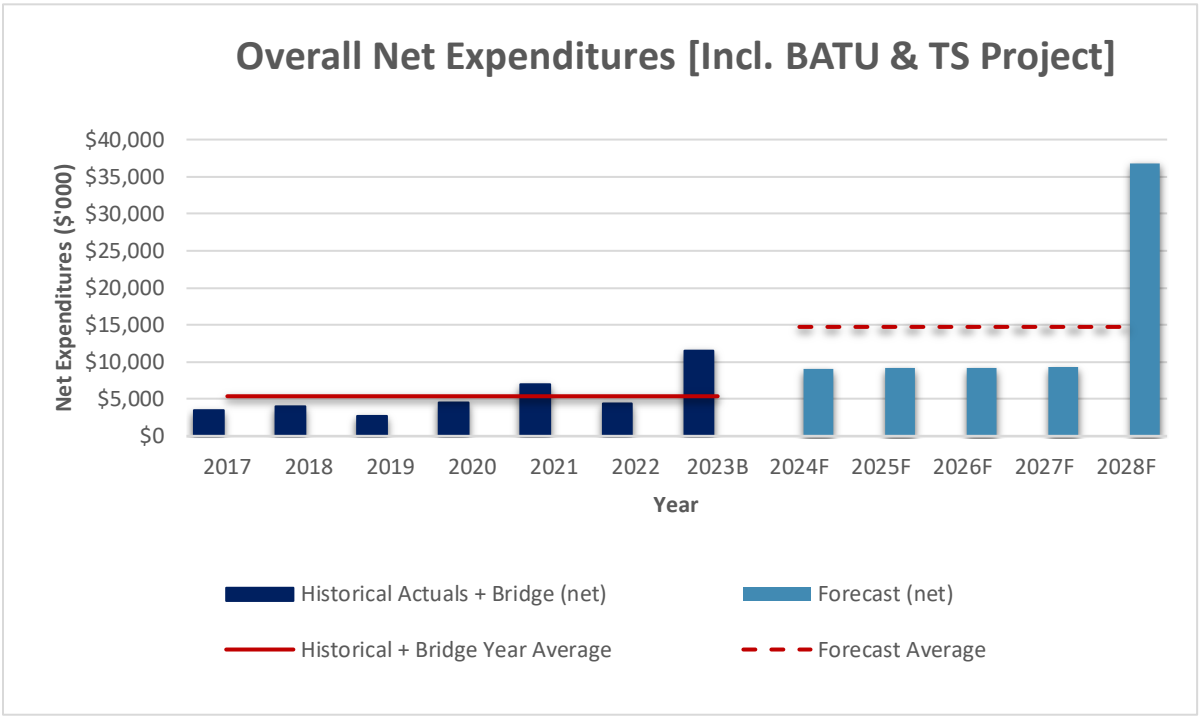


Figure 5.4-19: Net Capital Expenditures [Incl. BATU and TS Project]

When comparing overall net expenditures over the historical and forecast periods, it is important to compare expenditures on an *apples-to-apples* basis. Since the BATU contributions and new TS Project are not considered to be part of InnPower's normal capital expenditures, these costs should be removed to provide the OEB and interveners with a more representative comparison of the forecast expenditure compared to historical expenditures.

When excluding the BATU and TS Project costs, the average overall capital expenditures forecast is approximately 15% greater than the historical plus bridge-year average.

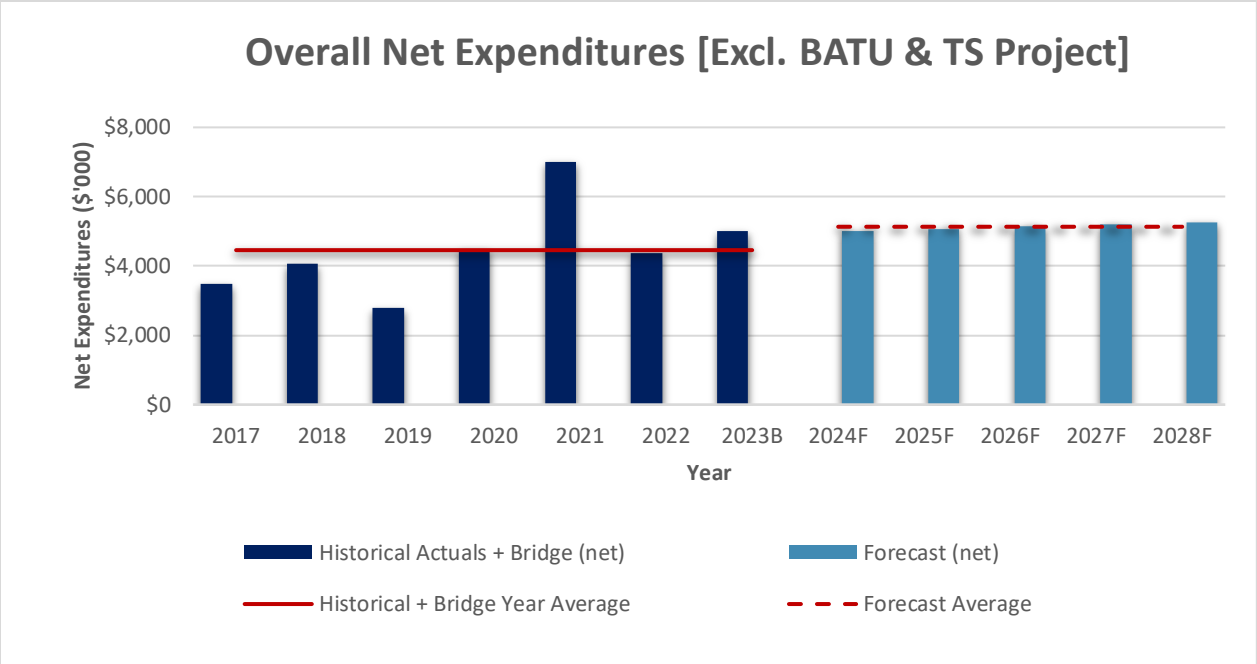


Figure 5.4-20: Net Capital Expenditures [Excl. BATU & TS Project]

Given the rising cost of goods and services required to complete the forecast work and given the amount of growth expected in InnPower's service territory, a 15% increase over the forecast period is considered to be quite modest. As detailed in the previous sections, the overall increase reflects the increase in System Access to accommodate known customer growth areas in InnPower's service territory, continued investments in System Renewal to maintain and upgrade equipment to ensure a safe and reliable electricity supply, increase in System Service to address rehabilitation works needed to accommodate increased capacity needs and costs to replace/rehabilitate EOL equipment such as power transformers, and an increase in General Plant to maintain and upgrade InnPower's fleet, IT, buildings, tools and equipment in order to continue serving InnPower's growing customer base.

5.4.1.4 Important Modifications to Typical Capital Programs

The distributor must provide a summary of any important modifications to typical capital programs since the last DSP (e.g.: changes to individual asset strategies).

Since the last DSP, there was a change in the proposed strategy for meeting capacity constraints. In the last DSP, InnPower had proposed to build the Friday Harbour DS (10MVA) station to accommodate the loads associated with new developments in Innisfil and South Barrie. When conducting further system planning studies, InnPower identified the system constraint to be at the 44

kV sub-transmission level, and as a result, the originally proposed Friday Harbour DS solution would not be adequate to meet the load growth. For this reason, InnPower revisited its strategy and determined that it would need to upgrade existing DS to meet the short term/mid term demand and invest in building a new 2x83 MVA TS to meet the long-term demand in south Barrie and Innisfil Area. New recoverable distribution expansion projects are also underway to help accommodate the future load growth.

5.4.1.5 Forecast Impact of System Investments on System O&M Costs

System O&M costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. A distributor is expected to consider the reduction in O&M costs when planning capital investments. A description of the impacts of capital expenditures on O&M must be given for each year, or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital investment.

Table 5.4-31 summarizes the forecast system O&M spending over the forecast period.

Table 5.4-31: Forecast System O&M Expenditures

Category	Forecast ($ '000)				
	2024	2025	2026	2027	2028
System O&M	3,091	3,307	3,406	3,508	3,614

While it is hypothesized that System Renewal investments would avoid increases to system O&M costs, it is also expected that System Access and System Service investments—both of which increase the asset pool requiring maintenance—would contribute to system O&M cost increases. Due to the high customer growth rates due to new development over the forecast period, InnPower's asset pool is expected to significantly increase in the near term, which will in turn affect system O&M costs. InnPower like many other utilities experiences increases in supply chain, contractors, and labour costs, which are contributing to an increase in System O&M costs. In addition, InnPower's workforce increase to meet customer growth and needs further contributes towards additional costs to its System O&M expenditures. Combining all these factors articulated above, this means that InnPower's system O&M costs are forecast to increase over the forecast period.

5.4.1.6 Non-Distribution Activities

A statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget.

There are no expenditures for non-distribution activities in InnPower's budget.

5.4.2 JUSTIFYING CAPITAL EXPENDITURES

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based.

InnPower's overall capital plan consists of many converging inputs that drive and influence the direction of the capital expenditures. InnPower's objective with regards to capital expenditures is to

meet all regulated requirements while managing the assets in a manner that minimizes the costs to InnPower customers and ratepayers.

Customer Value

Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate identification, optimization, prioritization, pacing of capital-related expenditures, and how it developed its overall capital budget envelope.

Delivering value to customers and other stakeholders is of critical importance to InnPower, as highlighted by InnPower's mission and vision statements:

- InnPower's mission statement is *"to deliver the energy our communities depend on to grow and prosper, with a commitment to safety and reliability, and a passion for value-added services to our customers, employees and shareholder."*
- InnPower's vision is *"to be one of Canada's Most Innovative Utilities, committed to boldly leading change, and achieving maximum value for our stakeholders."*

As previously discussed in Section 5.2.2.1, InnPower regularly engages with its customers to share information, educate customers, and to gather their opinions and insights on its services and on key priorities. Customer needs, preferences, priorities and expected level of service are key inputs considered when developing capital plans.

InnPower's AM objectives, which drive planning and decision making, include ensuring public and worker safety, maintaining system reliability and resiliency, managing costs, accommodating organic load growth, and mitigating environmental risks, all of which deliver value to customers.

By prioritizing System Access projects such as new customer connections, service requests, new subdivisions, municipality expansions and MTO projects, InnPower ensures that customer needs and requests are being met.

The scope of capital investments planned in the System Renewal category has also been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level while also keeping the overall investment envelope for this DSP within a range that would not result in retail rates escalations beyond the affordability of InnPower's customer base. This is in alignment with the top two customer priorities identified in a recent survey, which corresponds to "*Affordable cost of electricity*" and "*Maintaining and upgrading equipment to ensure a safe and reliable electricity supply*".

The proposed System Service investments deliver value to customers by accommodating expected load growth and improving grid operation performance. By developing and investing in projects such as the BATU project and new TS Project, InnPower is ensuring that customer needs, and growth will be met over the forecast period and beyond. InnPower's plans to automate more of its network over the forecast period will also enable InnPower to use FLISR, which is a fundamental concept of a self-healing network. These investments will help to reduce the size and duration of outages and improve response times, which is consistent with customer's desire for a reliable electricity supply and improved outage response times.

InnPower's General Plant investments are also selected and prioritized such that InnPower can continue to operate safely, efficiently and support other work. Recent and planned IT-related upgrades including the migration to a GIS-UNM and ongoing upgrades to its OMS will allow InnPower to make

faster decisions to troubleshoot and improve its system reliability and continue to make prudent decisions into asset maintenance and replacement to keep costs down for customers.

In order to align InnPower's overall capital budget envelope with customer expectations, InnPower has prioritized and optimized its proposed capital investments such that the most critical projects and programs have been budgeted over the forecast, while a number of lower priority, less critical scoped projects and programs have been either deferred, reduced, or eliminated from the budget envelope. Project and program deferrals are detailed further in Section 5.4.2.1 below.

Technological Changes and Innovation

A distributor should also keep pace with technological changes and integrate cost-effective innovative investments.

With the emergence of changing policies, net zero targets, increasing prioritization of electrification, innovative technologies, and customer expectations, the distribution grid is quickly evolving from a system-centric, top-down, one-way power flow system to a customer centric, bi-directional power flow system. Customers now have the capability to generate their own electricity via Distributed Energy Resources (DERs), and as a result, distribution system planning and operations are becoming increasingly complex, and maintaining grid integrity is becoming more challenging. Practices which have historically been acceptable for the traditional grid need to evolve, and an improved and more modernized grid is required to accommodate this evolution.

Innovation is part of InnPower's corporate vision and among its core values (i.e.: Innovation and Sustainability). Where possible, InnPower investigates and leverages innovative ways to improve asset and system performance, operations, and maintenance to meet the needs of customers and demonstrate leadership in technology advancement. A few examples of technological improvements and innovation either recently implemented or planned over the forecast period are noted below:

- **GIS Upgrade:** InnPower has recently completed the migration from its previous AutoCAD Map 3D GIS to a comprehensive geographic information system called Utility Network Model (GIS-UNM). InnPower is among the first utilities in Canada to complete this upgrade. The new GIS-UNM enables bi-directional information flow between SCADA and the GIS and will enable InnPower to perform real-time spatial analysis such as circuit tracing and heat maps. Transitioning to this dynamic, robust, and integrated spatial database will improve the overall business intelligence, decision making process and operational optimization throughout the organization.
- **Distribution Automation and Modernization:** InnPower's plans to automate more of its network over the forecast period will also enable InnPower to use FLISR to have the system automatically generate a list of switching orders and automatically execute them. This is a fundamental concept of a self-healing network, which helps to reduce the size and duration of outages.
- **Radio communication for Protection and Control (SEL-3031):** The SEL-23031 radio communication has the ability to block an upstream protection device to potentially reduce outage interruptions and outage duration. This technology allows for local restoration before locking the entire feeder, reduces the potential scale of an outage and protects upstream equipment stress during the fault.

The above noted investments will help prepare InnPower for a future integration with an advanced distribution management system (ADMS) and eventually a Distributed Energy Resource Management System (DERMS). Although InnPower is not planning to have a fully implemented and integrated ADMS/DERMS system within the next five years, the future implementation of these systems will be

key to managing dynamic power flow in the distribution system and future facilitation of transactional electricity markets at the LDC level over time.

Consideration of Traditional Planning Needs

A distributor should also integrate traditional planning needs such as load growth, asset condition and reliability.

As previously explained in Section 5.3.1, traditional planning needs, including load growth, asset condition, and reliability are key inputs considered as part of InnPower's AM processes.

InnPower undertakes load studies to identify areas that may require investments to accommodate required capacity. Load growth is a direct input into InnPower's planning for System Access and System Service type projects. Load growth is also a key input into the regional planning process (detailed in Section 5.2.2.4) which helps to identify future requirements (both wires and non-wires) to accommodate load growth. As noted previously in Section 5.3.2.1, InnPower has experienced a significant level of growth over the historical period and this trend is expected to continue over the forecast period and beyond.

Asset condition and reliability data are key inputs considered by InnPower when identifying, selecting, and prioritizing System Renewal expenditures. Through a recently completed ACA exercise, several critical power supply infrastructure components employed at DS, OH lines and UG distribution system have been determined to be in "fair," "poor," or "very poor" operating condition. In the absence of investments into asset renewal, the existing infrastructure presents high risk of failure in service, affecting supply system reliability and public safety.

However, renewal and replacement of all infrastructure components determined to be in "fair," "poor," or "very poor" condition during the next five years would be difficult to manage through InnPower's resources and it would lead to unaffordable increase in retail rates. Given that the top two customer priorities correspond to "*Affordable cost of electricity*" and "*Maintaining and upgrading equipment to ensure a safe and reliable electricity supply,*" InnPower's challenge is to seek an optimized balance of these generally opposing factors. Therefore, in preparing this DSP, InnPower has focused on prioritizing the investments into renewal of the most critical infrastructure components to achieve the balance required between keeping the power supply reliability from degrading while maintaining the electricity distribution rates at affordable levels.

Overall Capital Expenditures

A distributor must not only provide information to justify each individual investment, but also the total amount of its proposed capital expenditures. A distributor should provide context on how its overall capital expenditures over the next five years, as a whole, will achieve the distributor's objectives. Particularly, a distributor should comment on lumpy investment years and rate impacts of capital investments in the long-term.

Capital expenditure trends over the 2017 to 2028 period, for net capital expenditures and underlying investment categories, both including and excluding the BATU and TS Projects, are shown in Figure 5.4-21 and Figure 5.4-22, respectively.

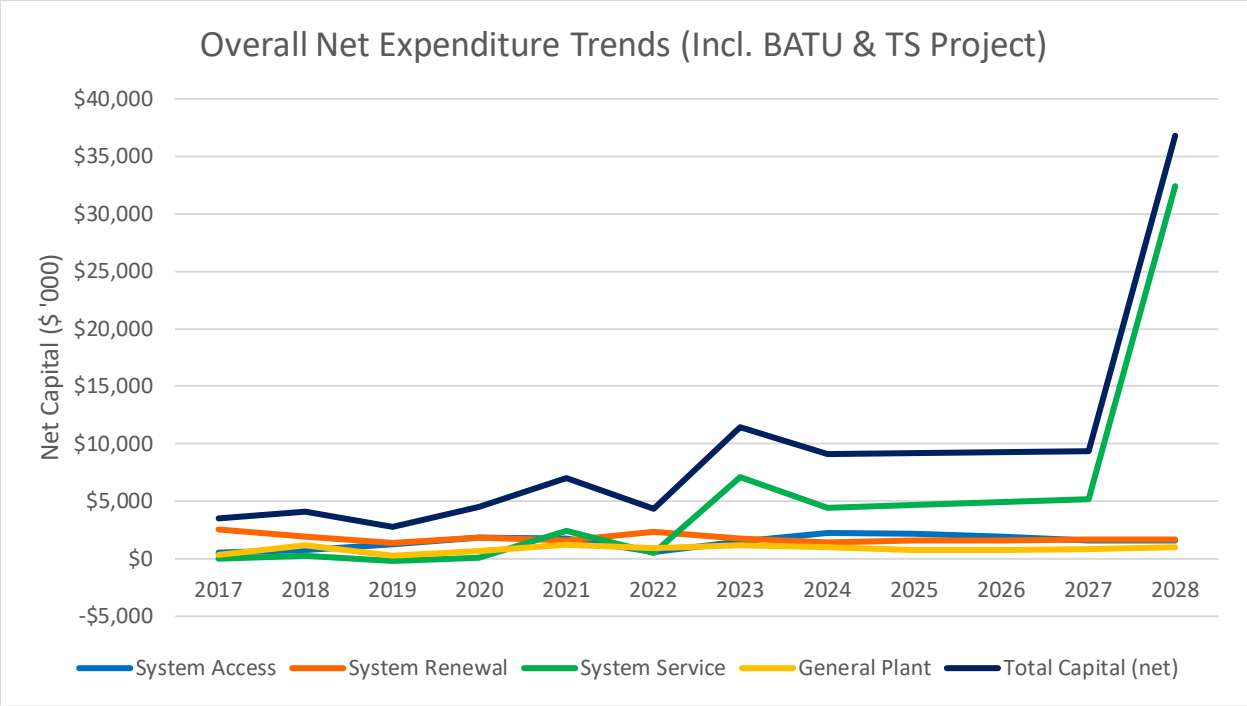


Figure 5.4-21: Overall Net Capital Expenditure Trends [Incl. BATU & TS Project]

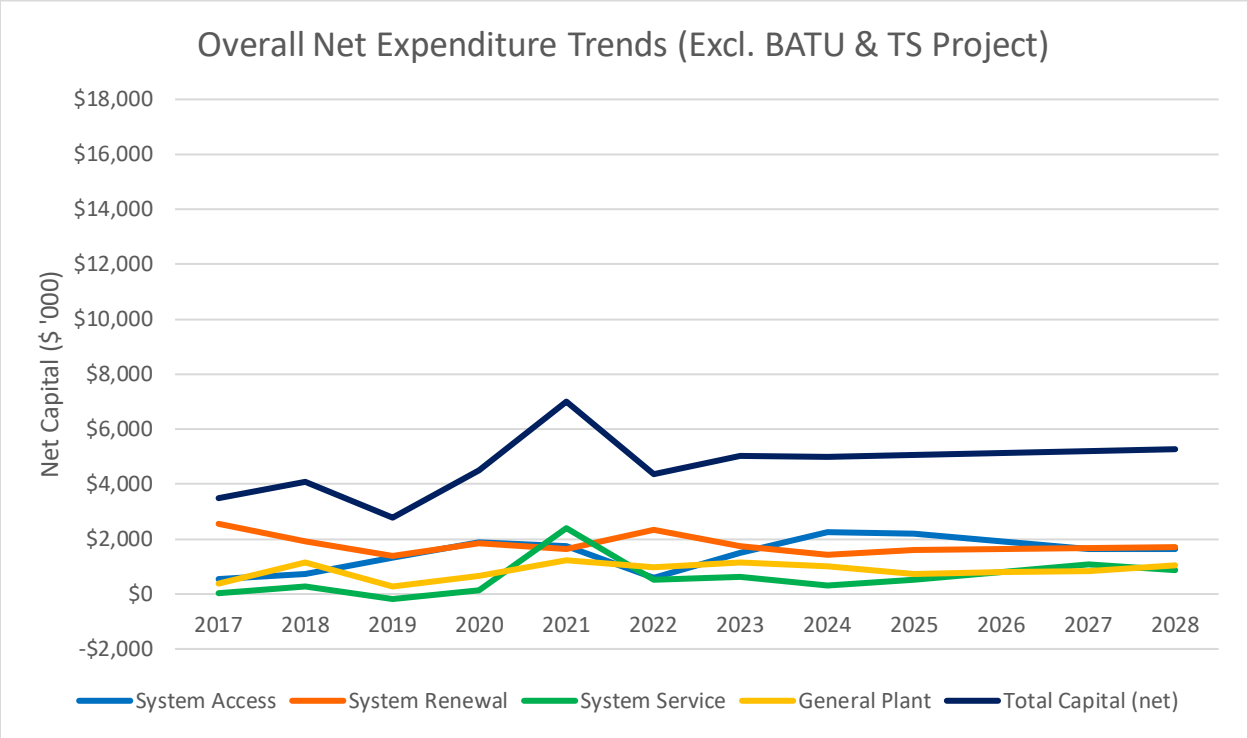


Figure 5.4-22: Overall Net Capital Expenditure Trends [Excl. BATU & TS Project]

When excluding the BATU and TS Project costs, InnPower's forecast net capital expenditures are expected to be slightly above historical costs (except for in year 2021) but remain relatively stable from 2023 to 2028.

The jump in year 2021 is driven by the Innisfil DS Rehabilitation. The drop in 2022 is primarily due to persisting supply chain issues in 2022. As supply chain issues continue to be mitigated in 2023, InnPower plans to catch up on the System Renewal projects, thereby explaining the jump in overall net expenditures in 2023.

As detailed in Section 5.4.1.3, the overall increase relative to historicals is driven by an increase in System Access to accommodate known customer growth areas in InnPower's service territory, continued investments in System Renewal to maintain and upgrade equipment to ensure a safe and reliable electricity supply, increase in System Service to address rehabilitation works needed to accommodate increased capacity needs and costs to replace/rehabilitate EOL equipment such as power transformers, and an increase in General Plant to maintain and upgrade InnPower's fleet, IT, buildings, tools and equipment in order to continue serving InnPower's growing customer base.

Over the forecast period, InnPower's capital expenditures are designed to achieve the four performance outcomes established by the OEB, while also adhering to InnPower's established AM Objectives set out in Section 5.3.1.1. This includes continuing to deliver safe, reliable, and affordable power, while also accommodating the expected load growth in InnPower's service territory.

5.4.2.1 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2A of the Filing Requirements for Electricity Distribution Rate Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g.: unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project/program should be proportional to the materiality of the investment.

For this Application, InnPower's materiality threshold is $73,000. Using the prioritization process previously detailed in Section 5.3.1.3, InnPower has ranked and prioritized its material investments planned in the Test Year (2024). Table 5.4-32 presents the prioritized list of material projects and programs that have been budgeted in 2024 with their associated prioritization scores. The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 5.4-33.

For each of these projects/programs, a detailed write-up, highlighting the drivers, justification, and analysis, is provided in Appendix A. The new TS Project is excluded from this list given that the costs associated with this project will remain in WIP and be addressed in InnPower's next rebasing application.

Table 5.4-32: Prioritized List of Material Capital Investments during the 2024 Test Year

Investment Category	Program/Project Name	Priority Score [1]	Status	2024 Planned Expenditure ($ '000)
System Access	(IPCSA) 100% Recoverable [2]	n/a	Budgeted	0
System Access	(IPCSA) Subdivisions	n/a	Budgeted	663
System Access	(IPCSA02) Road Authority	n/a	Budgeted	1,087
System Access	(IPCSA05) Metering	n/a	Budgeted	500
System Renewal	(IPCSR01) Capital Trouble Calls and Emerging Projects	1,269.86	Budgeted	358
System Service	(IPCSS17) BATU	1,254.14	Budgeted	4,120
System Service	(IPCSS12) Station Rehab [3]	1,192.74	Budgeted	0
System Renewal	(IPCSR04) Reclosure Replacement Program	473.30	Budgeted	200
System Renewal	(IPCSR02) Transformer Replacement Program	457.62	Budgeted	157
System Service	(IPCSS24) Normal Open Point Switch Installation	404.83	Budgeted	221
System Renewal	(IPCSR06) Switchgear Replacement Program	373.23	Budgeted	106
System Renewal	(IPCSR03) Pole Replacement Program	335.64	Budgeted	363
General Plant	(IPCGP12) Fleet and Single Bucket Truck	187.46	Budgeted	470
System Renewal	(IPCSR05) Switch Replacement Program	181.90	Budgeted	166
General Plant	(IPCGP01) IT Hardware	166.31	Budgeted	194
General Plant	(IPCGP02) IT Software	166.31	Budgeted	125
General Plant	(IPCGP10) Tools, Shop, and Garage Equipment	124.59	Budgeted	83
System Service	(IPCSS08) Communication Improvement	64.91	Budgeted	78
General Plant	(IPCGP04) Building and Fixtures	27.17	Budgeted	75

[1] Projects with priority ranked as n/a are considered top priority as these are non-discretionary (i.e.: customer/external driven).

[2] The gross cost for the 100% Recoverable program is $17.8M but this is 100% recoverable.

[3] The gross cost for the Station Rehab program is $3.1M but this is 100% recoverable.

Table 5.4-33: Prioritizing Matrix for Test Year Projects over the Materiality Threshold

Project / Program	Ensuring Public & Worker Safety		Meeting Legislative Constraints		Accommodating Organic Load Growth		Managing Costs		Maintaining System Reliability		Mitigating Environmental Risk		Priority Score
	Weight: 1.25		Weight: 1.00		Weight: 0.25		Weight: 0.50		Weight: 0.75		Weight: 1.00		
	L	C	L	C	L	C	L	C	L	C	L	C	
(IPCSA) 100% Recoverable	Ranked as top priority as these are non-discretionary (i.e.: Customer/Third Party Driven)												n/a
(IPCSA) Subdivisions													n/a
(IPCSA02) Road Authority													n/a
(IPCSA05) Metering													n/a
(IPCSR01) Capital Trouble Calls and Emerging Projects	9.0	54.6	2.5	2.7	5.0	2.7	5.0	7.4	9.0	20.1	9.0	54.6	1,269.9
(IPCSS17) BATU	9.0	54.6	7.5	2.7	9.0	54.6	7.5	7.4	9.0	54.6	5.0	20.1	1,254.1
(IPCSS12) Station Rehab	7.5	54.6	7.5	2.7	9.0	54.6	5.0	7.4	9.0	54.6	7.5	20.1	1,192.7
(IPCSR04) Reclosure Replacement Program	7.5	20.1	2.5	1.0	7.5	2.7	7.5	20.1	9.0	20.1	9.0	7.4	473.3
(IPCSR02) Transformer Replacement Program	9.0	20.1	9.0	2.7	5.0	7.4	5.0	7.4	7.5	20.1	9.0	7.4	457.6
(IPCSS24) Normal Open Point Switch Installation	7.5	20.1	2.5	1.0	2.5	1.0	7.5	20.1	9.0	20.1	2.5	1.0	404.8
(IPCSR06) Switchgear Replacement Program	7.5	20.1	2.5	2.7	5.0	1.0	7.5	7.4	9.0	20.1	5.0	2.7	373.2
(IPCSR03) Pole Replacement Program	9.0	20.1	2.5	1.0	5.0	2.7	5.0	2.7	7.5	7.4	7.5	7.4	335.6
(IPCGP12) Fleet & Single Bucket Truck	7.5	7.4	1.0	1.0	7.5	2.7	5.0	2.7	9.0	7.4	7.5	7.4	187.5
(IPCSR05) Switch Replacement Program	9.0	7.4	2.5	1.0	7.5	2.7	7.5	7.4	9.0	7.4	5.0	2.7	181.9
(IPCGP01) IT Hardware	5.0	7.4	7.5	7.4	7.5	7.4	5.0	2.7	7.5	7.4	2.5	1.0	166.3
(IPCGP02) IT Software	5.0	7.4	7.5	7.4	7.5	7.4	5.0	2.7	7.5	7.4	2.5	1.0	166.3

Project / Program	Ensuring Public & Worker Safety		Meeting Legislative Constraints		Accommodating Organic Load Growth		Managing Costs		Maintaining System Reliability		Mitigating Environmental Risk		Priority Score
	Weight: 1.25		Weight: 1.00		Weight: 0.25		Weight: 0.50		Weight: 0.75		Weight: 1.00		
	L	C	L	C	L	C	L	C	L	C	L	C	
(IPCGP10) Tools, Shop & Garage Equipment	7.5	7.4	5.0	1.0	5.0	1.0	5.1	1.0	7.5	7.4	5.0	1.0	124.6
(IPCSS08) Communication Improvement	2.5	1.0	7.5	2.7	2.5	1.0	7.5	2.7	5.0	2.7	7.5	2.7	64.9
(IPCGP04) Building & Fixtures	7.5	1.0	5.0	1.0	1.0	1.0	5.0	2.7	1.0	1.0	5.0	1.0	27.2

Note 1: "L" and "C" in the above table correspond to Likelihood and Consequence.
Note 2: The Priority Score is the sum of the products of Likelihood, Consequence and Weight associated with each AM objective.

Project Deferrals

In order to align InnPower's budget envelopes with customer expectations, decisions were made to defer, reduce pacing, or eliminate a number of scoped projects and program budgets over the forecast period. This includes reduced pacing of Hardware and Engineering IT investments, switch commissioning, and installation of fault indicators and the deferral of a bucket truck purchase in 2028. InnPower has been prudent in its overall forecast plan balancing the priorities of customers as identified from the customer survey of having "Affordable cost of electricity" (as selected by 92.67% of the respondents) and "Maintaining and upgrading equipment to ensure a safe and reliable electricity supply" (as selected by 80.00% of the respondents). In order to balance these priorities, InnPower has taken approach to reduce or defer some capital projects.

Table 5.4-34 lists the projects and programs budgets which have been reduced or deferred.

Table 5.4-34: Projects and Programs Deferrals

Project / Program Name	Status	Deferred Cost & Timing ($ '000)					Total Deferred Budgets ($ '000)
		2024	2025	2026	2027	2028	
(IPCGP01) IT Hardware	Deferred	106	-	-	-	-	106
(IPCSS07) 44kV Switch Commissioning	Deferred	-	144	158	-	-	302
(IPCSS05) 27.6kV OH Dist Fault Indicators	Deferred	-	59	65	-	-	124
(IPCSS06) 44kV OH Dist Fault Indicators	Deferred	-	57	63	-	-	120
(IPCGP06) Engineering IT	Deferred	-	80	-	-	-	80
(IPCGP20) Bucket Truck Purchase	Deferred	-	-	-	-	1,000	1,000
Total Annual Deferrals		**106**	**340**	**286**	**-**	**1,000**	**1,732**



Appendix A

Material Narratives

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This capital program is comprised of an ongoing business requirement to replace critical IT Hardware, including end user computers, network infrastructure and investments to comply with new cyber security frameworks to ensure the security of InnPower's IT infrastructure framework. IT hardware is the backbone of InnPower's ability to manage its operations safely and efficiently on a 24/7 basis. InnPower utilizes a 5-year lifecycle for IT hardware which is based on IT hardware industry best practices.

InnPower is currently undertaking an audit process to comprehensively understand the status of its IT hardware, as well as enable InnPower to develop a more detailed approach to meet its IT demands. This audit and plan will be completed by Q4 2023 and will be used to refine InnPower's IT investment plan. In addition, InnPower is undertaking a restructure of its IT department and IT infrastructure. As part of this restructure, InnPower will be implementing new comprehensive Cyber Security measures in addition to preparing for the completion of the Cyber Security Framework. InnPower's IT hardware program will include, but is not limited to:

a. Upgrades to network infrastructure, including additional storage and replacement, cyber security enhancements and redundancy for backup /disaster recovery;
b. Updating server infrastructure;
c. Replacing end of life computer hardware, including laptops and monitors, anticipated for approximately at least 15-20 users in 2024;
d. Implementing Hotelling stations at 7251 Yonge Street to maximize efficiency;
e. Purchasing new computer hardware for new hires; and
f. Staff training and education.

By implementing these programs InnPower will be positioned to continue to provide reliability service to its customers, reduce enterprise risk associated with end-of-life or high-risk IT infrastructure, and comply with the latest cyber security framework requirements. InnPower's IT hardware spend is increasing when compared to the historical period, but this is mainly driven by an increased number of assets that are or will reach end of life, increased growth of employees, and the investments required to comply with the enhanced cyber security requirements. InnPower will continually assess, review and adjust its investment plans as required.

2. Timing

i. Start Date: The timing of replacements and additions of hardware is driven by InnPower's lifecycle program, new requirements, and employee growth, with investments beginning in the test year.

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: Key factors that affect timing are:

- equipment failure,
- regulatory requirements,
- staff availability,
- other projects taking higher priority,
- supply chain constraints with respect to availability of IT equipment, and
- ongoing cyber security requirements.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	135	46	45	136	25	85	80	194	199	204	214	219
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	135	46	45	136	25	85	80	194	199	204	214	219

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Ongoing investments are made into InnPower's IT hardware program to support the efficient and effective operation of InnPower's IT infrastructure network 24/7. Historical costs for the 2017-2022 period are reflected in Section A3. Investments in IT hardware compared to historical expenditure are expected to increase due to the need to keep up with increased technological and cyber security threats in an evolving space, as well as an increased number of assets reaching end of life and an increase in the number of new employees. Procurement and manufacturing costs for key components associated with IT hardware have also increased leading to higher estimates by InnPower for this program when compared to historical expenditure.

6. Investment Priority

This investment priority was scored 166.31. Prioritization for the selection of assets is based on specific business needs for each project or to meet the needs of each individual employee. Investments in this program ensure that the upgrades keep up with the

technology and cyber security trends. These investments will maintain robust IT systems and cyber security protocols which ultimately contribute to overall reliability. The evolution of a hybrid work environment has led to shifting priorities for the deployment of IT hardware to support InnPower's operations and is a key factor in prioritizing hardware assets for replacement or upgrade.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

InnPower considered the following alternatives:

i. **Do nothing:** Doing nothing subjects InnPower to a risk of cybersecurity incidents and having unsupported obsolete hardware which would ultimately impact company operations and disaster recovery, making this option not viable.

ii. **Carry out the proposed pacing of investments:** This option allows InnPower to implement more viable redundancies for disaster recovery. This option also entails the upgrading of the network infrastructure to replace outdated devices to ensure continued reliability while replacing outdated devices to improve cyber security and overall productivity. Hence, this is the preferred option.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Hardware infrastructure is treated as a strategic asset. This infrastructure is utilized as the primary staff productivity tool. It allows the continued 24/7 operation of its network. It is used to maintain and

Primary Criteria for Evaluating Investments	Investment Alignment
	deliver timely services to customers; improve staff productivity; effectively manage total cost of PC ownership; and support investments in new applications, infrastructure, business capabilities and cyber security. InnPower utilizes IT best practices to minimize space, energy costs and to enhance cyber security in the planning process (i.e., virtual environments). InnPower utilizes replaced assets, where applicable, for disaster recovery purposes saving costs. *
Customer Value	InnPower's ability to provide services to its customers relies heavily on Information Technology (IT) with hardware and cyber security being a critical component. Maintaining adequate hardware and security protocols provides the corporation and staff with the tools required to provide timely services to its customers. It allows InnPower to ensure that it maintains it's obligation to provide infrastructure cyber security to protect the integrity of the services provided to customers and the protection of their privacy in providing those services.
Reliability	Maintaining robust IT systems and cyber security protocols will contribute to reliability. Security recommendations from external IT audits (i.e., firewalls, security appliances, and security monitoring hardware) will improve the functionality of these systems. In addition, InnPower is developing an offsite disaster recovery environment in the event of failure or disaster for the replacement of failed equipment.
Safety	Maintaining network infrastructure is crucial to the safety of the public and employees. Continued improvements to these systems are prudent in maintaining safety through the use of remote administration and visibility of the systems.

***** ***InnPower utilizes best management practices to determine if replaced assets can be used for Disaster recovery or other business requirements as needed.***

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower IT hardware is treated as a strategic asset because it is a key asset that staff uses to allow for the reliable and safe network operation 24/7.

InnPower maintains its hardware lifecycle management processes utilizing a refresh cycle to a maximum of 5 years, in order to: deliver, maintain and improve services to customers; to improve staff productivity; to effectively manage total cost of ownership; and to support investments in new applications, infrastructure, and business capabilities.

Maintaining a consistent IT hardware lifecycle refresh program allows InnPower to migrate to new applications without a need to make large one-time investments that are required to meet the minimum operating requirements of new applications.

i. Main Driver*:* Operational effectiveness and efficiency - By upgrading/replacing its IT infrastructure network and associated hardware accessories, InnPower will be able to carry out its operations as efficiently and safely as possible, catering to customer expectations. InnPower ensures that cost controls are in place to limit rate increases on ratepayers. InnPower is undertaking an audit of its IT hardware and the outputs of this will be used to optimize and prioritize future investments.

ii. Secondary Drivers*:* New Technology and Cyber Security - remaining up to date with new technologies and cyber security requirements is critical in ensuring InnPower maintains safe and reliable hardware for staff and contractors to perform their jobs competently.

iii. Information Used to Justify the Investment*:* InnPower's IT hardware refresh policy is for a five-year lifecycle refresh. InnPower tracks hardware assets to facilitate replacements as required to maintain the defined lifecycle. In addition, InnPower is undertaking an audit of its IT hardware, which will be used to help refine its plan for future years. Additionally, InnPower monitors and tracks the latest cyber security requirements, and identifies investments required to enable it to comply with these requirements in a timely manner.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice*:* InnPower adheres to industry standard practice of managing IT Hardware assets on a 5-year lifecycle. InnPower utilizes best management practices to determine whether replaced hardware assets can be used for Disaster recovery or other business requirements as needed. IT hardware is treated as a strategic asset. Additions, replacements, and upgrades of IT hardware comply with InnPower's standards, cyber security requirements, and InnPower's evolving needs.

ii. Cost-Benefit Analysis: Cost analysis is considered for all hardware purchases following corporate purchasing policies. InnPower utilizes best management practices to determine if replaced assets can be used for Disaster recovery or other business requirements as needed.

iii. Historical Investments & Outcomes Observed*:* Historical costs are reflected in Section A3 of this document. Historical investments in IT hardware have supported 24/7 operations and have minimized the impact of Cyber incidents. Historical investments in this program have also enhanced customer experience, increased connectivity speed, and enabled a smooth transition to a hybrid work setting.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management:

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation:

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This capital program is comprised of an ongoing business requirement to add and/or upgrade end user and network software. End-user software are internal applications that support InnPower operations. Network software supports InnPower's ability to operate its distribution network.

IT software supports multiple functions within InnPower to allow the distributor to provide reliable and safe power to its customers. IT software includes Customer Information Systems (CIS), the customer portal, security applications, regulatory support (such as the Green button initiative, which allows customers across our service territory to access information on how they consume energy at their home or business) , the internal InnPower intranet, human resources software, financial systems and IT systems to support physical and cyber security.

InnPower is undertaking a restructuring of it's IT department and IT infrastructure. As part of this restructure, InnPower will be implementing new comprehensive Cyber Security programs including, but not limited to, updating servers, software, staff training and education, offsite disaster recovery, protocols, and procedures. By implementing these programs InnPower will be positioned to continue to provide reliable service to its customers and reduce enterprise risk associated with end of life or high-risk IT infrastructure.

InnPower will continue to utilize a 3-year lifecycle for IT software, when appropriate, and has identified applications that require updates, upgrades, or replacement in this distribution system plan. The trigger for IT software lifecycle is primarily dictated by software providers, licensing terms of agreement and functionality of current versions of software used by InnPower.

2. Timing

i. Start Date: The timing of replacements and additions of software is driven by InnPower's lifecycle program, new software requirements and employee growth.

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: Key factors that affect timing include:

- end of life software;
- regulatory requirements;

- availability of software upgrades at end of life, and
- ongoing cyber security requirements including security and privacy.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	51	14	61	118	60	85	126	125	128	131	135	138
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	51	14	61	118	60	85	126	125	128	131	135	138

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

As each software application is upgraded or capital expenditure incurred based on the terms of that end user or network solution, comparative historical expenditures are difficult to define per software solution. InnPower anticipates an increase in software upgrade and replacement cost, as reflected in Section A3, due to increased licensing fees, the transition to subscription-based cost models (e.g., Microsoft Office billed monthly), and increased cyber security requirements.

The increased costs associated with software solutions are parallel to the anticipated increase in cost associated with InnPower's IT hardware. The transition to hybrid work has increased the need for security and risk mitigation with software solutions.

6. Investment Priority

This investment priority was scored 166.31. Prioritization for the selection of assets is based on specific business needs for each project or to meet the needs of each individual employee. Investments in this program ensure that the upgrades keep up with the technology trends and cyber security requirements. These investments will allow InnPower to maintain robust IT systems and cyber security protocols which ultimately contribute to overall reliability.

The evolution of a hybrid work environment has led to shifting priorities for the deployment of IT software to support InnPower operations and is a key factor in prioritizing software for replacement or upgrade.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

InnPower considered the following alternatives:

i. **Do nothing:** Doing nothing subjects InnPower to a risk of cybersecurity incidents and having unsupported obsolete software which would ultimately impact company operations and disaster recovery, making this option not viable.

ii. **Carry out the proposed pacing of investments:** This option allows InnPower to implement more viable redundancies for disaster recovery. This option also entails upgrading of networking infrastructure to replace outdated software to ensure continued reliability while also replacing outdated software to improve cyber security and overall productivity. This is the preferred option.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Software is treated as a strategic asset. The Customer information System (CIS) software is the backbone of all customer data and is used for billing electricity. Enhancements and upgrades are required to maintain productivity and to benefit from new software capabilities. Automation software is implemented to streamline existing and new processes allowing better productivity and customer service. Network security is also a high priority; software upgrades and additions play an important role in maintaining data integrity, security, and privacy.

Customer Value	InnPower's ability to provide services to its customers relies heavily on Information Technology (IT) with software being a critical component. Maintaining adequate software provides the corporation and staff the tools to provide timely services to customers. Self-serve customer portals, green button solutions and digital services provide value and convenience to InnPower customers. Security software, as required, is integral in maintaining cyber security and privacy requirements.
Reliability	Maintaining robust IT systems will contribute to reliability.
Safety	Maintaining IT software is crucial to the safety of public and employees. Continued improvements to these systems are prudent in maintaining safety through the use of remote administration and visibility of the distribution systems.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

Software is treated as a strategic asset. Enhancements and upgrades are required to maintain productivity and to benefit from new software capabilities. Automation software is implemented to streamline existing and new processes allowing better productivity and customer service. Network security is a high priority; software upgrades and additions play an important role in maintaining data integrity and privacy. A key input driving InnPower's investment needs is the requirements of the cyber security framework. InnPower continuously monitors the latest requirements and adjusts its investment plans accordingly to enable compliance. In addition, vendor operating, and network software are continuously upgrading their versions which also factors into driving the need to invest accordingly.

i. Main Driver*:* Operational effectiveness and efficiency - By upgrading/replacing its IT end user and network software, InnPower will be able to carry out its operations as efficiently and safely as possible, catering to customer expectations. InnPower ensures that cost controls are in place to limit rate increases on ratepayers. InnPower is undertaking an audit of its IT software and the outputs of this will be used to optimize and prioritize future investments.

ii. Secondary Drivers: New Technology and Cyber Security - remaining up to date with new technologies and cyber security requirements is critical in ensuring

InnPower maintains safe and reliable hardware for staff and contractors to perform their jobs competently.

iii. Information Used to Justify the Investment*:* InnPower's IT software refresh policy is for a three-year lifecycle refresh. InnPower tracks software to facilitate replacements as required to maintain the defined lifecycle. In addition, InnPower is undertaking an audit of its IT software, which will be used to help refine its plan for future years. Additionally, InnPower monitors and tracks the latest cyber security requirements and vendor software upgrades, and identifies investments required to enable it to comply with these requirements in a timely manner.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower adheres to an IT software industry standard practice of managing its software a 3-year lifecycle to ensure vendor support is available, decrease the likelihood of failure, comply with the latest standards, meet business needs, and ensure cyber security threats are mitigated.

ii. Cost-Benefit Analysis*:* A cost benefit analysis is considered for all IT projects. A key driver for IT software projects is mitigating enterprise risk with data on company servers.

iii. Historical Investments & Outcomes Observed: Historical costs for software solutions are variable depending on the solution but have increased over time with the need to support emerging technologies and the transition to a hybrid workforce. Additionally, historical investments have supported 24/7 operations, minimized the impact of Cyber incidents, and enhanced customer experience.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing

technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP04 – BUILDING & FIXTURES

INVESTMENT CATEGORY:

GENERAL PLANT

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower's main operations building and yard, located at 7251 Yonge Street in Innisfil Ontario, represents the critical backbone of InnPower's 24/7 operations as it houses the office and field staff who undertake daily operations, customer billing, engineering & planning, field services and operations within the control room. This program entails general repairs, replacements, and upgrades within these facilities, which includes security improvements, asset replacements (e.g., windows, water heater, etc.), installation of power outlets and safety railings, and other general improvements. Without investments in these facilities, there will a be detrimental impact on InnPower's operations that could affect both the safety of staff, as well as have an indirect impact on the reliability of the system and the ability to deliver services cost effectively.

The work planned for 2024 predominantly involves a security system upgrade with the remaining budget allocated towards other general repairs, replacements, and upgrades within the facility in accordance with InnPower's preventative maintenance and inspection programs.

- **Security System Upgrades:** Investments to improve InnPower's existing security systems with remote access to the facility and access to control solutions will positively impact the health and safety of InnPower's day-to-day business operations by monitoring misconducts, safety practices, and break-ins. Planned investments into the security system constitute approximately 60% of the planned budget in the 2024 Test Year.
- **Other General Replacements, Repairs and Upgrades:** The remaining Test Year budget, as well as forecast budgets, are allocated towards ad-hoc works needed to support the safe and reliable continuation of InnPower's operations. This can include a variety of works such as building improvements to accommodate increased staffing needs (e.g., building extension, additional locker spaces, etc.), general asset repairs, replacements and upgrades (e.g., plumbing, garage doors and windows, gate, generator, heating and cooling, etc.) as identified by InnPower's preventative inspection and maintenance activities, reactive replacements due to premature failure of any building assets, and addressing any other on-going requirements to maintain the upkeep and safe working condition at InnPower's facilities.

Investments under this program vary year to year based on specific needs identified.

2. Timing

i. Start Date: January 2024

ii. In-Service Date: 2024-2028

iii. Key factors that may affect timing: The below listed factors can impact the timing of the proposed investments:

- Resource constraints;
- Supply chain issues;
- Project prioritization; and
- Overall budget constraints.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	71	196	39	76	44	144	75	75	77	79	81	83
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	71	196	39	76	44	144	75	75	77	79	81	83

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Ongoing investments are made into InnPower's main operations building and yard to support 24/7 operations. Historical costs for the 2017-2022 period are reflected in Section A3. Historical costs have varied year over year in accordance with specific needs identified and works undertaken.

The table below provides a summary of work that was completed as part of this program over the historical period.

Table 2: Summary of Work Completed Over Historical Period

Year	Summary of Work Completed
2017	Spend in this year was primarily on fire separators between InnPower facilities and adjoining daycare along with signage for InnPower buildings.
2018	Spend in this year was a result of adjustments from the Auditor along with architectural fees for LEEDs certification and building site inspections.

Year	Summary of Work Completed
2019	Spend in this year was the result of shelving and wire rack installation in the InnPower Stores department.
2020	Spend in this year was primarily attributed to electrical fees for yard lighting. The remaining costs included glass partition for customer service, replacement of compressor and electrical components for air conditioner and miscellaneous electrical work.
2021	Spend in this year was attributed to excavations, concrete sidewalk removal and replacement and emergency lights installation.
2022	Spend this year was due to electrical fees to get power to the yard, and safety rail installation near HVAC equipment including a new HVAC vent motor and new humidifier.

Due to the nature of the projects within this program and the fact that works are completed on an as-needed basis depending on the need, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.

6. Investment Priority

This is a relatively low priority investment that was scored 27.17. Direct impacts in the areas of customer outages and customer service levels would be minimal relative to other projects, and most of the needs identified to not constitute an immediate material safety risk. However, if left unaddressed for too long, there would a be detrimental impact on InnPower's operations that could affect both the safety of staff, as well as have an indirect impact on the reliability of the system and the ability to effectively deliver services, which could lead to the need for much more costly remedial solutions in the long term.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

InnPower considered the following alternatives:

i. **Do nothing:** Doing nothing is not a viable option. Without investing in the ongoing repair, replacement, and upgrades of InnPower's building and yard facilities, there is a risk that these facilities will not be fit for InnPower staff to carry out their jobs safely and efficiently.

ii. **Carry out the proposed pacing of investments:** This is the preferred option as it allows InnPower to continue investing in its operations building and yard facilities in order to support 24/7 operations. InnPower evaluates the identified needs to determine which are most critical to undertake and which can be monitored and pushed out to later years. Project-specific alternatives (e.g., run to fail vs. repair vs. replace like-for-like vs. upgrade with additional functionality) are considered on a case-by-case basis depending on the identified need.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

1. Efficiency, Customer Value, Reliability & Safety

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By investing in its facilities to keep them up to date, clean, safe, and secure, InnPower will ensure that staff can continue to work in a safe and comfortable environment which will enable the staff to maintain operational efficiency and support 24/7 operations.
Customer Value	An up to date, clean, and safe environment ensures that staff can undertake their work effectively and efficiently and deliver what customers need.
Reliability	Through these investments, there is no direct impact on reliability of the network in terms of planned outages. However, these facilities are crucial to support continued 24/7 operation and they also house equipment and materials that are used daily to help maintain the reliability of the system.
Safety	The repair, replacement, and upgrade of damaged, obsolete or end of life building assets help mitigate any catastrophic failure which may compromise the safety of employees and the public. This work also ensures that InnPower has a safe workspace and functioning building assets that meet the latest health and safety standards and regulations keeping its staff safe while carrying out their work activities.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: Non-System Physical Plant - The primary driver for this program is to renew and invest in InnPower's non-system physical plant. Within the context of this program, it is to invest in InnPower's facilities that house in-office & operations staff and equipment that is used for maintenance and operations.

ii. Secondary Drivers: System Maintenance Support – InnPower's main operations building, and yard also houses maintenance equipment and vehicles and provides space for the field staff to undertake repairs. By investing in these facilities and ensuring they are fit for purpose, InnPower is protecting the equipment stored which helps to ensure that they will work when needed.

iii. Information Used to Justify the Investment: InnPower tracks its building assets (e.g., plumbing and air, garage doors and windows, security system, gate, generator, heating, and cooling) through its preventative inspections and maintenance activities to identify and prioritize repairs, replacements and upgrades needed throughout the year. This information helps facilitate the general upkeep and adaptation of the existing building to improve safety, growth, and general use of the building.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice*:* To ensure that InnPower can deliver safe, reliable, and efficient service, it is fundamental that InnPower has the necessary foundations in place. It is accepted industry practice that utilities have office space to house staff from engineering to accounting to operations so customer needs can be met. In addition, it is important that field staff have the resources, tools, equipment, and space to carry out maintenance and capital projects. It is good practice for utilities to incur costs each year to maintain its operations building, yard, and storage areas. InnPower has carefully reviewed and planned what is required to be carried out to ensure it can still operate and delivery safe, reliable, and efficient service to its customers.

ii. Cost-Benefit Analysis: A request for proposal (RFP) process is conducted for InnPower's preventative maintenance programs to lock in rates for the term of the

contract. For any service required without a contract, InnPower gathers three (3) quotes to ensure the best value is obtained in terms of cost and delivery time. Project-specific alternatives are also evaluated on a case-by-case basis depending on the identified need, and cost analysis is considered following InnPower's corporate purchasing policies.

iii. Historical Investments & Outcomes Observed: Historical costs are indicated in Sections A3 and A5 of this document. Historical investments in buildings and fixtures have supported the 24/7 operations and have enabled InnPower field crews to carry-out maintenance activities in a safe, efficient, and cost-effective manner. Historical investments in this program have resulted in the ability for InnPower staff to continue to perform all its critical services, as well as investing in the upkeep of the building, and addressing health and safety defects that were identified. This has ensured the continued ability to operate 24/7 and deliver safe and reliable electricity supply to its customers.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP10 – TOOLS, SHOP & GARAGE EQUIPMENT

INVESTMENT CATEGORY:

GENERAL PLANT

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This program includes the purchase of various tools and small equipment necessary to carry out the operations and maintenance activities of the engineering, operations and stores departments. This includes but is not limited to specialized cutting tools, trailers for poles or reels of wire, and stores equipment to improve the operational efficiency of the field crew, lower operational costs, or reduce potential safety risks.

The program budget allows for the replacement of tools and equipment that have reached their end of typical useful life (e.g., due to deterioration, substandard performance, and/or functional inefficiencies), for the purchase of additional tools and equipment needed to serve InnPower's growing customer base, as well as for unplanned replacements of tools and equipment due to premature failure. Investments under this program vary year to year based on specific needs. Major expenditures planned for 2024 predominantly constitute general tool replacements that have reached their end of typical useful life (e.g., batteries, hydraulic tools, garage door fits, etc.), along with the replacement of an Automated External Defibrillator (AED).

2. Timing

i. Start Date: January 2024

ii. In-Service Date: 2024-2028

iii. Key factors that may affect timing: Key factors that influence the timing of these investments include:

- Supply chain issues;
- project prioritization, and
- overall budget constraints.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	5	0	29	18	75	53	79	83	85	87	89	91
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	5	0	29	18	75	53	79	83	85	87	89	91

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

InnPower periodically purchases or renews various tools and equipment that are used to carry out the operations and maintenance activities of the engineering, operations, and stores departments. Historical costs for the 2017-2022 period are reflected in Section A3. Historical costs have varied year over year in accordance with specific needs identified and have been impacted by other factors such as supply chain issues and budget reallocations to higher priority projects. The table below details a summary of work that was completed as part of this program over the historical period.

Table 2: Summary of Work Completed Over Historical Period

Year	Summary of Work Completed
2017	Purchase of air compressor, submersible pump, and hoses.
2018	Minimal purchases.
2019	Purchase of 27kV load break and accessories, pole climbing equipment (i.e., harness, rope lanyard, etc.) and equipment bags/pouches.
2020	Purchase of cable cutters, vertical bar storage, barricades, engineer drawings and miscellaneous small tools.
2021	Purchase of cable and pipe locator, laser rangefinder, grounding wire and miscellaneous small tools.
2022	Purchase of defibrillator, switch rack, hydraulic press, grounding block, batteries, grips, and miscellaneous small tools.

Due to the nature of the projects within this program and the fact that purchases are completed on an as-needed basis depending on the type of work required, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.

6. Investment Priority

This is a relatively lower priority investment that was scored 124.59. The tools and equipment proposed to be purchased are critical to InnPower being able to carry out their operations and maintenance activities. Although a deferral of investment now may not have immediate financial or reliability consequences, over time these would be expected to grow.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

InnPower considered the following options:

i. **Do nothing:** Doing nothing is not a viable option. This would impede InnPower's ability to carry out the necessary operations and maintenance activities of the engineering, operations and stores departments. Furthermore, it would put assets at risk of failure and expose customers to longer and more frequent outages in the event of preventable failures.

ii. **Carry out the proposed pacing of investments**: This is the preferred option as it allows InnPower to invest in the tools and equipment necessary to carry out the operations and maintenance activities of the engineering, operations, and stores departments. These investments will also enable improved operational efficiency of field crews, lower operational costs, and reduce potential safety risks. Project specific alternatives (e.g., do not replace vs. like-for-like replacement vs. upgrade with additional functionality) are considered on a case-by-case basis depending on the identified need, and a formal procurement process is followed to obtain three (3) quotes before making a purchase.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Having access to the proper tools and equipment in good working order allows field crews to perform their tasks in the most efficient manner.
Customer Value	By continuing to support daily operations and maintenance activities, these investments help to ensure performance measures targets are met including operational efficiency, reliability, and safety. The purchase of additional tools and equipment will

Primary Criteria for Evaluating Investments	Investment Alignment
	also enable line crews to serve InnPower's growing customer base.
Reliability	Continued investment in the proper tools and equipment ensures that the reliability of InnPower's system is maintained. Having access to the proper tools and equipment in good working order allows crews to perform their tasks in the most efficient manner, including operation and performing preventative maintenance to better assess the condition of its assets and eliminate or reduce the duration of the system interruption that would have been introduced had the asset failed. These investments also allow crews to respond to system interruptions faster and more efficiently, thus reducing the overall duration of system interruptions and improving reliability.
Safety	The purchase of proper tools and equipment help to reduce potential safety risks to InnPower staff. In some cases, the equipment being purchased is directly related to crew safety, such as the purchase of the new AED in the 2024 Test Year. Tools and equipment are also necessary for InnPower to carry out maintenance activities, the results of which help inform which assets need investment, including in need of immediate investment due to safety concerns.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: System Maintenance Support - The primary driver for this program is to improve its system maintenance support. The continued investment in various tools and equipment will ensure the continued safe, reliable and efficient operation of the grid and enable field crews to carry-out maintenance activities in the most efficient manner.

ii. Secondary Drivers: There are no secondary drivers for this program.

iii. Information Used to Justify the Investment: A range of factors including observations made during ongoing inspections and maintenance activities, input from staff, utility best practice, regulation, and recommendations from manufacturers are considered when identifying and justifying the need for

investments under this program. Project specific alternatives are considered on a case-by-case basis. Prior to purchase, InnPower goes through a formal procurement process, which involves seeking at least three (3) quotations from vendors. These quotes are reviewed prior to the purchase of tools and equipment to ensure that the best value is obtained.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: It is accepted industry practice that utilities invest in proper tools and equipment necessary to carry out operations and maintenance activities in a safe, efficient, and cost-effective manner. Continuous investment in proper tools and equipment is also required to avoid tool failure which would not allow crews to maintain the distribution system in a timely manner. Through investment in the proposed tools and equipment over the forecast period, InnPower will ensure that field crews have what they need to support daily operations and maintenance activities to better serve InnPower's growing customer base.

ii. Cost-Benefit Analysis: A request for proposal (RFP) process is conducted for InnPower's preventative maintenance programs to lock in rates for the term of the contract. For any service required without a contract, InnPower gathers three (3) quotes to ensure the best value is obtained in terms of cost and delivery time. Project-specific alternatives are also evaluated on a case-by-case basis depending on the identified need, and cost analysis is considered following InnPower's corporate purchasing policies.

iii. Historical Investments & Outcomes Observed: Historical costs are indicated in Sections A3 and A5 of this document. Historical investments in proper tools and equipment have supported daily operations and have enabled InnPower field crews to carry-out maintenance activities in a safe, efficient, and cost-effective manner.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. INNOVATION

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP12 – FLEET & SINGLE BUCKET TRUCK

INVESTMENT CATEGORY:

GENERAL PLANT

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower currently controls and manages 21 fleet vehicles, comprised of private vehicles, light trucks, heavy trucks, and trailers, as well as other miscellaneous equipment to support the system. InnPower's current fleet vehicles are listed in Table 1. InnPower leases two (2) out of the 21 vehicles listed below.

Table 1: InnPower Fleet List (as of December 21, 2022)

Year	Vehicle Type	Vehicle Number	Ownership
2010	Trailer	V401	Own
2010	Trailer	V404	Own
2010	Heavy Truck (Single Bucket Truck)	V302	Own
2010	Trailer	V402	Own
2011	Trailer	V403	Own
2011	Heavy Truck (Radial Boom Derrick)	V201	Own
2014	Private Passenger Vehicle	V99	Own
2014	Private Passenger Vehicle	V97	Own
2014	Private Passenger Vehicle	V98	Own
2015	Trailer	V405	Own
2016	Private Passenger Vehicle	V601	Own
2017	Heavy Truck (Single Bucket Truck)	V304	Own
2018	Private Passenger Vehicle	V083	Own
2018	Private Passenger Vehicle	V082	Own
2018	Private Passenger Vehicle	V081	Own
2018	Private Passenger Vehicle	V084	Own
2018	Light Truck	V102	Own
2018	Heavy Truck (Double Bucket Truck)	V303	Own
2021	Heavy Truck	V104	Lease
2021	Heavy Truck (Radial Boom Derrick)	V202	Own
2022	Heavy Truck	V103	Lease

Fleet vehicles must be maintained at an optimum level to ensure public and employee safety, to comply with laws and regulations, to keep repair costs at a minimum, and to support functional needs and performance requirements associated with executing maintenance and capital investment plans.

The 2024 Test Year budget includes the completion of the purchase of a new Category B Material Handling Aerial Device (MHAD) from Posi Plus (single bucket truck) to replace InnPower's existing single bucket truck (fleet vehicle V302) which has been in service

since 2010. As a result of supply chain issues, the procurement process for this new single bucket truck has already commenced and will span three (3) years: the chassis arrived in late 2022, the aerial component is planned to be installed in 2023, and the outfitting and final delivery will occur in year 2024. Since the new single bucket truck will be used and useful in year 2024, the budgeted amount in the 2024 Test Year corresponds to the full purchase price of the vehicle. The new bucket truck will provide extremely versatile functions for construction, maintenance and trouble call projects of all types. An example of a single bucket is shown in the following figure (note: every bucket truck is unique and customized, but this image provides an example of a vehicle that is similar to the single bucket truck used and to be purchased by InnPower).



Figure 1: Example of a Single Bucket Truck [1]

Beyond the 2024 Test Year, the forecast program budget will comprise a mix of end-of-life fleet replacements and additions based on staff growth to accommodate InnPower's growing customer base. The planned budget over the 2025 – 2028 period is assumed to address two (2) fleet vehicles on average per year with full outfitting.

2. TIMING

i. Start Date: January 2024
ii. In-Service Date: The new bucket truck will be used and useful in 2024. Other fleet investments will occur over the 2025-2028 period.
iii. Key factors that may affect timing: Key factors that affect timing include:
    - supply chain issues and the adherence of fleet suppliers to the delivery schedule. Large vehicles including bucket trucks are typically budgeted for

[1] **Image Reference:** Please note that this image has been extracted from the following URL: https://www.posiplus.com/en/aerial-devices/insulated-articulated-bucket-trucks/400-model.

and ordered at least one (1) year in advance of delivery due to the long lead times required by the manufacturers.
- project prioritization, and
- overall budget constraints.

3. Historical and Future Capital Expenditures

Table 2: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	15	573	0	19	658	46	476	470	200	200	200	200
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	15	573	0	19	658	46	476	470	200	200	200	200

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs for the 2017-2022 period are reflected in Section A3 above. Historical costs have varied year over year in accordance with specific needs identified and fleet works undertaken. Some of the larger jumps observed are explained below:

- **2018:** This cost is largely driven by the purchase of a new Altec Double Bucket Truck.
- **2021:** This cost is driven by the purchase of vehicles at the end of their lease for the following vehicles: V304, V102, V81, V82, V83 and V84. Due to supply chain issues, InnPower was at risk of not being able to replace the vehicles at the end of the lease, so the decision to purchase was made.
- **2023:** This cost includes the leasing of a small service truck to accommodate some of the small rural roads in InnPower's service area, to assist with low voltage work and reduce gas consumption required for scheduled customer appointments. This cost also includes the replacement/addition of general pool vehicles to accommodate additional staff through the leasing option. All fleet vehicle purchases are made in compliance with InnPower's procurement process. Quotations are obtained from manufacturers and this, along with historical costs, are used to estimate the costs of replacement. As noted above, InnPower is planning to finalize the purchase of the new bucket truck in 2024 to replace the existing single bucket truck V302. The cost of this replacement is $470,000. Although not a direct comparison, the Altec Double Bucket Truck purchased in 2018 was approximately $375,000. The observed cost differences can mostly be attributed to the different vehicle specifications, manufacturers, and the significant rise in the cost of goods and inflation in recent years.

6. Investment Priority

This is a medium priority investment that was scored 187.46. The need to replace the existing single bucket truck V302 in 2024 is based on the criteria established in InnPower's current Fleet Management Policy. V302 was initially put into service in 2010 and has been the most heavily used vehicle in the entire InnPower fleet since 2010. As of September 2021, this vehicle had accumulated approximately 240,000kms/3900hrs on the chassis and 4800hrs on the PTO (power take-off). As a result, V302 has been prioritized for replacement. Deferring this investment would result in increased maintenance and repair costs along with increased restoration time. Continuing to rely on V302 can also compromise employee and public safety and system reliability as vehicle reliability is expected to decrease, and thus V302 may not be available when needed (e.g., during system interruptions and outages). Non availability of V302 or vehicle down time can potentially impact capital or customer driven work timing.

Beyond this bucket truck replacement, continued investments in InnPower's fleet over the forecast period is needed to continue supporting business needs. Without proper fleet management, proactive and reactive work can fall behind thus increasing risks to safety and reliability and increasing costs.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

With every vehicle replacement, department needs are reviewed to determine the best option. The following alternatives were considered for the replacement of the current MHAD V302:

i. **Do nothing**: This option is not viable as doing nothing (i.e., retaining V302) will result in an increase in regular maintenance and repair costs and will not address the significant mileage accumulated on this vehicle. This option will also add risk to the operational efficiency of construction, restoration, and customer access to power and increases the risk of catastrophic failure which may threaten the safety of employees and the public. This alternative is not considered feasible since it will lead to an unexpected equipment failure, increased outage restoration times as well as increased maintenance costs and health and safety risk to line workers and the public.
ii. **Overhaul V302**: Overhauling the vehicle with new chassis would cost roughly half that of an entirely new MHAD and would not provide replacement of the boom, outriggers, major hydraulics, and Material Handler (jib). The maintenance and repair costs would therefore be expected to steadily increase over time as well as an increase to vehicle down time for repairs. The option to overhaul the chassis was projected to put the vehicle out of service for over a year with no replacement option. Therefore, this option is not recommended.
iii. **Leasing the vehicle**: InnPower considered whether a leasing model would be possible, however leased trucks were not an option at the time of purchase due to supply chain issues. As a result, this option was discarded.

iv. **Like-for-like replacement of V302**: Under this option, InnPower will undertake like-for-life replacement of the bucket truck in line with the fleet replacement considerations outlined in the Fleet Management Policy. By utilizing this approach, InnPower will ensure that it will have safe and reliable vehicles required to support system maintenance and capital investment activities. The following sub-alternatives were considered for the replacement of V302:

   a. **Sub-Alternative 1 – (Selected Option) Purchase of Posi Plus 400-46 MHAD:** Posi Plus is the only manufacturer of Insulated Aerial Devices that are both engineered and built in Canada. Owing to the technical benefits highlighted in Table 2 below, Posi Plus qualifies as the most suitable Aerial Device for Utilities across Canada and specifically within the province of Ontario. This was also the least cost option with a quoted purchase price of $414,000 plus applicable taxes. InnPower has selected this option.

   b. **Sub-Alternative 2 – Purchase of Altec AN50OC MHAD:** Along with Posi Plus, Altec is another prominent manufacturer of Material Handling Aerial Devices in the market. However, this MHAD would be engineered, built, and shipped from the US, and the quoted purchase price for this option was more expensive than the Posi Plus option (i.e., $447,250 plus applicable taxes). As a result, this option was discarded.

   c. **Sub-Alternative 3 – Purchase of Terex HR46 MHAD:** Terex is another prominent U.S.-based manufacturer of Material Handling Aerial Devices. However, for this option, the manufacturer noted significant supply chain constraints that would impact the availability and delivery schedule of the vehicle. As a result, this option was discarded.

The technical analysis of the above three options have been highlighted in **Error! Reference source not found.** below.

Table 3: MHAD Options Analysis

Options	Posi 400-46	Altec AN50OC	Terex HR46
Boom			
Classification	Category B	Standard - Cat C. Optional - Cat B	Standard - Cat C. Optional - Cat B
Upper Boom Shape	Rectangular	Circular	Rectangular
Lower Boom Articulations	120	105	120
Upper Boom Articulation	210	196	193
Working Height (ft)	51	48.3	50.5
Side Reach (ft)	37.8	32.1	36.6
Material Handling			
Platform rotation required to get close to the jib	90	120	120
Jib Shape	Rectangular	Circular	Rectangular
Capacity (lbs)	2000	1000	1500
Jib length (ft)	9	6	9

Rotation (degrees)	250 in all positions	180 in certain positions	
Rotate Under Load	Yes	Yes	Yes
Rotation in all boom positions	Yes	No	No
Extend/Retract under load	Yes. No restrictions	Yes. With load & boom position restrictions	Yes. With load and boom position restrictions
Winch rope capacity (lbs)	4000	1500	1500
Fiberglass guards	Installed all around jib	Installed in certain places	Installed all around jib
Hydraulic Handline	Yes	No	No
Hydraulics			
Exposed Hoses at Boom Tip	Internal. One set for jib/winch function	One set from bucket to boom. Plus, one Set from boom to jib	Internal. On set from boom to bucket controls
Hose Routing	Internal	Internal	Internal
System	Full-Pressure Hydraulic	Pilot Pressure	Full-Pressure Hydraulic
Outrigger Controls	Full-Pressure Hydraulic	Electric over Hydraulic	Full-Pressure Hydraulic
Lower Control Location	Lower Rear right of body under rotation	At turret in line with rotation	At turret in line with rotation
Miscellaneous			
Custom design	Yes	Yes, and factory-built option	Yes and/or Factory Built option
Platform steps and handrails	Standard. Large steps and sturdy handrails	Small steps and no handrail are standard	Small steps and no handrail are standard
Body Type	Fibreglass	Fibreglass	Fibreglass
Manufacturer	Custom. Protek Bodies Preferred	Altec	Custom
Company			
R&D Design	Canada	Southern USA	South Dakota
Built	Quebec, Canada Ontario, Canada	USA	USA

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 4: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Consistent management of InnPower's fleet will ensure that life cycle costs and risks of catastrophic failure remain low. Planned replacement of the fleet ensures that the field team is using the most efficient and reliable equipment possible while on the job. Unreliable fleet can negatively impact utility performance, such as reliability and employee productivity, and as vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs.
Customer Value	The replacement of end-of-life fleet vehicles will allow InnPower to maintain its ability to provide a timely, safe, and reliable service to customers. Having a safe and reliable fleet reduces operating and maintenance costs and mitigates the risk of work disruption and delays in customer service requests and/or outage response time to unplanned incidents, such as trouble calls and storm response, due to vehicle breakdown. The planned replacement of old and unreliable fleet also mitigates any catastrophic failure which may threaten the safety of employees and the public.
Reliability	The replacement of end-of-life fleet vehicles allows for the continued efficient day to day operations of the InnPower business. Having reliable vehicles is important to the delivery of reliable electricity to customers as outages are not unnecessarily prolonged due to vehicle breakdown when replacing the distribution equipment.
Safety	Planned replacement of fleet mitigates any catastrophic failure which may threaten the safety of employees and the public.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: Failure Risk - The main driver for this program is addressing the risk of failure of assets that are at end of typical useful life and operational effectiveness. All fleet vehicles are needed to support business needs, and over time, these units are subject to wear and tear that can impact vehicle safety, reliability, and operational efficiency. As vehicles age and mileage increases, they also incur higher operating expenses due to increasing levels of reactive repairs. In the case of the planned bucket truck replacement in 2024, V302 has been in service since 2010 and has accumulated approximately 240,000kms/3900hrs on the chassis and 4800hrs on the PTO. Based on InnPower's Fleet Policy this vehicle meets Condition IV – Needs Immediate Consideration for Replacement.

ii. Secondary Drivers: System Maintenance and Capital Investment Support – Investments into fleet vehicles, including regular maintenance, replacements when vehicles reach end of typical useful life, and additions based on staff and customer growth is essential to ensure that InnPower continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities.

iii. Information Used to Justify the Investment: An optimally timed vehicle replacement allows for overall costs to be minimized while also ensuring that the appropriate number of vehicles are available to support system maintenance and capital investment plans.

To effectively manage fleet assets, InnPower has developed a Fleet Management Policy which outlines the roles, responsibilities, and suggested criteria and scoring guideline for the replacement of vehicles. The scoring results for V302 determined at the time of purchase of is summarized below. As shown by these results, the decision to replace bucket truck V203 was primarily driven by the vehicle age and total accumulated mileage.

- **Age:** 12 points (1 point per year of service)
- **Total KM's / Hours:** 15 points (240k divided by 16k)
- **Reliability:** 3 points (Frequency of repairs)
- **Maintenance & Repair Costs:** 0 points (Note: total maintenance costs could not be provided for V302 at the time because vehicle maintenance costs were grouped together for the entire fleet. Since then, InnPower has started implementing individual tracking).
- **Condition:** 2 points (overall condition of vehicle)
- **Total Points:** 32 points (excluding M&R Costs). Condition IV-Needs Immediate Consideration for replacement.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: In order to maintain the distribution system, it is imperative that InnPower's fleet vehicles are reliable. Reliable fleet vehicles help InnPower achieve reliability targets by enabling crews to respond to outages in a timely manner. In addition, reliable fleets help InnPower efficiently construct new lines and deploy technologies that are more resilient against climate change.
ii. Cost-Benefit Analysis: Ongoing fleet vehicle maintenance is needed to ensure that InnPower staff continue to have access to safe and reliable fleet vehicles needed to support business needs. When it comes to replacing an existing end of life fleet vehicle or purchasing a new fleet vehicle to accommodate staff and customer growth, alternatives are evaluated on a case-by-case basis, quotes are obtained from manufacturers, and cost analysis is considered following InnPower's corporate purchasing policies.
iii. Historical Investments & Outcomes Observed: Historical costs are indicated in Sections A3 and A5 of this document. Historical investments in fleet have ensured that InnPower continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities. The proactive management of vehicles has also helped keep repair costs at a minimum.
iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSA – RECOVERABLE PROJECTS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower distributes electricity to residential, commercial, and industrial customers through overhead and underground infrastructure. These projects are 100% recoverable and non-discretionary which include service layouts for new residential and commercial connections, expansion of InnPower's distribution system to service new subdivisions, new distributed generation (microFIT or FIT) customer connections, recoverable capital trouble calls, 100% recoverable purchase order (RPO) projects, and fully recoverable subdivision repair works. To service many of the expansions, some existing asset upgrades are required, including, but not limited to pole replacements, overhead switch replacements/coordination, pad mounted switch replacements. All requests are reviewed against the DSC to determine InnPower's contribution level.

Projects in this program are primarily driven by customer requests as is the investment prioritization under this program. Projects constructed and connected under this program are designed in accordance with InnPower's Conditions of Service, design standards, and material specifications.

The large growth in this project is due to the significant number of developments starting to take place in the Innisfil and South Barrie area. These expansion works are required to provide power to these new sites and are driven by the developers. InnPower has also seen an increase in the number of customer driven layout requests year over year.

2. Timing

i. Start Date: The scope, timing, and schedule of the projects in this program are provided by customers.
ii. In-Service Date: 2024-2028
iii. Key factors that may affect timing: Projects may be advanced or deferred within a calendar year based on various constraints, such as:

- Budget;
- Political pressures;
- Economic development;
- Traffic flow, and
- Customer needs.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	640	537	2,558	3,721	3,825	3,373	20,559	17,823	12,055	5,067	3,841	4,117
Contributions	(605)	(598)	(2,475)	(3,732)	(3,659)	(3,151)	(20,559)	(17,823)	(12,055)	(5,067)	(3,841)	(4,117)
Capital (Net)	35	(61)	83	(11)	166	222	0	0	0	0	0	0

4. Economic Evaluation (Expansion Projects)

Economic Evaluations have, and will continue, to be completed in accordance with the Distribution System Code. InnPower works with the relevant applicants to complete these economic evaluations.

5. Comparative Historical Expenditure

Historical costs have been provided in Section A3 of this document. The level of activity/demand in this program can fluctuate from year to year based on the power requirements. Estimates for capital contribution amounts for the various projects under this program are developed from previous similar projects. InnPower is seeing a rapid increase in growth generated by developers. Some variances in historical costs between capital and contribution is due to portions of work being not fully recoverable due to InnPower driving improvements at the same time as completing customer work. Contributions in 2018 and 2020 were higher than gross capital in those same years due to up-front payment for expansion work that spanned over multiple years.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program. Mandatory projects are completed as required by InnPower, and when competing mandatory projects are undertaken InnPower ensures alignment to its project prioritization processes.

Projects in this program are primarily driven by customer requests, outage related work or the urgency of a trouble call with damaged assets. Recoverable Capital Trouble Calls require high prioritization as typically assets that have been damaged require immediate replacement to restore power to customers.

7. Alternatives Analysis

InnPower reviews the installation requirements for the design of service connections and proposes options to the customer for consideration, while offering advice on preferred options. InnPower provides costs for each option when requested (i.e., overhead design versus underground, etc.). As these projects are 100% recoverable, the final solution chosen is up to the customer (following InnPower design and standards). No costs are passed on through rates to the customers through these types of projects.
For trouble calls, assets are typically replaced on a like-for-like basis, but as per the latest construction standards / practices and material specifications.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	All new installations are designed and constructed as per InnPower's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions.
Customer Value	The renewal of infrastructure will result in an reliability in public safety and reliability as any assets that fail are replaced with new assets to the latest standard.
Reliability	Projects installed under this program are not intended for reliability improvements; however, all new construction is in accordance with InnPower current standards and specifications, which lend themselves to more reliable performance reducing the frequency of outages. Construction is coordinated and performed with minimum interruption to existing customers. Remediation of failed assets due to Trouble Calls ensures that InnPower can restore these assets to enable the maintaining of reliability levels.
Safety	Projects under this program are not intended to address safety concerns with the distribution system; however, they are designed and constructed in accordance with InnPower's established standards and specifications, in order to provide the highest level of both public and operational personnel safety. Trouble

Primary Criteria for Evaluating Investments	Investment Alignment
	Calls projects will restore assets and therefore remove any potential public safety issues.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

These projects are 100% recoverable which include service layouts for new residential and commercial connections, expansion of InnPower's distribution system to service new subdivisions, new distributed generation (microFIT or FIT) customer connections, recoverable capital trouble calls, 100% recoverable purchase order (RPO) projects, and fully recoverable subdivision repair works.

i. Main Driver: Customer service requests for connections (both new and modification to existing)
ii. Secondary Drivers: Mandated service obligations
iii. Information Used to Justify the Investment: This program, which consists of customer-initiated projects, is non-discretionary. Assets for projects under this program are issued, recovered, and disposed of as per InnPower's Asset Management Process. Forecasts costs and number of projects has been developed using historical information, as well as any current known customer requests or agreements.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower constructs all new projects using approved construction standards complying with ESA Regulation 22/04. If alternatives are requested by the customer, InnPower evaluates the cost and benefits of the proposal.
ii. Cost-Benefit Analysis: All new installations are designed and constructed as per InnPower's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions. If it is a customer request (i.e., outside a trouble call), the customer is presented with different

options, and has the final decision on the option chosen, with all costs 100% covered by the customer.

iii. Historical Investments & Outcomes Observed: InnPower collects contributed capital for 100% of the costs in this program. Capital contributions toward the cost of all customer demand projects are collected by InnPower in accordance with the DSC and the provisions of its Conditions of Service. All assets installed under this project are fully owned by InnPower. Replacement of assets due to trouble calls have resulted in improved reliability due to latest standards.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSA –SUBDIVISION PROJECTS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower distributes electricity to residential, commercial, and industrial customers through overhead and underground infrastructure. These projects, which are non-discretionary (under the Distribution System Code) consist of numerous projects which are required for expansion and connection from InnPower's distribution system to new residential subdivisions / developments. To service many of the expansions, some existing asset upgrades are required, including, but not limited to pole replacements, overhead switch replacements/coordination, pad mounted switch replacements. All requests are reviewed against the DSC to determine InnPower's contribution level.

Projects in this program are primarily driven by developer requests as is the investment prioritization under this program. Projects constructed and connected under this program are designed in accordance with InnPower's Conditions of Service, design standards, and material specifications. Where possible, capital contributions towards the cost of these projects are collected by InnPower in accordance with the DSC and the provisions of its COS. Based on estimates from subdivision developers, InnPower expects to connect approximately 1,030 units in 2024.

2. Timing

i. Start Date: The scope, timing, and schedule of the projects in this program are provided by the developers / builders and their consultants for the various projects. Through regular meetings with the developers / consultants InnPower is aware of the timetable for various projects proposed during the given budget year.

ii. In-Service Date: 2024-2028

iii. Key factors that may affect timing: InnPower considers several factors that could impact the project schedule including:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and

- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

InnPower has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	277	482	25	1,849	1,886	51	3,457	2,587	3,787	3,166	4,245	4,206
Contributions	(277)	(450)	(6)	(1,426)	(1,529)	(51)	(2,987)	(1,924)	(2,816)	(2,354)	(3,156)	(3,129)
Capital (Net)	0	33	20	423	357	0	470	663	971	812	1,088	1,077

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

Supporting the development of new subdivisions directly supports economic development. InnPower ensures that its policies and practices do not unnecessarily create barriers to economic development within its communities. Economic Evaluations have, and will continue, to be completed in accordance with the Distribution System Code and Subdivision Agreements for each new subdivision expansion project in the InnPower service territory. InnPower works with developers to complete these economic evaluations.

5. Comparative Historical Expenditure

Historical costs have been provided in Section A3. At the time of finalizing this material narrative, 2022 actuals for historical spend were not finalized, explaining the lower capital and contribution amounts for the 2022 year.

Estimates for capital contribution for the various projects listed under this program are developed from historical information of previous similar projects. The electrical distribution systems for these developer-driven projects are supplied and installed by the developer's contractor. As per InnPower's Subdivision Agreement, the developer's electrical consultant, upon completion of the installation by its contractor, is required to provide a capitalization of assets to InnPower. InnPower used an average gross connection cost of $3.5M, an average contribution of $2.6M resulting in an average net connection cost of $0.9M.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program. Mandatory projects are completed as required by InnPower, and when competing mandatory projects are undertaken InnPower ensures alignment to its project prioritization processes.

Projects in this program are driven by customer service requests, as is the investment prioritization. Assets are transferred as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreement replacement. This investment program is classed as a high priority since it is a non-discretionary program driven by customers and third-party requests, which is essential to maintain regulatory compliance and customer satisfaction. When subdivision requests are initiated under this program, they are balanced with other mandatory system access projects but will take priority over other system undertakings and plans.

7. Alternatives Analysis

Subdivisions are typically designed by developers' electrical consultants with review and input by InnPower.

The schedule of each project under this program are determined entirely by the land developers. Construction is performed by the developers' contractors.

The funding/ownership is as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreements.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	All new installations are designed and constructed as per InnPower's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions.
Customer Value	The renewal of infrastructure will result in an incremental increase in public safety and reliability.
Reliability	Projects installed under this program are not intended for reliability improvements; however, all new construction is in accordance with InnPower current standards and specifications, which lend themselves to more reliable performance reducing the frequency of outages. Construction is coordinated and performed with minimum interruption to existing customers.
Safety	Projects under this program are not intended to address safety concerns with the distribution system; however, they are designed and constructed in accordance with InnPower and USF established standards and specifications, in order to provide the highest level of both public and operational personnel safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

Projects in this program are driven by customer service requests, as is the investment prioritization under this program. Assets are transferred as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreement.

i. Main Driver: Customer service requests for connections (both new and modification to existing)

ii. Secondary Drivers: Mandated Service Obligations

iii. Information Used to Justify the Investment: Assets for projects under this program are issued, recovered, and disposed of per InnPower's Asset Management Process. This program, which consists of customer-initiated projects, is non-discretionary. Costs are recovered as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreement.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower uses established standards and construction practices, as well as preapproved standard materials for a cost-effective installation. If alternatives are requested by the customer, InnPower evaluates the cost and benefits of the proposal. InnPower informs developers that it is their responsibility to coordinate third party services to be installed. InnPower approves designs and installations as per the latest CSA, USF and/or InnPower standards which are in line with industry standards allowing third parties reasonable access.

ii. Cost-Benefit Analysis: All new installations are designed and constructed as per InnPower's latest standards, specifications, and system requirements in order to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions. InnPower collects contributed capital as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreement. All assets installed under this project are fully owned by InnPower.

iii. Historical Investments & Outcomes Observed: InnPower routinely accommodates new subdivision projects within its service territory. These investments have enabled unrestricted access to the distribution system, which in turn has allowed continued growth and development within InnPower's service areas.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSA02 – ROAD AUTHORITY WORKS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower distributes electricity to residential, commercial, and industrial customers through overhead and underground infrastructure. To accomplish this, InnPower installs significant infrastructure along road allowances that are under the jurisdictions (owned and managed) of MTO, County of Simcoe, City of Barrie, and the Town of Innisfil. , InnPower is permitted to occupy public boulevards at no cost to the utility, however, in accordance with the Public Service Works on Highways Act (PSWHA), InnPower is required to remove, relocate or reconstruct its facilities in order to accommodate the specific requirements of the road authorities during road related projects. Additionally, water and sewer main projects, either municipally or regionally driven, can also trigger relocation requests to InnPower.

Investments in road authority projects will permit InnPower to remove, relocate or reconstruct its distribution to support the road authority initiatives and the mandated requirements of InnPower's distributors licence.

The extent of the project areas varies from year to year depending on the municipality's / road authority's overall plans and on the nature of InnPower's infrastructure in the area being addressed. In the 2024 Test Year, InnPower is planning to complete the following key projects:

- Innisfil Beach Road from 10th Sideroad to Yonge Street. The County of Simcoe is expanding Innisfil Beach Road from two (2) lanes to four (4) lanes to accommodate traffic increases in the area. The County of Simcoe has requested InnPower relocate the pole line on the North Side of the road an additional three (3) meters to accommodate the widening starting in 2024. This is phase 2 of 3 for this portion of the road.

Additionally, in the 2024 Test Year, there is a scope of work planned to address street light work in the Town of Innisfil.

Cost recovery for this program is typically based upon the cost apportionment set out in the PSWHA which is identified as 100% material and 50% labour to be absorbed by the utility unless greater contributions are agreed on due to special requests by the Road Authority.

2. Timing

i. Start Date: The scope, timing and schedule of the road projects are determined by the Municipalities.

ii. In-Service Date: 2024 to 2026

iii. Key factors that may affect timing: Projects may be advanced or deferred within a calendar year based on various constraints, such as:

- Budget;
- Political pressures;
- Economic development;
- Traffic flow
- Road authority approvals; and
- Changes in project scope etc.

In addition, the schedule for these types of projects is largely dictated by various authorities and is therefore outside of InnPower's control.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	206	812	2,430	1,383	3,033	216	875	2,500	1,027	826	0	0
Contributions	(98)	(312)	(1,385)	(616)	(2,003)	(75)	(375)	(1,413)	(308)	(248)	0	0
Capital (Net)	108	500	1,046	766	1,030	141	500	1,087	719	578	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Undertaking infrastructure relocation / replacement work to accommodate road authority works projects is an ongoing activity for InnPower, and the historical actual costs associated with this program are shown in Section A3. Due to significant development in InnPower service territory, costs have been increasing year over year to accommodate the road expansions. However, due to a lack of commitment from the Road Authorities for projects in 2027 and 2028, InnPower has not included budget items for these years. As these projects are non-discretionary, if projects are to be completed, InnPower will re-assess budget constraints at that time.

Examples of completed and upcoming road authority works projects are noted in the table below:

Table 2: Completed and Upcoming Road Authority Works Projects

Year	Project Completed	Project Cost
2021	Innisfil Beach Road from 20th Sideroad to Yonge Street. This is Phase 1 of 3 of the County of Simcoe's Road widening plan.	**$0.77M***
2023	Killarney Beach Road and Yonge Street intersection. This relocation is due to the County of Simcoe widening and improving the intersection.	**TBD****

**** This is the net completed project cost (inclusive of 2020 and 2021 amounts)***
***** Construction is planned for Summer 2023.***

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program driven by third party requests and regulatory compliance. When mandatory projects are undertaken InnPower ensures alignment to its project prioritization processes.

When infrastructure relocation / replacement requests are initiated under this program, they will be balanced with other mandatory System Access projects but take priority over other system undertakings and plans. These projects are not controlled by InnPower and are a requirement of the Public Service Works on Highways Act R.S.O. 1990, CHAPTER P.49.

7. Alternatives Analysis

This investment program is classed as a high priority since it is a non-discretionary program driven by third party requests and regulatory compliance.

i. **Option 1: Do nothing –** The projects falling within the scope of this program are mandatory. These projects have a non-discretionary spend as part of delivering electricity to its customers, and as a result, doing nothing is not a viable option.

ii. **Option 2: Complying with the request to move its assets –** InnPower must comply with the request to move its assets for Road Authority projects. For each request received under this program, alternatives are considered on a case-by-case basis at the time of project implementation, and the most practical solution is pursued considering safety, regulatory, system reliability, economics, and customer relations. InnPower regularly coordinates with Road Authorities to understand project timing with as much advance notice as possible to ensure proper coordination with all involved in each project scope.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	While relocating infrastructure, InnPower considers future system service needs as well as an opportunity to upgrade or modify the infrastructure to create flexibility in operations and accommodate future needs on the system. This will reduce the need for System Service work required in the future and contribute to higher system operation efficiency and cost effectiveness in the long term.
Customer Value	The renewal of infrastructure will result in an incremental increase in public safety, reliability and infrastructure resiliency.
Reliability	While InnPower must comply with the request to move its assets for Road Authority projects, a detailed review is performed to improve reliability through updated standards, increase distribution automation and feeder redundancy.
Safety	The relocation of the distribution system needs to be done in advance of the road work. InnPower crews cannot safely work in the same time and space as the road crews. All relocation/replacement work consider safety as paramount by designing and installing to CSA standards, USF standards, InnPower standards and/or specifics approved by a Professional Engineer

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

Regional and municipal Road Authorities require InnPower to relocate the distribution system to accommodate road works projects. These projects are not controlled by InnPower and the scope is defined and determined by the limits and amount of road work / road widening being done by the Road Authority.

While InnPower must comply with the request to move its assets for Road Authority projects, a detailed review is performed to improve reliability through updated standards, increase distribution automation and feeder redundancy.

The relocation of the distribution system needs to be done in advance of the road work. InnPower crews cannot safely work in the same time and space as the road crews.

i. Main Driver: Mandated Service Obligations

ii. Secondary Drivers: Cost savings - During relocation, there may be opportunities for InnPower to update infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

iii. Information Used to Justify the Investment: InnPower's asset management process dictates that assets with the Public Service Works must be relocated to accommodate construction works in the public interest. When moving / replacing assets, consideration is given to ensure infrastructure meets current standards. InnPower regularly coordinates with Road Authorities to understand project timing with as much advance notice as possible to ensure proper coordination with all involved in each project scope.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: While relocating infrastructure, InnPower considers the opportunity to upgrade or modify the system to create flexibility in operations and accommodate future needs of the system. This will reduce the need for System Service work required in the future and contribute to higher system operation efficiency and cost effectiveness in the long term. When infrastructure relocation projects are required to accommodate municipality / road authority

projects, all areas revised are reviewed and constructed in compliance with the latest CSA, USF, and/or InnPower specific standards.

ii. Cost-Benefit Analysis: InnPower follows the Public Service Works on Highways Act R.S.O. 1990 and associated regulations governing the recovery of costs related to road reconstruction work. Project alternatives are considered on a case-by-case basis to provide the most practical and cost-effective solution for all parties.

iii. Historical Investments & Outcomes Observed: InnPower collects contributed capital for 50% of the labour, labour saving devices, and equipment rentals. Capital contributions toward the cost of all customer demand projects are collected by InnPower in accordance with the DSC and the provisions of its Conditions of Service. All assets installed under this project are fully owned by InnPower. InnPower routinely undertakes projects to accommodate municipality / road authority projects within its service territory. These investments have helped to ensure the successfully implementation of municipality / road authority projects in the past by eliminating any safety hazards relating to InnPower's infrastructure. In addition, historical work completed under this program has also enabled InnPower to update its infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSA05 – METERING

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower owns and operates 21,084 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption and demand of connected load for the purpose of billing. All existing residential and general service (GS) customers (< 50 kW) were equipped with smart meters in 2009/2010.

The Metering program includes the supply, installation, replacement and maintenance of InnPower's metering assets, in compliance with Measurement Canada standards. InnPower conducts meter re-verification through Measurement Canada, which extends the life of existing meter assets to reduce life cycle costs. The activities falling within the scope of this program includes:

(1) Installation of residential and commercial meters at new service locations; InnPower is looking to purchase 1,000 new meters on average each year over the forecast period.

(2) Upgrade of wholesale metering installations for expanded service requirements; Between 2024 and 2028, approximately 17,000 of InnPower's meters will expire and need resealing.

(3) Replacement of failed metering, expired seals, and obsolete metering for residential and commercial services; multi-residential metered customers. InnPower plans to complete the conversion of 26 existing GS >50kW customers to metering inside the settlement timeframe (MIST) meters in 2024 and 2025.

Since these investments are required by the DSC and Measurement Canada standards, they are considered non-discretionary.

Customer connection requests are fulfilled consistent with InnPower Corporation's Conditions of Service. The projects are designed to meet customer requirements and maintain system reliability and efficiency. InnPower uses standardized designs that have been engineered and approved in order to build efficiencies into the process. Through the implementation of this program, InnPower can continue to accurately and correctly measure and bill customers for the electricity that they use and satisfy the OEB "Billing Accuracy" requirement to have 98% billing accuracy.

2. Timing

i. Start Date: 2024 - The scope, timing and schedule of meter installations are initiated by external parties. Metering replacement projects are undertaken by InnPower but are largely driven by external requirements such as re-verification and equipment failure.

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: There is a schedule risk for the installation of meters at new service locations due to customer delays or restricted access to work sites. InnPower coordinates the connection of new services with customers to mitigate this risk.

Additionally, inclement weather and delays to material shipment from vendors can potentially impact timing. The final project cost also depends on the amount of labour required for each meter installation and the cost of materials.

If any meter installation is delayed due to inclement weather, InnPower will reschedule the job within a short time period to complete the work, typically within 1-2 days. As material delays are prevalent now, InnPower is increasing meter equipment inventory levels to try to mitigate any supply issues. Where longer delays are occurring, InnPower is procuring secondary meter types to bridge the shortages.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	400	264	156	687	201	216	524	500	513	525	538	552
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	400	264	156	687	201	216	524	500	513	525	538	552

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Metering services are ongoing annual expenditures. Historical costs are reflected in Section A3 above. In the previous six historical years, InnPower has purchased 3,262 meters to be used for new meter installs or meter replacements as part of this program. The following table shows the number of meters purchased each year from 2017-2022.

Meters are purchased into inventory and exact installation timing depends upon the needs of customers.

Table 2: Number of Meters Purchased Per Year

Year	# of meters purchased
2017	303
2018	1,112
2019	495
2020	109
2021	592
2022	651

The per unit cost for material and labour were derived from historical data on equivalent projects. This cost was then corrected to account for changes in exchange rates, labour, and material increases.

6. Investment Priority

This investment program is classed as a high priority / non-discretionary due to the obligation to connect new customers and the need to comply with mandated service obligations as defined by the DSC and Measurement Canada.

7. Alternatives Analysis

This is a mandatory project and a regulatory requirement. Metering asset management is governed by Measurement Canada regulations and customer requirements for new and upgraded services.

No alternatives were considered since failure to perform the work to install, repair, replace and/or reseal meters would be in violation of the DSC and Measurement Canada Guidelines, and has the potential to negatively impact the reliable source of billing settlement data.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Customer connection projects are driven by customer requests and the customer's specific technical requirements. InnPower uses standardized designs that have been engineered and approved in order to build efficiencies into the process. Customer connection requests are fulfilled consistent with InnPower's Conditions of Service. Additionally, through addressing meters that are expiring, InnPower will have reduced the number of meters that would be susceptible to unexpected failure and therefore reduce the cost for having to reactively repair these meters.
Customer Value	Benefits to the customer include timely service and supply of electricity coupled with Time of Use (TOU) pricing and data visibility. Additionally, by upgrading and renewing existing meters that are expiring, this will ensure that customer meters continue functioning, capturing accurate electricity usage, and therefore enabling InnPower to produce an accurate bill.
Reliability	InnPower Corporation uses smart meter outage flags in its Outage Management System to predict and analyze outages. This leads to a faster outage response and improved system reliability. In addition, by installing new meters that are up to current standards, this ensures that the reliability of the meters themselves continues to be maintained, thus enabling a reliable source of billing settlement data.
Safety	New meters will meet all safety standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory

obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

This program directly complies with InnPower's asset management objectives of meeting regulatory requirements and accommodating load growth.

i. Main Driver: Mandated Service Obligations – The main driver for this program is InnPower's obligation related to metering services as defined by the DSC and Measurement Canada. InnPower is obligated to install and maintain meters at all customer connection points from both residential and commercial customers. By accommodating new connection requests and by replacing meters that have expired with new meters, InnPower ensures that it complies with its obligations to provide, install, and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distribution system.

ii. Secondary Drivers: Failure Risk – By addressing expired meters, this reduces the risk of the meters failing and ensures the continued delivery of reliable and accurate bills.

iii. Information Used to Justify the Investment: New meter installations are mandatory investments arising from customer requests for new service connections, therefore customer requests are the source of information used to justify the new meter installations. InnPower also collects and tracks data on its existing meters, and this information is used to determine when a meter requires testing, resealing, or replacing.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: For new connections or service upgrades, InnPower plans and executes its metering program to accommodate customer requests and comply with regulations. All new meters installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with InnPower's standards and practices. Meter changes due to customer concerns about meter inaccuracy, and for meter seal life are driven through Measurement Canada.

ii. Cost-Benefit Analysis: This is not applicable.

iii. Historical Investments & Outcomes Observed: This historical costs and number of meters purchased during the historical period are detailed in sections A3 and A5 of this document. Through its metering program, InnPower has been able to continue to meet customer requirements, comply with relevant regulatory

requirements, and accurately and correctly measure and bill customers for the electricity that they use.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR01 – CAPITAL TROUBLE CALLS & EMERGING PROJECTS

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower is obligated to maintain safe and reliable power to its customers. While InnPower conducts regular inspection and maintenance of the distribution system and prioritizes planned replacements, there are times when a failure in the distribution system occurs and emergency replacement to restore power to customers is of paramount significance. Additionally, any assets identified that require immediate replacement due to safety concerns or imminent failures, accidents, theft, or vandalism are part of reactive capital. Investments in reactive capital projects will continue to support supply to customers and the requirements of InnPower's distributors license. While InnPower performs annual inspection and maintenance activities to aide in the proactive replacement of assets, a number of unexpected failures still take place requiring immediate actions.

This project is for small capital jobs and Capital Trouble calls that arise within the year that have not been planned for due asset failure, customer complaints or compliance issues. This project also deals with storm damage and repairs that are capital in nature including pole, transformer, conductor, switch, and switchgear replacements.

As the nature of work in this project is largely unplanned, unpredictable, and can vary significantly from year to year, InnPower has based its 2024-2028 forecast costs and projected reactive work volumes for this project on historical trends.

2. Timing

i. Start Date: These projects are reactive in nature and either address failed assets, assets at risk of imminent failure or regulatory compliance issues. Investments must be performed when identified.

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: These projects are reactive in nature and address failed assets, or assets at risk of imminent failure. Investments must be performed when identified and are prioritized over all other investments. Since the work under this program is reactionary by nature, the greatest risk is scheduling the availability of crews to perform the work. Emergency repairs may be required overnight or on weekends depending on when the trouble call is received. InnPower employs both in-house crews and external contractors to perform work as necessary to mitigate this risk.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	327	1,117	320	732	613	817	348	358	367	376	386	396
Contributions	0	0	(111)	(89)	(10)	(121)	0	0	0	0	0	0
Capital (Net)	327	1,117	209	643	603	696	348	358	367	376	386	396

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs for the 2017-2022 period are reflected in Section A3 above. Historical costs have varied year over year in accordance with specific needs identified. Due to the uncontrollable nature of trouble calls and compliance issues, this budget follows an ongoing trend based on historical information as well as previous critical items from inspections that need to be corrected. The table below shows the number of various assets replaced over the historical period.

Table 2: Historical Asset Replacements

Asset Class Description	2017	2018	2019	2020	2021	2022
Stations	0	0	0	0	0	9
Poles, Towers, Fixtures	5	8	0	14	1	14
Overhead Lines	1	64	0	4	14	123
UG Conduits	0	0	0	0	0	0
Underground Lines	0	85	0	0	30	0
Transformers	0	0	0	0	0	0
Padmount Transformers	0	0	0	0	0	0
OH Services	0	33	0	273	75	315
UG Services	20	170	0	194	0	117
Meters	0	0	0	0	0	0
Total	**26**	**360**	**0**	**485**	**120**	**578**

6. Investment Priority

These investments are classified as non-discretionary and of highest priority. These project investments have been given a priority score of 1,269.86.

These projects arise from trouble calls or inspection programs identifying an urgent need to replace system assets and the scope of the equipment replacement requires engineering. Also included in this category are projects to address customer power quality issues, and Electrical Safety Authority (ESA) due diligence inspection outcomes. Not replacing the equipment would leave customers without power which is not acceptable.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

Alternative designs are generally not considered as these projects require immediate replacement of the failed asset and are replaced like-for-like. However, InnPower does consider the replacement of other assets that are associated with the failed asset at the same time. For example, if these assets are assessed to be in poor or very poor condition, and/or are not compliant with the latest standards then they will be considered for replacement at the same time. In addition, InnPower also upgrade assets to the latest USF or InnPower standards if they do not currently meet them.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Assets are assessed to be in poor or very poor condition, and/or are not compliant with the latest standards then they will be considered for replacement at the same time.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	When failed assets are replaced with new assets, designed to latest engineering standards, InnPower will likely see an improvement in its customer reliability performance. Timely repair/replacement of assets will reduce customer inconvenience due to prolonged and frequent outages and improve our customer experience and goodwill.
Reliability	Timely replacement of damaged assets results in a reduction in outage duration which will impact the System Average Interruption Duration Index (SAIDI) metric in the near term. In the long term it will also result in a reduction in the number of outages and have a positive impact on the System Average Interruption Frequency Index (SAIFI) metric due to the installation of newer infrastructure built to the latest engineering standards.
Safety	Investments are required to address failed assets, immediate safety issues, including issues presenting a potential risk to public safety identified by the ESA, are included in this project. These actions contribute to maintaining compliance with Ontario Regulation 22/04.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower is obligated to maintain safe and reliable power to its customers. When a failure in the distribution system occurs, emergency replacement to restore power to customers is paramount. Additionally, any assets identified that require immediate replacement due to safety concerns or imminent failures, accidents, theft, or vandalism are part of reactive capital. Investments in reactive capital projects will continue to support supply to customers and the requirements of InnPower's distributors license and allow InnPower to continue to deliver a safe and reliable service to its customers.

i. Main Driver: Asset failure since assets are operating at the end of their service life

ii. Secondary Drivers: System operational objectives: safety risk, compliance, and reliability

iii. Information Used to Justify the Investment: Not replacing equipment that has failed and leaving customers without power is in direct contravention to the Distribution System Code Section 4.4. Due to the nature of the work being unpredictable and emergent and therefore reactive, InnPower has used historical asset failure information to help forecast the potential number of asset failure it may experience each year.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: When replacing failed assets, consideration is given to ensure that the new infrastructure meets current standards.

ii. Cost-Benefit Analysis: Emergent replacement work is required to be carried out immediately, due to the nature of the failure. When considering the appropriate solution InnPower typically consider the following options. Each failure is assessed on a case-by-case basis to determine the most appropriate solution considering, cost, customers impacted, length of outage, and availability of spare assets that are required.

- **Like for Like replacement:** this solution is undertaken when the current failed asset meets the latest standards.
- **Upgrade to latest USF standards:** this solution is enacted when the failed asset does not meet the latest standards and is therefore replaced with an asset that meets the latest standards.
- **Replacement:** In addition, InnPower consider if any assets associated with the failed asset require replacing.

iii. Historical Investments & Outcomes Observed: Through its historical emergent replacements, InnPower has continued to be able to minimize outage frequency and durations for its customers when a failure has occurred. In addition, InnPower has been able to remove any safety risk to the public or its employees resulting from the failed assets.

The program budget is based on previous years' expenditures and the expected amount of work over the forecast period. Actual expenditures may vary based on the number, timing, and nature of the trouble calls received. InnPower has mitigated this risk through careful planning and reduces costs by using standardized designs and a like-for-like replacement strategy whenever feasible.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR02 – TRANSFORMERREPLACEMENT

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Transformers allow InnPower to change the voltage from a distribution level to a customer utilization level. InnPower inspects distribution transformer installations according to the inspection requirements established by the OEB Distribution System Code and ESA Regulation 22/04. The proposed replacement candidates are selected based on:

- the condition as identified by the asset condition assessment (ACA) and annual inspections,
- identified safety issues,
- environmental concerns, and/or
- consistent and significant overloading of the transformer.

A few examples of deteriorated transformers requiring replacement are shown in the following figures.



Figure 1: Example of corrosion rusting out the locking mechanism of a padmount transformer



Figure 2: Example of a leaking padmount transformer needing immediate replacement and environmental clean up

This project includes the proactive replacement of all types of distribution transformers within the InnPower service territory including polemount single and three-phase transformers and padmount single and three-phase transformers. InnPower is targeting fifteen (15) transformers to be replaced annually, but this figure is heavily dependent on the number of overhead units versus underground units that need to be replaced in a given year, in addition to any environmental remediations that need to be carried out during the replacement. Investments in transformer replacements will enable InnPower to mitigate safety, environmental, and reliability risks associated with the failure of these assets.

2. Timing

i. Start Date: This is an annual investment initiative to manage end-of-life assets and will take place over the time period of 2024 to 2028.

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: InnPower considers the following as general risks to project schedule:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

InnPower has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	109	10	105	74	336	108	150	157	161	165	169	173
Contributions	0	0	0	0	(46)	(12)	0	0	0	0	0	0
Capital (Net)	109	10	105	74	290	95	150	157	161	165	169	173

The overall program costs detailed above are inclusive of inflation, material, and labour charges. Please note that supply chain costs were volatile in 2021 and 2022 due to shortages in transformers and therefore costs increased.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are presented in Section A3 above. This project is the continuation of InnPower's long-term annual transformer replacement initiative. The year-over-year variation for the historical period is primarily due to supply chain issues. This was prevalent across the industry with shortages of transformers available and above normal inflation. The table below presents the number of transformers replaced over the historical period by transformer type.

Table 2: Historical Transformer Replacements

Year	Padmount	Polemount	# of Transformers Replaced
2017	2	7	9
2018	1	3	4
2019	9	1	10
2020	9	13	22
2021	2	14	16
2022	5	5	10

The average annual investment proposed is to replace units based on inspection results from both the ACA and InnPower's annual inspection program. Note that the forecast costs also account for increased inflation and increased material and labour costs.

6. Investment Priority

This is considered a medium investment priority and has a priority score of 457.62. In order to maintain system integrity and reliable service to the customers, InnPower plans to replace its overhead and underground transformers (e.g., pole-top and padmounted transformers) with the new standardized transformers based on prioritization from inspection and ACA results. If not replaced, the identified transformers that are in poor and very poor condition will deteriorate further and will fail more often to the level that is not manageable by InnPower and not tolerable by the customers.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", the Typical Useful Life of distribution polemounted and padmounted transformers is 40 years. Several units of InnPower's existing distribution transformer population are approaching this 40 years benchmark and are expected to fail more if not replaced. While age is a factor, InnPower utilizes the results of the ACA to ensure a detailed review and a condition-based decision is completed prior to selecting candidates for replacement.

Each year InnPower conducts field inspections of its transformer population and uses the inspection results to update the ACA and to prioritize and select suitable candidates for replacement. Some of the options that are considered when evaluating a transformer replacement include:

i. **Do nothing and run to fail:** As long as there are no safety (corrosion or oil leaks) issues present, this is the typical InnPower approach for transformer replacement. While this can be employed for unplanned and unexpected failure of transformers, it is not sustainable to carry out for all transformer replacements. Customers would experience longer and increased unexpected outages. In addition, replacing transformers reactively generally incurs a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase. This ultimately would increase reactive renewal costs.

ii. **Like for like replacement (proactive):** This is the preferred approach when inspection and ACA data dictates that a transformer be replaced. Through this approach InnPower is able to address the high priority at risk assets, mitigating safety, environmental concerns, and ensuring reliability levels are maintained. The proposed proactive replacement of unsafe transformers will ensure that the number of unplanned outages remain minimal by avoiding asset failures, so that the customers have access to reliable electricity for their needs. Costs also be reduced when compared with a completing all transformers under a reactive program.

iii. **Upgrade to address overloading issues:** this is usually brought up through customer complaints and is very sporadic year over year.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current InnPower specifications and design standards and will improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work and prolonged outage restoration time.
Customer Value	The proactive replacement strategy of the project as planned is less costly than reactive replacements. Proactive replacements help to minimize potential public safety risks and outage impacts to customers.
Reliability	This project is part of the long-term replacement program and are expected to maintain or improve reliability by minimizing the risk of transformer failure.
Safety	Transformer failures pose safety risk to staff and the public. The transformer may fail when staff are working on the unit or when the public is in close proximity to the unit. Additionally, during recent inspections it was observed that many units had excessive rusting, and, in some cases, it had caused holes to develop in the units. Such units pose a greater safety risk to public as it gives them potential access to high-voltage conductors. Another trend found during recent inspections was oil leaks, so it is imperative that these issues are resolved as soon as possible to reduce the impact to the environment. Investments in proactive transformer replacements under this program will help mitigate the safety and environmental risks associated with failure of these assets.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory

obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower is experiencing an increasing rate of decline in reliability on its distribution system. Defective equipment is the leading cause of controllable outages in the distribution system.

i. Main Drivers:

   a. Failure Risk – One of the main drivers for the proactive transformer replacement is to minimize failure risk associated with very poor or poor conditioned transformers as identified in the ACA. Proactively identifying and replacing transformers minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages. This aligns with the customers' requirement of the utility maintaining a similar level of reliability and minimizing outages.

   b. Safety concerns – Public safety and risks to the environment is another main driver for this program. Proactively replacing identified transformers mitigates the risk of the assets failing in service and prevents resulting environmental hazards.

ii. Secondary Driver: Outage optimization and efficiency– Proactive replacement of an asset on a planned basis, is more cost effective than an unplanned, reactive replacement, as well as optimizes the outage time and size to InnPower's customers.

iii. Information Used to Justify the Investment*:* Each year, InnPower carries out the annual inspection program to approximately 1/3 of the transformer population with data used to populate the ACA. Then on a prioritized basis, InnPower will re-visit, review, and select the worst transformer units for replacement. The locations and priority are determined based on the results from the inspection process, along with discussion and feedback among Lines, System Control, and Engineering teams. Additional reference information on the prioritization factors used for poles and the condition results is included in the DSP (Section 5.3.2.2.2) and in Appendix J – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: Transformer replacements are critical to maintain the reliability of the overall grid. Transformers are sized appropriately to ensure potential future needs. Various aspects are considered to identify

appropriate transformer size, including potential development opportunities and planning for increased load requirements such as electric vehicle charging stations.

Proactively replacing poor and very poor transformers at or nearing end of life prior to failure will reduce the cost per transformer as the work can be performed during regular business hours avoiding overtime premiums. InnPower constructs all new projects using approved construction standards complying with ESA Regulation 22/04.

ii. Cost-Benefit Analysis: InnPower replaces the minimum level of transformers based on safety concerns (corrosion or oil leaks) or imminent failure (Infrared Scan) to ensure the cost stays as low as possible while maintaining reliability. Doing nothing and running distribution transformers to failure is more costly and more impactful relative to proactive replacement as it could impact public safety, could pose a threat to the environment due to an insulating oil leak or spill, or could decrease reliability to the connected customer(s).

Taking a proactive approach will eliminate the risk of a power outage and working after hours to replace a failed transformer, and as a result the cost per transformer will be decreased and controlled as the work can be performed during regular business hours avoiding overtime premiums. The proactive approach will also reduce outage time to customers and help provide customers with better reliability.

iii. Historical Investments & Outcomes Observed: Historical costs have been presented in Section A3 of this document. The proactive replacement strategy of the project as planned is less costly than reactive replacements while mitigating safety, environmental concerns, and outage impacts to the customers.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

Due to significant supply chain issues, especially with regards to the purchase of transformers, InnPower has joined an initiative being led by the USF to align the standards and specifications around transformers with other utilities facing similar supply chain constraints. This buying group recently sent out an RFP to numerous vendors and are currently in the process of evaluating the submissions.

The objective is to find economies of scale in terms of the type of transformers; features of transformers; use a higher number of purchases to gain space in the production line; and determine cost savings in both production and transportation/delivery.

Through this process, InnPower is now able to place an order for transformers in 2023 where if InnPower had not participated in this buying group, InnPower would not have the ability to place an order for single phase units.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR03 – POLEREPLACEMENT

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower relies on poles to support distribution system attachments and maintain safety for the public, as poles provide physical separation between ground level and energized conductors. InnPower must maintain these assets in a safe and serviceable condition in order to maintain a safe and reliable supply to its customers.

As identified through the asset condition assessment, the poles that are in poor or very poor condition need to be replaced before they fail. The poles that are in poor or very poor condition are prioritized based on the number of circuits those poles serve, i.e., a two-circuit pole takes priority over a single-circuit pole; likewise, a pole with a 3-phase supply on it would take priority over a pole with a single-phase supply.

Investments in pole replacements will mitigate safety and reliability risks associated with the failure of these assets and maintain regulatory compliance with respect to minimum strength values.

InnPower must assess and monitor the condition of its pole population to ensure that its poles remain in a safe and serviceable condition while meeting prescribed codes for safety and reliability. InnPower does this through annual pole inspection and testing programs. InnPower performs pole residual strength testing on wood poles to assess remaining strength along with the field inspection for wood poles. This is a key indicator of the condition of the pole.

InnPower complies with industry standards from Canadian Standards Association (CSA) in its overhead construction, namely CSA Standard C22.3 No. 1-10 [3]. Clause 8.3.1.3 of the Standard states: "When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced". InnPower is governed by the Electrical Safety Authority (ESA) standards, guidance, and reporting requirements as part of its compliance. Without the planned pole sustainment investments, InnPower would not be able to adhere to the adopted CSA standards and risk compliance with ESA and other regulatory entities.

This program covers proactive wood pole replacements. As part of this proactive program, InnPower plans to replace 40 poles per year on average over the next five (5) years. Any reactive work associated with wood poles is addressed through the Capital Trouble Call program (IPCSR01).



Figure 1: **Example of leaning pole that was found during visual inspection in 2021 and replaced/corrected in 2022.**

2. TIMING

i. Start Date: This is an annual investment initiative to manage end-of-life assets.

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: InnPower considers several factors that could impact the project schedule, including:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and,
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

InnPower has utilized coordination with third parties (municipalities/suppliers/customers) to mitigate some of the issues where possible.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	1,660	356	383	752	546	1130	360	363	500	513	525	538
Contributions	0	0	0	(67)	(110)	(6)	0	0	0	0	0	0
Capital (Net)	1,660	356	383	686	437	1124	360	363	500	513	525	538

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

The significant expenditures in 2017 is primarily attributed to the work performed for the Friday Harbour expansion project. The costs for this project were later recovered through the economic evaluation process.

In collaboration with the Lake Simcoe Region Conservation Authority (LSRCA), InnPower has installed Osprey Nesting poles. These new nesting platforms would provide the Osprey with a safe space to nest while protecting InnPower's power system. With respect to the installation of streetlight, the Town of Innisfil required pole upgrades that benefitted both utility and town. These reasons resulted in capital contributions in years 2021 and 2022.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are presented in Section A3 above. This project is the continuation of InnPower's long-term annual pole replacement initiative. The average annual investment proposed is to replace units based on inspection results. The table below shows the number of poles replaced over period the historical.

Table 2: Historical Pole Replacement and Costs

Year	# of Poles Replaced
2017	161
2018	57
2019	46
2020	59
2021	44
2022	59

The average annual investment proposed is to replace units based on inspection results from both the ACA and InnPower's annual inspection program. Note that the forecast costs also account for increased inflation and increased material and labour costs.

6. Investment Priority

This is considered a medium investment priority overall and has a priority score of 335.64. Within the System Renewal investment category, this project is assigned the highest priority. Proactively identifying and replacing poles minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages and safety risks.

The planned pole investments are needed to address the volume of deteriorated poles on InnPower's distribution system, and comply with external codes/standards. Proactively identifying and replacing poles that are decrepit (poor and very poor condition) and close to failure minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages. This aligns with the customer's need for the utility to maintain a similar level of reliability and minimize outages. More information on the prioritization factors considered in the condition assessment can be found in Appendix J – Asset Condition Assessment Report of the DSP.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of wood poles is 45 years. Many units of InnPower's existing wood pole population are approaching that 45 years benchmark and are expected to fail more if not replaced. While age is a factor, InnPower utilizes the results of the ACA to ensure a detailed condition-based review is completed prior to selecting candidates for replacement. This considers factors beyond age.

Each year InnPower conducts field inspections of poles and uses the inspection results to update the ACA and to prioritize and select suitable candidates for replacement. Some of the options that are considered when evaluating a pole replacement:

i. **Do nothing and run to fail:** InnPower does consider reactive replacement for some pole replacements. While this can be employed for unplanned and unexpected failure of poles, it is not sustainable to carry out for all pole replacements. Customers would experience longer and increased unexpected outages. In addition, replacing poles reactively generally incurs a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase. This ultimately would increase reactive renewal costs. Typically, these poles are addressed in the Cap Trouble Call program.
ii. **Like for like replacement (proactive):** This is the standard approach when inspection and ACA data indicates that a pole needs replacing. All poles are replaced with the latest standard design. The proposed proactive replacement of unsafe poles will ensure that the number of unplanned outages remains minimal

by avoiding asset failures, so that the customers have access to reliable electricity for their needs. Costs will also be reduced when compared with completing all poles under a reactive program.

iii. **Upgrades:** If a pole has been identified as needing upgrading this is typically done with coordination with third parties, customers, road authority, and expansion developments. If these are driven by a third-party then these are carried out under System Access projects.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current InnPower specifications and CSA and USF design standards and will improve reliability. The proactive replacement of an asset is more cost-effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. InnPower utilizes a one-visit approach when considering pole replacement projects to minimize the return visits to upgrade or replace pole attachments at a later date. (i.e., whilst replacing a pole, InnPower will see if assets attached to it or in the vicinity also require replacement)
Customer Value	The investment will eliminate the concerns of low line clearances and imminent pole failures that could pose a safety and reliability risk. The proactive replacement strategy of the project is less costly than reactive replacements.
Reliability	This project is part of the long-term pole remediation program and will enable InnPower to maintain reliability.
Safety	Pole failures pose safety risk to staff and the public. The pole may fail when staff are working on the pole or when the public is in the proximity of the unit. When the pole falls, there may be other equipment (e.g., overhead transformer or overhead switch) that could also fall. This project will directly address and help eliminate these safety issues by replacing poor and very poor condition poles.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

The planned pole investments are needed to address the volume of deteriorated poles on InnPower's distribution system, and comply with external codes/standards.

i. Main Driver: Failure Risk – the main driver is to minimize the failure risk associated with very poor or poor conditioned poles as identified in the ACA.

ii. Secondary Drivers: System operational objectives including safety and reliability. Through the proactive replacement of poor and very poor conditioned poles, InnPower can minimize safety issues, as well as maintain reliability levels.

iii. Information Used to Justify the Investment: Pole failures pose a safety risk to staff and the public. In the case that there are transformers on the pole, a pole falling down may also cause the transformers to fall down and fail. Hence, InnPower utilises its GIS system to overlay the poles identified as decrepit (poor and very poor) with its system map to identify the locations and how many customers could be impacted (as well as critical infrastructure connected e.g., a hospital) by an unexpected failure, resulting in a transformer tank rupturing, and oil being spilled onto the ground. Additional reference information on the prioritization factors used for poles and the condition results is included in the DSP (Section 5.3.2.2.2) and in Appendix J – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower complies with industry standards from Canadian Standards Association (CSA) in its overhead construction, namely CSA Standard C22.3 No. 1-10 [3]. Clause 8.3.1.3 of the Standard states: "When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced". When replacing the decrepit poles, InnPower will consider certain components of the pole framing for reuse after a thorough inspection. Given that the pole and all equipment on it are generally the same age, refurbishment is not likely an option. However, certain items such as down guys and stand-off brackets may be considered for reuse or a second lifecycle to minimize costs where possible.

In addition, it is prudent and a good utility practice to assess any assets that are associated with the pole to determine if they require replacement at the same time or if they can be transferred to the new pole. InnPower utilizes a one visit approach when considering pole replacement projects to minimize the return visits to upgrade or replace pole attachments at a later date.

Additionally, InnPower continues to employ a Vegetation Management strategy on a four-year cycle across all its service areas. This helps InnPower minimize outages and momentary disruptions due to tree contacts.

ii. Cost-Benefit Analysis: Running thepoles to failure is an option that is considered, and some poles are addressed reactively by InnPower. However, this is not a feasible option to consider for all poles, as this would result in a backlog of poles that require replacement or treatment above InnPower's execution capabilities. In addition, this would significantly reduce the reliability of the system and cause more outages to customers. Although continuing to run poles to failure may reduce the level of targeted capital investment in replacement, the risks associated with this alternative are not worth the cost savings due to increased safety, reliability, and system performance risks.

InnPower is proposing to proactively replace the identified poor and very poor condition poles on a like for like basis and upgrade them to the latest standards where they don't currently meet it. As distribution poles are considered an integral and critical component of the distribution system there is no alternative to like for like replacement beyond the height or wood makeup of the replaced pole. The benefits of like for like replacement is the ability accurately forecast pole health and degradation and apply consistent inspection techniques to health assessments, providing efficiency and cost savings in O&M going forward.

iii. Historical Investments & Outcomes Observed: Historical costs are presented in Section A3 of this document. The proactive replacement strategy of the project as planned is less costly than reactive replacements. InnPower's strategy has been to sustain the system and continue to maintain reliability and continue to minimize outages, and this is what has been seen during the 2018-2022 period. Reliability levels have typically been maintained. Safety from falling poles has continued to be addressed with no increase in any safety issues.

iv. Substantially Exceeding Materiality Threshold: Like all other utilities, replacing and maintaining the condition of its poles is a continuing yearly program. Every year, InnPower assesses the number of poles that need replacement and balances this off against other priorities.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR04 – RECLOSERREPLACEMENT

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Reclosers are a distributor's main method of switching loads for system operation and to restore customers after an outage. Reclosers, like switches are a tool by which InnPower can sectionalize and isolate parts of the distribution system when needed.

Defective equipment is the leading cause of controllable outages in the distribution system. InnPower plans to replace all of the poor and very poor condition oil line reclosers in the distribution system with automated reclosers. In addition, reclosers that are identified in good or better condition but are functionally obsolete, no longer operable or incapable of interrupting load current and are an environmental and safety risk will also be replaced. Investments in recloser replacements will mitigate safety and reliability risks associated with failure of these assets.

Replacing deteriorated reclosers not fit for operation allows InnPower to quickly restore service, transfer supply and enable isolation from the System Control. This will support automatic system restoration thereby reducing the need for crews to operate reclosers and permitting crews to focus on fault identification and repair.

Customers will experience improved reliability as a result of the sustainment of deteriorated and functionally obsolete assets. InnPower will avoid the safety and environmental concerns associated with oil filled recloser failure through the installation of remotely controlled switches. InnPower plans to replace three (3) reclosers per year based on the removal of oil-filled reclosers, inspection results and the Asset Condition Assessment (ACA). This renewal investment is supported by customers.

2. Timing

i. Start Date: This is an annual investment initiative to manage end-of-life assets starting Jan 2024.

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: InnPower considers the following as general risks to project schedule:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;

- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

InnPower has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	44	0	28	153	182	200	205	210	216	221
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	44	0	28	153	182	200	205	210	216	221

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The historical expenditures are presented in Section A3 above. This project is the continuation of InnPower's long-term annual recloser replacement initiative. The average annual investments proposed is to replace units based on inspection results. In the past, InnPower was replacing oil reclosers on an as needed ad hoc basis, which is why there was no spend on this program in 2017-2018 and 2020. However, in 2022 InnPower determined it was prudent to proactively replace these units over the next cost of service period to reduce environmental and safety risks as well as reliability concerns.

Table 2: Historical Recloser Replacement and Costs

Year	# of Reclosers Replaced
2017	0
2018	0
2019	2*
2020	0
2021	1*
2022	3

**** These replacements were like for like replacements, which means that oil-filled reclosers were replaced with refurbished oil-filled recloser. Due to the significant cost increase in 2021, InnPower transitioned the program to install solid dielectric units moving forward with automation capabilities.***

The plan is to replace 3 units per year moving forward until all oil filled units have been decommissioned. It must be noted that the budget allocated towards this program only encompasses the replacement of distribution line reclosers. InnPower plans to replace three (3) units per year over the forecast period. The forecast costs also account for increased inflation and increased material and labour costs.

6. Investment Priority

This is considered a medium investment priority on the whole and has a priority score of 473.30. However, in comparison to other System Renewal programs, this program ranks high. Proactively identifying and replacing reclosers minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages thereby allowing InnPower to quickly restore service, transfer supply and enable isolation from the System Control. This aligns with customers desire of the utility maintaining a similar level of reliability and minimizing outages.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of station reclosers is 45 years. Many units of InnPower's existing station recloser population are less than 20 years and are in very good or good condition. While age is a factor, InnPower utilizes the results of the ACA to ensure a detailed review is completed prior to selecting candidates for replacement.

Each year InnPower conducts field inspection of reclosers and use the inspection results to update the ACA and to prioritize and select suitable candidates for replacement. The selected reclosers will be replaced by automated reclosers. Some of the options that are considered when evaluating a recloser replacement:

i. **Do nothing and run to fail:** Some recloser units have been run to failure but this presents a significant reduction in reliability and worker safety. While this is not the preferred method, in some cases, due to budgetary or supply chain constraints, this option is used.
ii. **Like for like replacement (proactive):** InnPower no longer purchases oil filled reclosers due to the limited functionality, associated environmental concerns, and frequent maintenance requiring taking these switches out of service for testing / oil replacement and re-installation every three (3) years.
iii. **Upgrade to latest standard:** This is the preferred method to align with InnPower approved material, increased functionality leading to increase reliability and faster remotely capable restoration times.

8. Innovative Nature of the Project

This project will add automation onto the InnPower distribution system thereby improving reliability, reducing truck rolls, and reducing safety risk. Reclosers controlled and monitored remotely are able to sectionalize and reduce outage sizes significantly and all before a call is dispatched to field staff. This limits the scope of an outage as well as provides detailed information to field staff on the possible location of the outage.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current InnPower specifications and design standards and will improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. Additionally, the new reclosers will be automated allowing for a reduction in truck rolls.
Customer Value	The proactive replacement strategy of the project as planned is less costly than reactive replacements. Customers will experience improved reliability as a result of the sustainment of deteriorated and functionally obsolete assets.
Reliability	This project is part of the long-term replacement program. Reliability will be adversely affected when a recloser fails to operate when required as part of switching to restore service. Automated reclosers provide rapid transfer of loads in emergencies, reduce

Primary Criteria for Evaluating Investments	Investment Alignment
	restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak, provide real time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system.
Safety	Automated reclosers provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak, provide real time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

Defective equipment is the leading cause of controllable outages in the distribution system.

i. Main Driver: Failure Risk – The main driver is to replace assets at end of functional service life due to failure risk as informed by the ACA.

ii. Secondary Drivers: System operational objectives including safety, reliability, functional obsolescence, environmental impacts of oil-filled reclosers.

iii. Information Used to Justify the Investment: Reclosers are a distributor's additional method of switching loads for system operation and to restore customers after an outage. Reclosers, like switches, are the basic tool by which InnPower can sectionalize and isolate parts of the distribution system when needed. Additional reference information on the prioritization factors used for reclosers and the condition results is included in the DSP (Section 5.3.2.2.2) and in Appendix J – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the

justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: Proactive replacements prior to failure will reduce the cost per recloser as the work can be performed during regular business hours avoiding overtime premiums. InnPower addresses functional obsolescence by constructing all new projects using approved construction standards complying with ESA Regulation 22/04.

ii. Cost-Benefit Analysis: InnPower believes that keeping pace with projected failure rates strikes a balance between risk and cost. While the cost of the proposed spend is greater than historical spend, it is consistent with customers' preference for improving reliability. The cost to refurbish oil filled units continues to increase in price without providing the reliability or function capability in InnPower's current approved recloser. The added benefit of only visiting a pole once to replace the unit with a new unit (with a longer lifespan) and added functionality will reduce the annual maintenance cost once all oil filled units are removed from the system.

iii. Historical Investments & Outcomes Observed: Historical costs are outlined in Section A3 of this document. The proactive replacement strategy of the project as planned is less costly than reactive replacements and have helped improve reliability & minimize outage impacts to customers, reduce safety risks, improved operational efficiency.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR05 – SWITCH REPLACEMENT

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower is experiencing an increasing rate of decline in reliability on its distribution system. Defective equipment is the leading cause of controllable outages in the distribution system. InnPower plans to replace all of the very poor condition switches as identified in the ACA in the distribution system as well as replacing switches that are functionally obsolete, no longer operable or incapable of interrupting load current. Investments in switch replacements and other renewal investments will mitigate safety and reliability risks associated with failure of these assets.

Proactively identifying and replacing switches minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages. This aligns with customers wants of the utility maintaining a similar level of reliability and minimizing outages. Additionally, proactive replacements are not as cost intensive as reactive replacements.

The program starting in 2024 and beyond will address units that have come back in the previous inspections with damaged components, safety issues, communication deficiencies and non-load break capabilities. InnPower aims to replace two (2) gang operated switches per year and any in-line switches which may be compromised as indicated by InnPower's ongoing infrared inspections report.

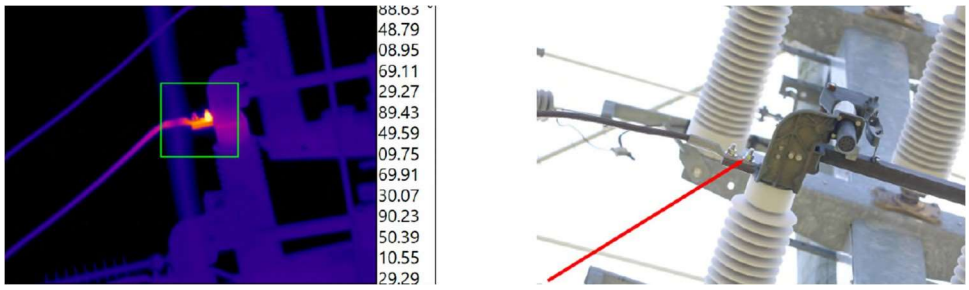


Figure 1: Example of a hot spot identified from InnPower's 2021 Inspection which required the switch to be replaced



Figure 2: Switch control cabinet showing severe rusting from 2021 visual inspection.

2. TIMING

i. Start Date: 2023

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: InnPower considers several factors that could impact the project schedule including:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and
- general unforeseen delays such as striking rock when digging, tree conservation, municipal / regional consent forms.

InnPower has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities / region / suppliers / customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital	0	52	0	80	117	4	151	166	170	175	179	183
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	52	0	80	117	4	151	166	170	175	179	183

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical expenditures are outlined in Section A3 above. InnPower replaced one (1) gang operated switch in 2018, one (1) gang operated switch in 2020 and one (1) gang operated switch and multiple in-line switches in 2021 based on results from field inspections and the ACA. These units were replaced on a like for like basis with the only changes being new models and features from the manufacturer. The drop in 2022 is explained by the replacement of an in-line manual switch that was identified as an imminent failure risk through InnPower's annual infrared and visual inspection results.

The program starting in 2023 and onwards is to address units that have been identified in previous inspections with damaged components, safety issues, communication deficiencies and non-load break capabilities. The target is to replace two (2) gang operated switches per year and any in-line switches which are compromised from InnPower's infrared inspection program.

6. Investment Priority

This is considered a medium investment priority and has a priority score of 181.90. However, in comparison to other System Renewal programs, this program ranks low. Overhead switches are a distributor's main method of switching loads for system operation and to restore customers after an outage. Switches are the basic tool by which InnPower can sectionalize and isolate parts of the distribution system when needed.

Replacing deteriorated switches and switches that are not fit for operation, either because they are functionally obsolete, no longer operable, or otherwise incapable of interrupting the load allow InnPower to quickly restore service, transfer supply and enable isolation from the System Control. This will reduce the need for crews to operate switches and permit crews to focus on fault identification and repair.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of station switches is 50 years and the Typical Useful Life of distribution switches is 45 years. All of InnPower's station switches are less than 20 years and are in very good condition and the majority of its distribution switches are less than 30 years and are in either very good or good condition. While age is a factor, InnPower utilizes the results of the ACA to ensure a detailed review is completed prior to selecting candidates for replacement.

Each year InnPower conducts field inspection of switches and use the inspection results to update the ACA and to prioritize and select suitable candidates for replacement. Some of the options that are considered when evaluating a switch replacement:

i. **Do nothing and run to fail:** Some switch units have been run to failure, but this presents a significant reduction in reliability and worker safety. While this is not the preferred method, in some cases, due to budgetary or supply chain constraints, this option is used.
ii. **Like for like replacement (proactive):** This is the preferred method to align with InnPower standards and increases functionality leading to an increase in reliability and faster remotely capable restoration times.
iii. **Upgrade to latest standard:** While an upgraded model of the switch is used, this falls under the like for like category as the device and device capabilities are similar in nature. InnPower presently does not upgrade gang-operated switches from the current installations.

8. Innovative Nature of the Project

This project will add automation onto the InnPower distribution system, improving reliability, reducing truck rolls, and reducing safety risk. Automated switches are able to identify fault current levels, fault direction and have the ability to be operated remotely without having the need for a truck roll. This can either assist with sectionalizing an outage to a small area or transfer loads between stations which will further improve system reliability and address customers' reliability concerns.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current InnPower specifications and design standards and will improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. This program thereby positively impacts dispatching efficiencies.
Customer Value	The proactive replacement strategy of the project as planned is less costly than reactive replacements. Customers will experience improved reliability as a result of the sustainment of deteriorated and functionally obsolete assets. InnPower will avoid the safety risks of manually operated switch failure through the installation of remotely controlled switches. The safety risks associated with legacy air-brake switches, which cannot be operated under load (i.e., non-load-break switches) will also be eliminated as these switches are removed from the system. This renewal investment is supported by customers.
Reliability	This project is part of the long-term replacement program. Reliability will be adversely affected when a switch fails to operate when required to restore service. Automated switches provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak, provide real time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system.
Safety	Automated switches provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak, provide real time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system. Proactively

Primary Criteria for Evaluating Investments	Investment Alignment
	replacing identifying switches mitigates the risk of the assets failing in service and controls the hazards to a reasonable level.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower is experiencing an increasing rate of decline in reliability on its distribution system. Defective equipment is the leading cause of controllable outages in the distribution system.

i. Main Driver: Assets at end of service life due to failure risk – ACA defined levels of failure risk and the results of ACA for station and distribution switches assessed would be a primary risk driver.

ii. Secondary Drivers: System operational objectives including safety, reliability and increase functionality.

iii. Information Used to Justify the Investment: Switches are a distributor's main method of switching loads for system operation and to restore customers after an outage. Switches are the basic tool by which InnPower can sectionalize and isolate parts of the distribution system when needed. Additional reference information on the prioritization factors used for switches and the condition results is included in the DSP (Section 5.3.2.2.2) and in Appendix J – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower addresses functional obsolescence by constructing all new projects using approved construction standards complying with ESA Regulation 22/04.

ii. Cost-Benefit Analysis: Keeping pace with projected failure rates strikes a balance between risk and cost. While the cost of the proposed spend is greater than historical spend, it is consistent with customers' preference for improving reliability and reducing worker safety risk. Hence, the proactive method of replacing like-for-like switches is preferred.

iii. Historical Investments & Outcomes Observed: Historical costs are outlined in Section A3 of this document. The proactive replacement strategy of the project as planned is less costly than reactive replacements. Historical expenditures have enabled IPC to ensure continued delivery of safe and reliable service.

Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR06 – SWITCHGEARREPLACEMENT

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Underground distribution systems are based on large "trunk" feeder cables that are connected to smaller power cables that serve customers. Due to their size, the larger feeder cables cannot be directly connected to the transformers used in the distribution system. The system relies on pad-mounted switchgear to connect local distribution circuits to the main feeder cable systems, and to interconnect multiple trunk feeder circuits. A single switchgear can impact as a many as 1,000 customers in larger subdivisions. InnPower plans to replace all of the very poor air-insulated switchgear.

The reported useful life of pad-mounted switchgear is 20-45 years with a typical useful life of 30 years; however, due to increasing environmental factors, these units have failed at service ages as low as 11 years. InnPower is experiencing an increasing rate of decline in reliability on its distribution system due to defective equipment. InnPower has identified a need to increase the investment in replacing 25kV air-insulated dead front switchgear due to internal contamination and damage to the enclosure of some units based on inspection results.

InnPower plans to replace all the air-insulated switchgear units in the system that are in very poor condition based upon inspection and ACA results with solid dielectric switchgear units. Investments in switchgear replacements will mitigate safety and reliability risks associated with failure of these assets. InnPower plans to replace one (1) switchgear per year based on the identification of the switches that are in very poor condition through the inspection data and ACA results.



Figure 1: Switchgear found during 2021 Inspection with a dented door making the unit unable to open



Figure 2: Switchgear found during 2021 inspection with rust. Unit is being monitored for any safety impacts

2. Timing

i. Start Date: 2024

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: InnPower considers several factors that could impact the project schedule including:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

InnPower has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	33	0	60	57	22	106	108	111	114	116
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	33	0	60	57	22	106	108	111	114	116

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are shown in Section A3 above. InnPower replaced one (1) switchgear in 2021 and 2022 in a like for like replaced based on results from field inspections and the ACA. These units were replaced with switchgears from inventory; therefore, it was an air-insulated for air-insulated replacement. The program starting in 2024 and onwards is to address units that have come back in the previous inspections with damaged enclosures, which prevents InnPower from accessing or operating them. The increased cost in the program is due to InnPower's transition from air-insulated, which is susceptible to

contamination, with a Solid Di-electric model which is a fully contained unit, as fluctuating supply chain costs. The target is to replace one (1) unit per year.

6. Investment Priority

This is considered a medium investment priority both on the overall program portfolio level and also in comparison to other System Renewal programs. This program investment has a priority score of 373.23.

The reported useful life of pad-mounted switchgear is 20-45 years with a typical useful life of 30 years; however, due to increasing environmental factors, these units have failed at service ages as low as 11 years. Environmental factors such as high humidity, condensation from changing temperatures and water in the below grade foundations when mixed with dirt and road dust contribute to the formation of conductive paths on the insulating components. Over time this ultimately reduces the insulating properties and leads to flashover and failure of the switchgear. This renewal investment is supported by customers based on an increased reliability focus.

In addition, the increasing failure rate of these switchgear means that workers may be at higher risk of being exposed to an arc flash. The planned replacement units would remove this risk. InnPower plans to replace its 25 kV air-insulated switchgear with solid di-electric switchgear rated at 35 kV. This will reduce incidences of failures due to flashover, improve reliability and increase the useful life to 50 years with reduced maintenance and inventory cost.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of switchgear is 30 years. Many units of InnPower's existing switchgear population are approaching that 30 years benchmark and are expected to fail more if not replaced. While age is a factor, InnPower utilizes the results of the ACA to ensure a detailed review is completed prior to selecting candidates for replacement.

InnPower has reached out to many different vendors with the intention of replacing just the damaged enclosure, but the cost of the repair to a twenty (20) to thirty (30) year old asset that is starting to enter the poor condition results based on the ACA was prohibitive in comparison to a new replacement.

Each year InnPower conducts field inspection of switchgears and use the inspection results to update the ACA and to prioritize and select suitable candidates for replacement. Some of the options that are considered when evaluating a switchgear replacement:

i. **Do nothing and run to fail:** Some switchgear units have been run to failure, but this presents a significant reduction in reliability and worker safety. While this is not the preferred method, in some cases, due to budgetary or supply chain constraints, this option is used.

ii. **Like for like replacement:** InnPower no longer purchases air insulated switchgears due to the limited functionality concerns.
iii. **Proactively upgrade to latest standard:** This is the preferred method to align with InnPower approved material, increased functionality leading to increase reliability and faster remotely capable restoration times.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current InnPower specifications and USF design standards which will improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work.
Customer Value	The proactive replacement strategy of the project as planned is less costly than reactive replacements, by reducing outage frequency and outage length, improving communication to customers and by the planned work occurring during regular working hours.
Reliability	This project is part of the long-term replacement program. This will reduce incidences of failures due to flashover, improve reliability, decrease outage time during planned replacements and reduce maintenance and inventory cost.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	Switchgear failures pose safety risk to staff and the public. The switchgear may fail when staff are working on the unit or when the public is in close proximity to the unit. When the switchgear unit fails, there may be flashover or rupture of the enclosure, which may result in injury.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower is experiencing an increasing rate of decline in reliability on its distribution system. Defective equipment is the leading cause of controllable outages in the distribution system.

i. Main Driver: Failure Risk – the main drive is to address assets at end of service life and at risk of failure, as identified through annual inspections and the ACA results.
ii. Secondary Drivers: System operational objectives including safety, reliability and increase functionality.
iii. Information Used to Justify the Investment: The deterioration of legacy switchgear is increasingly contributing to the lack of access InnPower has to perform switching during planned and unplanned work, increasing outage times and restoration efforts. The public and worker safety of having enclosures that are damaged are elevated unit replacement can take place. Additional reference information on the prioritization factors used for switchgears and the condition results is included in the DSP (Section 5.3.2.2.2) and in Appendix J – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower constructs all new projects using approved construction standards complying with ESA Regulation 22/04.

ii. Cost-Benefit Analysis: Keeping pace with projected failure rates strikes a balance between risk and cost. While the cost of the proposed spend is greater than historical spend, it is consistent with customers' preference for improving reliability.
iii. Historical Investments & Outcomes Observed: Historical costs are outlined in Section A3 of this document. Inflation, supply chain material costs also have an impact on the overall costs. The proactive replacement strategy of the project as planned is less costly than reactive replacements. This project has helped improve reliability & minimize outage impacts to customers and reduce safety risks in the past.
iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSS08 – COMMUNICATION IMPROVEMENT

INVESTMENT CATEGORY:

SYSTEM SERVICE

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower and it partner organizations have a Real Time communication set up with all their stations. Presently, InnPower has ten (10) Distribution stations and twenty-three (23) Telemetry Switches in the field. These Real Time communications not only help InnPower to enhance the overall reliability and quality but also improves response time to outages as they arise.

In order to initiate a self reheeling system in future, InnPower plans to add more telemetry devices connected to its SCADA system. For this purpose, the base of these communication systems is dependent on the existing WIMAX/Point to Point 1.8/18/23 GHz system.

InnPower is currently maintaining 14 point-to-point DragonWave 18/23 GHz radios and 10 point-to-multi point 1.8GHz Base Stations at more than 50 active subscriber stations (WIN CPE). Both point-to-point and point-to-multi point communication systems are utilizing 6 HUB NOKIA 800 switches which are at their end-of-life. The 14 point-to-point Compact+ DragonWave radios are also reaching end of life capabilities. InnPower has minimal spares inventory to support replacing these end-of-life assets, which is further driving the need for improvements.

InnPower is planning to replace two (2) switches and two (2) radios each year from 2024 to 2026. InnPower will replace four (4) radios each year in 2027 and 2028. The annual forecast cost is consistent across the forecast period, with increases accounting for inflation as presented in Section A3 of this document.

2. Timing

i. Start Date: 2024

ii. In-Service Date: 2024 to 2028

iii. Key factors that may affect timing: The following factors can impact the project schedule:

- Customer delays or restricted access to work sites;
- Inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- Delays to material shipment from vendors;

- General unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms; and
- Risks to eliminating the outages and communication interruptions.

InnPower has utilized coordination with third parties to mitigate some of these issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	0	16	272	0	0	78	79	81	83	86
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	16	272	0	0	78	79	81	83	86

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The historical costs have been provided in Section A3 above. The average annual investments proposed is to replace units based on reliability.

This project is the continuation of InnPower's long-term annual communication improvement initiative facilitating the improvement in communication and reliability.

InnPower added one repeater site to its system in 2021. This not only increased the system reliability and line of sight for the stations with poor reception but also completed the ring in the system (i.e., multi directional communication). This became the basis for InnPower to implement the spanning tree rules in the system beyond this period.

The spanning true rule applies to the HUB 800 switches, which is not supported anymore due to these assets being at the end of their useful life. Therefore, InnPower is planning to replace these assets over the next 5 years to ensure all the assets are supported by the manufacturer.

6. Investment Priority

This investment has been scored at 64.91. Town of Innisfil utilities include the power, water and waste water communication system. These rely on the wireless (WIMAX) communication systems at 5 out 6 main hub locations and one spare is required for an upgrade or replacement due to the asset being at the end of its useful life.

This investment is crucial in enabling the continued efficient and safe operation of the network. Therefore, this investment is classified as one of the prime priorities.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

InnPower considered the following options:

i. **Do Nothing:** Doing nothing is not a viable option. Both of the existing equipment types for switches and radios have reached end of life and risk of failure. This would impede InnPower's ability to carry out necessary operations and reduces communication and outage response capabilities.

ii. **Carry out proposed pacing of investments:** This is the preferred option as it allows InnPower to invest in the improvements to equipment necessary to carry out the communication and outage response requirements for InnPower's network. Some project specific alternatives may be considered on a case-by-case basis but proceeding with the proposed investment is the prudent alternative.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By having a functioning communication system, InnPower can quickly respond to issues / outages. Without these, InnPower would not have visibility into the issues / outages and would have to rely on a customer reporting issues, or crews identifying issues when out doing other work. The infrastructure will be upgraded to current standards, and this will improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work.
Customer Value	The proactive replacement strategy of the project as planned is less costly than reactive replacements. With a robust communication system, InnPower is able to monitor and manage the grid effectively, identifying and responding to issues more effectively. This significantly improves the customer value. Additionally, this reduces the OM&A cost by facilitating remote inspection and troubleshooting the equipment (running a battery test or determining equipment health) along with monitoring safety features such as gate control, fire alarms and temperature monitoring.
Reliability	This project is part of the communication reliability for the Town utilities (Hydro, Water and Waste Water). Real Time monitoring and recording of data for all three utilities not only helps utilities to control the quality of services provided to customers but also helps InnPower to restore/identify the outages quicker which improves reliability in whole system. Also, this reduces OM&A cost considering less truck rolls, labors, and inspections.
Safety	Communication failure can cause huge impact on equipment, staff, and public safety. With real time monitoring, the system utilities can be notified ahead in time to eliminate any unforested issues that can cause interruptions or impact the quality of the

Primary Criteria for Evaluating Investments	Investment Alignment
	services being delivered to the customers. These systems not only provide live notification and can dispatch crews immediately but also helps in monitoring safety aspects such as gate control, fire alarms, and temperature monitoring.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower forecasts that communication equipment failures on its distribution system would result in decreasing reliability and outage management. Defective equipment is the leading cause of controllable outages in the distribution system. InnPower has seen improvements in reliability and the speed in which response to outages can occur dueto remote capabilities associated with improved communication equipment.

i. Main Driver: Failure risk - Communication in-service is now obsolete and no longer supported by the manufacturer; with only one spare communication equipment improvement is required.

ii. Secondary Drivers: Functional obsolescence and reliability through new equipment capabilities to support better spanning rules and automation of outage restoration.

iii. Information Used to Justify the Investment: The impact of losing communication in the system is very high, as coordination with Hydro One operations is impacted. Financial information is provided by a budgetary quote and estimated labour and machinery costs to support the investment.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower has been utilizing the WIMAX system since 2014 and it is one of the most reliable ways of telemetry communication in the industry. However, this equipment is no longer supported by manufacturers and has increased risk of failure which has significant impacts to the

operations of InnPower's system. InnPower is being proactive in its balanced plan to replace systems over a period of time before major failures occur. Industry practice has deemed replacement of communication equipment is reasonable within the 8-10 year timeframe.

ii. Cost-Benefit Analysis: InnPower has identified that improving communication equipment in the system would reduce OM&A costs while increasing reliability. This is achieved through having real time access to the field devices to monitor the health and status. For InnPower, faster restoration, minimizing truck roll, crew dispatch time and improved power quality monitoring would be realized if proceeding with this program.

iii. Historical Investments & Outcomes Observed: InnPower experienced significant improvements during the execution of this project in the previous years such as maintaining of reliability, ability to identify issues before or as they happen, dispatching crews to respond and thereby minimizing any impacts to the public safety and customers. InnPower has started improving the communication system by adding one site to its system in 2019 / 2021 and completing 2 rings. The implementation of spanning tree has begun since then. Owing to these benefits, InnPower plans to continue monitoring, evaluating, and executing this project in the future.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSS12 – STATION REHAB

INVESTMENT CATEGORY:

SYSTEM SERVICE

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower replaces or rehabilitates its distribution station asset according to Asset Condition Assessment (ACA) results, test reports and inspection results. Assets classified to be in poor and very poor condition are considered as high priority and assets listed to be in fair and good conditions are forecasted to be replaced/repaired later in the future. InnPower conducts monthly field inspection of all the station's assets along with oil sampling (twice a year) and Infrared (IR) testing (once a year) to support assessment of assets requiring replacement or rehab review.

Historically, in 2019 InnPower completed expansion projects to accommodate forecasted loads in Innisfil Area (Friday Harbour) through recoverable projects. This consisted of three (3) station expansions and one Distribution Station (DS) conversion from 8.32kV to 27.6kV system by 2020.

Due to a very poor asset condition of Innisfil DS and increased load in the area, InnPower completed a full station rehabilitation in 2021. In 2022, InnPower has completed a rehabilitation program on one of the power transformers that was taken out of service from Innisfil DS and keep that power transformer as a spare for emergency.

For future years, major assets such as Power Transformers listed in the ACA as poor or very poor condition are high priority assets and InnPower has plans to rehabilitate them in the next 5 years. Other assets such as ground grid, foundations and switches are also considered in the forecasted budget. By the end of the forecast period, InnPower will bring all the assets currently classified within the poor and very poor condition categories into the good and very good condition categories through this program.

To support load growth in Innisfil and south Barrie area, InnPower also plans to expand three (3) stations in the 2023-2025 timeframe to accommodate the forecasted incremental load increase. One station expansion and one transformer upgrade are planned to be completed in 2024. Due to the load growth in the area all of the 2024 expansions are considered mostly recoverable by funding through capital contribution. However, this will be assessed through the economic evaluations InnPower caries out to determine the actual contributions.

InnPower also plans to add oil containment systems for four remaining stations and bury the incoming and outgoing feeders in the stations, in order to increase the reliability and improve safety to public and environment.

2. Timing

i. Start Date: Spring and Fall of each year from 2024 to 2028.
ii. In-Service Date: 2024 to 2028
iii. Key factors that may affect timing: The following factors can impact the project schedule:

- Customer delays or restricted access to work sites;
- Inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- Delays to material shipment from vendors, and
- General unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

InnPower has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	21	276	2,194	2,683	2,030	393	4,979	3,100	4,948	468	625	644
Contributions	0	0	(1,783)	(2,607)	(17)	0	(4,875)	(3,100)	(4,720)	0	0	0
Capital (Net)	21	76	411	76	2,013	393	104	0	228	468	625	644

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

According to the load growth in Innisfil and south Barrie area, InnPower plans to expand 3 stations in the 2023-2025 timeframe to accommodate the incremental load. These station expansions are due to both historical organic load growth in the system along with a forecasted increase in demand in this part of InnPower's service area over the next 5 years. One of the three station expansions is scheduled to be completed in 2024. As the driver for these expansions is load growth, InnPower anticipates most of the costs to be recoverable through contributions.

4. Economic Evaluation (Expansion Projects)

InnPower carries out economic evaluations to determine the capital contribution to be paid by the third-party. Once proposed load demand is finalized, and projects scoped out, the economic evaluations will be carried out.

5. Comparative Historical Expenditure

Historical costs have been documented in Section A3 above. This project is the continuation of InnPower's long-term station rehabilitation initiative and investments are based on inspection results. InnPower will keep improving the system after the second expansion period (2023-2025) according to its ACA result. All these expansions are required to meet the load demands for the short and mid term period.

The increase in the expenditures from 2019 to 2021 can be attributed to the fact that starting 2019, InnPower completed recoverable expansion projects to accommodate forecasted loads in Innisfil Area (Friday Harbour). This consisted of expansions, upgrade of 3 stations and converting/rebuilding one DS from 8.32kV to 27.6kV system by 2020. Due to a very poor asset condition of Innisfil DS and increased load in the area, InnPower completed a full rehab at this station in 2021.

The drop in expenditures in 2022 is justified because of prioritization to the rehabilitation program completed by InnPower on one of the power transformers that was taken out of service.

6. Investment Priority

This is considered a high investment priority and has a priority score of 1,192.74. A portion of the station equipment is at end-of-life and requires replacement in order to maintain system integrity and reliable service to the growing load demand of new and existing customers. If not replaced, the equipment will age and fail more often to the level that is not manageable by InnPower and not tolerable by the customers. InnPower plans to proactively evaluate / manage end of life assets and replace them to avoid huge service interruptions.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

InnPower considered several alternatives in order to meet the objectives of this program / project.

i. **Do Nothing or Run-to-Failure:** Not doing anything and running assets in poor or very poor conditions to failure will have significant impact on system reliability, safety, and customer value. This approach will not allow InnPower to meet growing demand for service in the area and is not considered a feasible option.
ii. **Proactive Replacement / Rehab:** Assets which are in poor condition needs immediate proactive action. Therefore, assets such as power transformer will be replaced or sent for rehab according to ACA, test report and visual inspections. In most of the planned station's rehabs InnPower send the power transformers (the major asset) for refurbishment to defer the need of bigger investment of replacement. However, some assets such as foundation, ground grids and switches need to be replaced during the project construction. Hence, this option was also not favoured.

iii. **Expansions:** In addition to proactive replacement / rehab projects, InnPower assessed the expansion projects option. This is the required alternative to accommodate the forecasted loads in short/mid terms. InnPower reviewed different alternatives such as non wire solution to shave the peak demand as well as the do nothing solution but economically and practically all the other alternatives other than to do an expansion failed due to significant load increase forecasted in the system.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be expanded and upgraded to current standards enabling InnPower to meet capacity demands and will help improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work.
Customer Value	The proactive replacement strategy of the project as planned is less costly than reactive replacements and avoid additional outages on the system.
Reliability	During few rehab/replacement projects, InnPower believed that the proactive projects based on engineering analysis from ACA, test reports and inspections would help InnPower to make prioritized and informed investments towards these projects that could prevent catastrophic damages and outages.

Primary Criteria for Evaluating Investments	Investment Alignment
	Hence, this project has a direct impact on reliability improvement.
Safety	Stations' failures pose safety risk to staff and the public. The stations may fail when staff are working in the station or when the public is in close proximity to the station. Additionally, during recent inspections it was observed that some stations required upgrade and additional environment protection such as oil containment system. This helps to improve the staff/public safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower is experiencing an decline in reliability on its distribution system. Defective equipment is the leading cause of controllable outages in the distribution system.

i. Main Driver: Load growth - InnPower is forecasting an increase in load growth that requires investment to be able to manage and meet the new load.
ii. Secondary Drivers: Reliability, system efficiency and safety.
iii. Information Used to Justify the Investment: Information such as forecasted load demand, Asset Condition Assessments (ACA), inspections, and test results are used to inform these project expenditures.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

iv. Demonstrating Accepted Utility Practice: InnPower constructs all new projects using approved construction standards complying with ESA Regulation 22/04, IEEE and ANSI when applicable.
v. Cost-Benefit Analysis: InnPower believes that keeping pace with projected inspection results and ACA strikes a balance between risk and cost. While the cost

of the proposed spend is greater than historical spend, it is consistent with customers' preference for maintaining reliability in line with historical levels.

vi. Historical Investments & Outcomes Observed: The proactive replacement strategy of the project as planned is less costly than reactive replacements. As part of the historical stations rehab project, in 2021/2022, an Innisfil DS Power transformer had been sent for refurbishment and it was classified as a significant risk that would have resulted in a vast outage and a catastrophic failure. InnPower engineers prevented the damages to the assets and eliminated the risk of a huge power outage to InnPower customers thereby increasing the reliability.

vii. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSS17 – BARRIE AREA TRANSFORMER UPGRADE (BATU)

INVESTMENT CATEGORY:

SYSTEM SERVICE

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower is completing the Barrie Area Transformer Upgrade (BATU) project to support the Hydro One-led project which had been approved through Hydro One Network Inc's (HONI) filing with the OEB (EB-2018-0117). InnPower is providing a capital contribution for its scope in the project, which is being incurred within the DSP forecast budget and triggers this material narrative.

The IESO Regional planning study by local stakeholders identified a need for capacity increase in the Barrie area, in particular InnPower's 25-year forecast showed that the existing capacity of 115kV E3B/E4B circuits and Barrie TS was not adequate for future loading thereby requiring uprating of assets from 115kV to 230kV. To update assets from 115kV to 230kV requires the below projects and subsequent scope of work:

Table 1: Aspects of the BATU Project

Project	Description
Essa TS	• Expand the existing 230kV yard to accommodate the new 230kV transmission lines (breakers, switches, bus). • Reconfigure the existing 230kV lines inside the station. • Removal of two existing 230/115kV auto transformers and associated 115kV switchyard infrastructure currently used to supply Barrie TS.
Barrie TS	• Upgrade and expand the existing Barrie TS yard from 55/92 MVA with new 230/44kV station facilities, consisting of two new 75/125 MVA transformers and a new 44kV switchyard. • Remove all 115kV equipment.
Transmission Lines	• Construct a new 230kV double circuit transmission line between Barrie TS and Essa TS. This new line will be designated as E28 and E29. • Remove the old 115kV circuits E3B and E4B.

The BATU project is undergoing material changes and in-service delays. The initial in-service date for the project was June 2022 with an OEB approved total project cost of $91M, including $14.1M in capital contributions from InnPower. However, due to changes in project scope, procurement delays based on market conditions, supply chain constraints, and commodity pricing, the initial project in-service date has been pushed

by 18 months to December 2023. As such, the total estimated cost of the BATU project is now $125M, with InnPower's capital contribution expected to increase to $20.6M. The capital contribution estimate is derived from the total project cost estimates provided in April 2022, calculated by Hydro One and provided to InnPower.

More information on the current status of assets installed as part of the BATU project can be found in Section 5.4.1.2 of the DSP.

2. TIMING

i. Start Date: 2020

ii. In-Service Date: 2023

iii. Key factors that may affect timing: InnPower are in close communication with HONI to understand any cost changes and therefore changes to its Capital Contribution. There are a few risks that can potentially impact the project schedule further such as:

- Procurement risk in both cost and schedule based on current market condition, and
- Commodity pricing for long lead time material. (i.e., Conductor and Tower Steel).

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Table 2: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	0	0	0	0	4,099	4,120	4,120	4,120	4,120	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	4,099	4,120	4,120	4,120	4,120	0

4. ECONOMIC EVALUATION (EXPANSION PROJECTS)

HONI completed an assessment to determine capital contributions for this expansion project. To review the economic evaluation, please refer to HONI Section 92 – Barrie Area Transmission Upgrade Project (EB-2018-0117) filed on August 8, 2022.

5. COMPARATIVE HISTORICAL EXPENDITURE

HONI is leading this project including development costs so no comparative historical expenditure is necessary from InnPower.

6. Investment Priority

This is a high priority investment that was scored 1,254.14. The Integrated Regional Resource Planning (IRRP) process identifies power system capacity and reliability requirements and coordinates the options to meet customer needs in the sub-region over the next 20 years. Specifically, BARRIE/INNISFIL SUB-REGION IRRP identifies immediate investments that are required to meet near- and medium-term needs in the sub-region, respecting the lead time for development.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

The alternatives considered are detailed in the application submitted by HONI in 2019 (EB-2018-0117) and approved by the OEB. The comparisons of alternatives are discussed in Exhibit B, Tab 5, Schedule 1 of HONI's application. A summary of the alternatives considered is stated below. The working group has considered three alternatives for addressing the capacity and end-of-life needs at Barrie TS, Essa TS and on circuits E3B and E4B:

i. **Rebuild Barrie TS:** Rebuilding Barrie TS like-for-like with customized transformers, as existing units are no longer a Hydro One standard transformer size; replacing all other end-of-life equipment at Essa TS (including the T1 autotransformer) as well as the aging conductors and poles along circuits E3B and E4B. Although this option addresses end-of-life needs, it does not address near and medium-term capacity need. Hence this option was not selected.
ii. **Decommission Barrie TS:** Decommissioning Barrie TS while building a new 230/44 kV DESN station at Essa TS. From the Essa TS site, the 44 kV feeders would utilize the decommissioned E3B/E4B corridor to re-supply the feeders formerly fed by Barrie TS. This option meets near and medium-term needs, but it will limit options for future expansion of the transmission system to accommodate future capacity increases in the area. Hence, this option was not selected.
iii. **Supply upgrade of Barrie TS to 230 kV:** Rebuild Barrie TS to a 230 kV supply, including the replacement of the existing 115 kV E3B and E4B transmission circuits with 230 kV circuits spanning between Essa TS and Barrie TS to meet the identified load requirements. The existing end-of-life 115 kV switchyard at Barrie TS would be retired and the existing 230/115 kV autotransformers at Essa TS, that supply only Barrie TS load, would also be retired. The rebuilt 230 kV Barrie TS would then be supplied directly from the expanded Essa TS 230 kV system. This option meets near and medium-term needs, as well as facilitates expansion of the transmission system to accommodate future capacity increases in the area. Hence, this option was considered feasible by the Working Group.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Based on the potential demand growth within this Sub-region, expanding the infrastructure capacity supplying south Barrie and Innisfil Area is the most efficient solution.
Customer Value	This investment will help with the growth in south Barrie and Innisfil Area to absorb more jobs and housings in future and as well as provide the required capacity to meet these future demands.
Reliability	This project has direct impact on Transmission reliability as it will ensure reliability standard can be maintained.
Safety	As when asset reaches their end of life, they are more susceptible to unexpected failure, which could cause safety issues to the public and employees. With the Barrie TS being at its end of life, it has direct impact on Public Safety and Equipment Safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: Capacity upgrade and line extension i.e., to accommodate Short- / Mid-term load demand in system and increase sub transmission capacity.

ii. Secondary Drivers: Supply critical customers such as hospitals, commercial and industrial institutions from sub transmission feeders (44kV) level.

iii. Information Used to Justify the Investment: This BATU project is consistent with the transmission solution recommended in the IESO's Barrie/Innisfil Sub-Region IRRP and in the South Georgian Bay/Muskoka Regional Infrastructure Plan ("RIP"). These can be found in Appendices F and G of the DSP. These plans identify near-term and 18 medium-term supply needs in the Barrie/Innisfil Sub-Region. For more information, please refer to the application submitted by Hydro One in 2019 (EB-2018-0117) and approved by the OEB.

3. INVESTMENT JUSTIFICATION

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: IESO Near-term Transmission Project identified through the Barrie/Innisfil IRRP.

ii. Cost-Benefit Analysis: More information on the cost benefit analysis and options can be found in Exhibit B, Tab 5, Schedule 1 of the Hydro One application submitted in 2019 (EB-2018-0117). A summary table of the options considered along with the benefits offered is shown below*:

Table 4: Options Considered and Associated Benefits Offered

Options Considered	Needs Addressed	Status
Option 1 – Like-for-like replacement of EOL equipment at Essa TS, Barrie TS, and on circuits E3B/E4B.	End-of-life needs are addressed. Capacity needs and expandability are not addressed.	Rejected
Option 2 – Decommission Barrie TS, Essa TS 115kV switchyard, and circuits E3B/E4B; and build new DESN at Essa TS and run express distribution feeders on E3B/E4B corridor	End-of-life and capacity needs are addressed. However, long distribution feeders result in lower reliability and increase in losses. Future expandability is not addressed.	Rejected
Option 3 – Rebuild Barrie TS to 230/44kV 75/125MVA DESN, upgrade circuits E3B/E4B to 230kV, decommission Essa TS 230/115kV auto-transformers and 115kV	End-of-life needs, capacity needs, and expandability are addressed.	Recommended

switchyard, and build new 230kV switching at Essa TS to supply new 230kV circuits		

Please note that the above table has been taken from the Hydro One Application submitted in 2019.

iii. Historical Investments & Outcomes Observed: This is a one-off type of project. Historically, this project did not exist, hence the historical expenditures amount to zero (as can be seen in Section A3 of this document). However, moving forward with Option 3 in the forecast years as planned would address the near-term and medium-term capacity needs; remove an aging 115 kV switchyard at Essa TS; and will allow for future expansion capability to supply the region's long-term capacity needs.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

Conservation and demand management was addressed as part of the Barrie/Innisfil Sub-region integration regional resource plan developed by the IESO. No further conservation and demand management assessments were completed by InnPower.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSS24 – NORMAL OPEN POINT SWITCH INSTALLATION

INVESTMENT CATEGORY:

SYSTEM SERVICE

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

InnPower has a program in place to manage the installation and replacement of single phase in-line switches within its distribution system. This project is one of the steps InnPower is taking to modernize its distribution system by adding automation to switching assets. InnPower currently has 362 single-phase in-line normal open point switches in its system. Through this program, InnPower will replace in-line normal open point switches with remote load break-operated switches, which will improve reliability, load transfer and limit truck rolls.

Switches are a distributor's main method of switching loads for system operation and restoring customers after an outage. They are a fundamental tool by which InnPower can sectionalize and isolate parts of the distribution system when needed.

Replacing single-phase in-line switches that are not fit for operation, either because they are functionally obsolete, no longer operable, or otherwise incapable of interrupting the load will allow InnPower to quickly restore service, transfer supply, and enable isolation from the System Control. This will reduce the need for crews to operate reclosers and permit crews to focus on fault identification and repair. Typically, through the automation of these switches, most outages would be restored within a few minutes.

Customers will experience improved reliability because of the sustainment of deteriorated and functionally obsolete assets. Furthermore, InnPower will avoid the safety risks of manual switch operation with live line tools and failure through the installation of remotely controlled switches. InnPower plans to install three (3) units per year over the years 2023 to 2027. This renewal investment is supported by customers.

2. Timing

i. Start Date: This is an annual investment initiative to manage end-of-life assets and to improve system reliability by adding remote operable tie points between different feeders in the distribution system. InnPower is anticipating a completion date of 2027 for this program.

ii. In-Service Date: 2024 to 2027

iii. Key factors that may affect timing: InnPower considers several factors impacting the project schedule including:

- customer delays or restricted access to work sites;
- availability of budgets;

- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms; and,
- delays to material shipment from vendors; and general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

InnPower has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	0	0	0	0	201	221	227	232	238	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	201	221	227	232	238	0

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

This is a new project at InnPower to improve the ability to restore outages remotely, transfer load between feeders and stations and reduce the number of truck rolls required to sectionalize an outage. This program started for the first time in 2023. There are no historical costs associated with this program. The target is to replace three (3) normal open point locations per year.

6. Investment Priority

This is a medium priority investment that was scored 404.83. Overhead switches are a distributor's main method of switching loads for system operation and restoring customers after an outage. Switches are the basic tool by which InnPower can sectionalize and isolate parts of the distribution system when needed.

Replacing deteriorated switches and switches that are not fit for operation, either because they are functionally obsolete, no longer operable, or otherwise incapable of interrupting the load allow InnPower to quickly restore service, transfer supply and enable isolation from the System Control. This will reduce the need for crews to operate switches and permit crews to focus on fault identification and repair.

More information on InnPower's project prioritization process and results can be found in Sections 5.3.1.3 and 5.4.2.1 of the DSP.

7. Alternatives Analysis

Each year InnPower conducts field inspection of switches and use the inspection results to update the Asset Condition Assessment (ACA) and to prioritize and select suitable candidates for replacement. Some of the options that are considered when evaluating a switch replacement are:

i. **Do nothing and run to fail:** This option presents a significant reduction in reliability and worker safety. While this is not the preferred method, in some cases, due to budgetary or supply chain constraints, this option is used. However, this is always assessed to ensure safety issues are mitigated as much as possible.

i. **Like for like replacement (proactive):** This is not the preferred option. InnPower no longer installs single-phase in-line switches at normal open points due to the limited functionality, reliability, and safety concerns.

ii. **Upgrade to the latest standard:** This is the preferred method to align with InnPower's standards, allowing for increased functionality leading to an improvement in reliability and faster remote capable restoration times.

8. Innovative Nature of the Project

This project will modernize InnPower's distribution system by adding automation to InnPower's switching assets. The anticipated benefits of this program include improving reliability, reducing truck rolls, and reducing safety risk. Automated switches are able to identify fault current levels, fault direction and have the ability to be operated remotely without having the need for a truck roll. This can either assist with sectionalizing an outage to a small area or transfer loads between stations. Typically, this will mean that most outages will be able to restore remotely within a few minutes. This will drive significant benefits to customers, reduce truck rolls and improve reliability.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current InnPower specifications and design standards, will improve reliability, and reduce the need for truck rolls and the costs associated with this, allowing for crews to focus other priority work. Proactive upgrade replacements of an asset are more cost-effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. In addition, manual single-phase in-line switches required crews to attend to operate the switch, whereas with automation installed this can be mitigated and cost savings achieved.
Customer Value	Customers will experience improved reliability as a result of the sustainment of deteriorated and functionally obsolete assets. InnPower will avoid the safety risks of manually operated switch failure through the installation of remotely controlled switches. The safety risks associated with legacy single phase in-line switches, which cannot be operated under non-balanced load will also be eliminated as these switches are removed from the system. The enablement of automation will allow InnPower to quickly restore customers when an outage occurs, typically within a few minutes. This renewal investment is supported by customers.
Reliability	This project is part of the long-term replacement program. Reliability will be adversely affected when a switch fails to operate when required to restore service. Automated switches provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak, provide real-time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	Automated switches provide rapid transfer of loads in emergencies, reduce restoration time which improves reliability, provide flexibility to reconfigure the system to avoid feeder and station overloads during summer peak, provide real time system readings, reduce the risk of personnel injury and are the platform for the complete distribution automation system. Proactively replacing identifying switches mitigates the risk of the assets failing in service and controls the hazards to a reasonable level.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

InnPower has a responsibility to improve reliability of its customers on its distribution system. Defective equipment is the leading cause of controllable outages in the distribution system, including switches.

i. Main Driver: Reliability and asset failure risk- This is the main driver due to assets being at the end of their service life. Should these assets fail, it can have a significant impact on the reliability customer's experience.
ii. Secondary Drivers: System Operational Objective: System Efficiency – the new switches will have remote operability enabled which will allow for improved safety by reducing the need for manual switching and quick restoration outages. Automation also allows for the reduction of truck rolls.
iii. Information Used to Justify the Investment: Switches are a distributor's main method of switching loads for system operation and to restore customers after an outage. Switches are the basic tool by which InnPower can sectionalize and isolate parts of the distribution system when needed. Single phase normal open points require a thorough process to make and break load due to the nature of having the other two phases energized. A gang-operated load breaking device significantly reduces the time for switching, sectionalization and restoration. Upgrading these normal open points between feeders allows InnPower to restore, switch and transfer loads more efficiently while minimizing truck rolls. Upgrading these assets further mitigates failure risk of an asset supporting the main driver for this investment.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: InnPower constructs all new projects using approved construction standards complying with ESA Regulation 22/04. This will ultimately reduce truck rolls; significantly limit safety impacts to crews; and enhance the overall reliability.
ii. Cost-Benefit Analysis: InnPower believes that implementing this project strikes a balance between risk and cost. Three (3) switches per year will be upgraded as per the latest standards. The benefits offered by this annual upgrade strategy are purely in improving reliability and safety (i.e., limiting truck rolls, reducing truck drive times, isolating outage/safety hazards quicker). This project is consistent with customers' preference for improving reliability and reducing worker safety risks.
iii. Historical Investments & Outcomes Observed: This is a new program that will span from 2023 to 2027 to upgrade all normal open points in the InnPower distribution system by removing obsolete and manual single-phase in-line switches.
iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

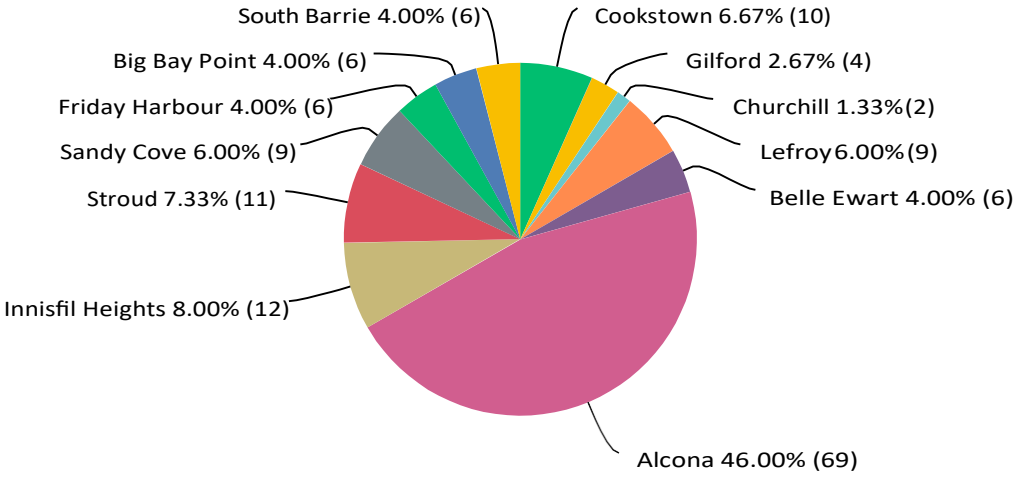


Appendix B

Customer Priority Survey Results

Q1 Please select which area of InnPower's service territory that you reside in or are located nearest to.

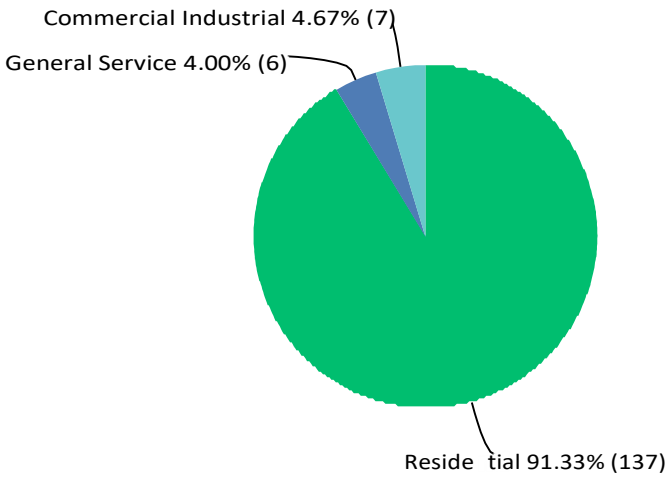
Answered: 150 Skipped: 0



ANSWER CHOICES	RESPONSES	
Cookstown	6.67%	10
Fennels Corner	0.00%	0
Gilford	2.67%	4
Churchill	1.33%	2
Lefroy	6.00%	9
Belle Ewart	4.00%	6
Alcona	46.00%	69
Innisfil Heights	8.00%	12
Stroud	7.33%	11
Sandy Cove	6.00%	9
Friday Harbour	4.00%	6
Big Bay Point	4.00%	6
South Barrie	4.00%	6
TOTAL		150

Q2 Please select the type of electric account you have with InnPower.

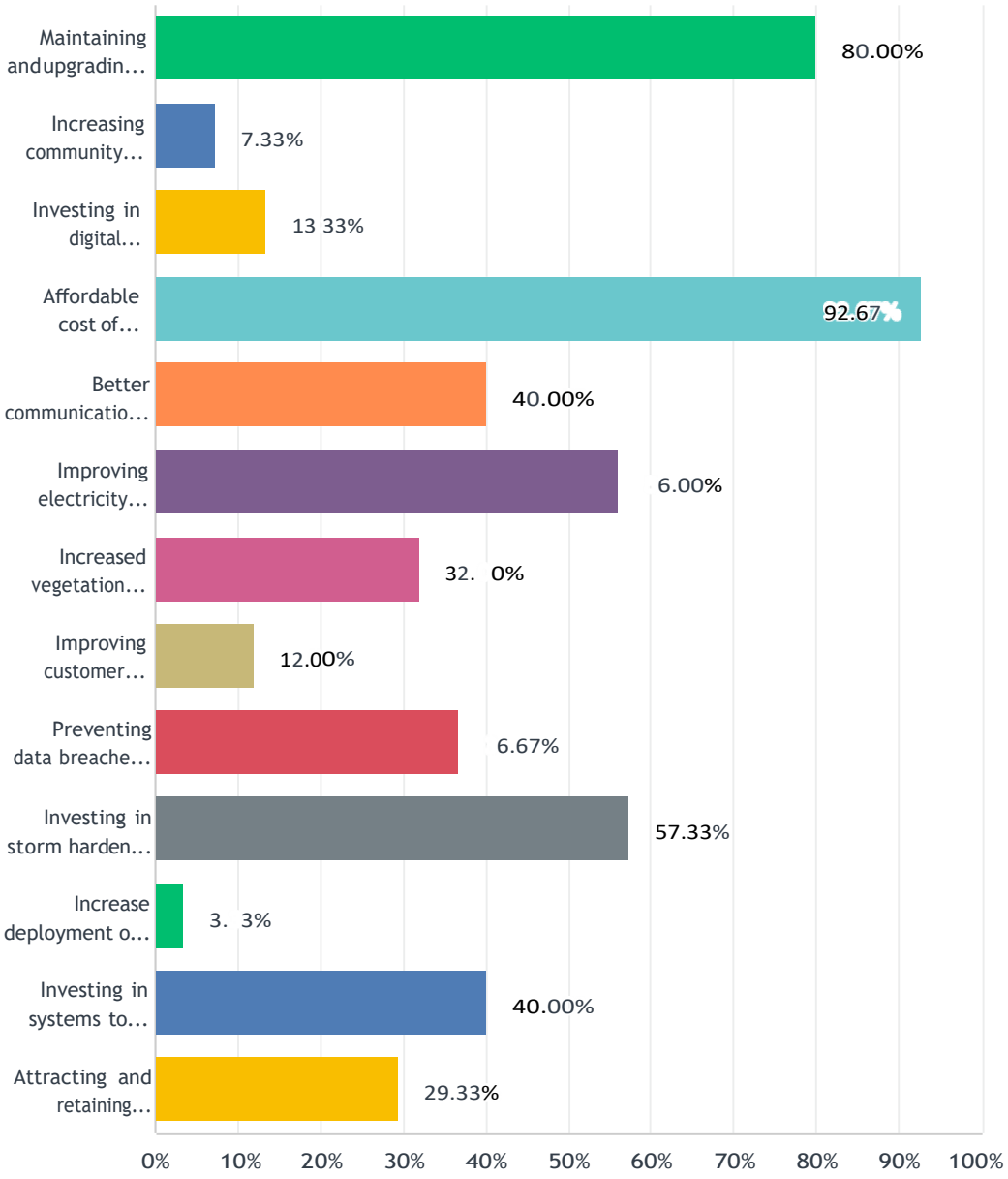
Answered: 150 Skipped: 0



ANSWER CHOICES	RESPONSES	
Residential	91.33%	137
General Service	4.00%	6
General Service > 50 kW	0.00%	0
Commercial Industrial	4.67%	7
TOTAL		150

Q3 Review the options below. Please select the 5 options that are most important to you.

Answered: 150 Skipped: 0



ANSWER CHOICES	RESPONSES	
Maintaining and upgrading equipment to ensure a safe and reliable electricity supply	80.00%	120
Increasing community involvement	7.33%	11
Investing in digital solutions to enhance customer service	13.33%	20
Affordable cost of electricity	92.67%	139
Better communication from InnPower when electricity outages occur (outage map, social media, etc.)”	40.00%	60
Improving electricity outage Response time	56.00%	84
Increased vegetation management efforts (clearing trees and brush around powerlines for increased safety and reliability)	32.00%	48
Improving customer education (on topics such as electrical safety, financial assistance, energy conservation, etc).	12.00%	18
Preventing data breaches and system disruptions due to cyberattack	36.67%	55
Investing in storm hardening (physical improvements that can make utility infrastructure more resistant to weather)	57.33%	86
Increase deployment of Distribution Automation	3.33%	5
Investing in systems to accommodate new technologies (renewable energy generation, electric vehicles, charging stations, etc.)	40.00%	60
Attracting and retaining highly skilled employees to deliver the best service	29.33%	44
Total Respondents: 150		



Appendix C

Needs Assessment Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

South Georgian Bay - Muskoka

Date: April 30, 2020

Prepared by: South Georgian Bay - Muskoka Region Study Team

Transmission & Distribution

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the South Georgian Bay - Muskoka Region and to recommend which need may be a) directly addressed by developing a preferred plan as part of NA phase and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Study Team for this region.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION South Georgian Bay (SGB) – Muskoka (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: January 30, 2020 **END DATE:** April 30, 2020

1. INTRODUCTION

The first cycle of the Regional Planning process for the South Georgian Bay (SGB) - Muskoka Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This is the second cycle of regional planning starting with a Needs Assessment ("NA"). The purpose of this NA is a) to identify any new needs and/or to reaffirm needs identified in the previous SGB-Muskoka Regional Planning cycle and b) recommend which need may be a) met more directly by distributors or other customers and their respective transmitter b) identify needs requiring further assessment and/or regional coordination.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of these timelines, the 2nd Regional Planning cycle was triggered for SGB-Muskoka Region.

3. SCOPE OF NEEDSASSESSMENT

This assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region: and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region.
- Identify needs that will require further coordination at the regional level and those which can be met more directly by distributors and other customers as their respective transmitter.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

As per the PPWG Regional Planning Report to the Board (May 2013), the planning horizons of regional facilities are typically considered over 1-20 years; however, in most situations focus is over the 1 – 10-year timeframe.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for this Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment methodology includes review of planning information such as load forecast, conservation and demand management ("CDM") forecast and available distributed generation ("DG") information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their life.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its life.

6. NEEDS

I. Needs Identified from Previous Cycle – Implementation Plan Update

i. Barrie TS transformer supply capacity will be exceeded, and consequently result in thermal violation of the radial supply circuits (E3B/E4B). The majority of equipment at Barrie TS as well as the Essa TS 115kV yard have also been assessed at being end of life and in need of replacement due to asset condition. This resulted in creation of the Barrie Area Transmission Reinforcement (BATU) project to address these needs. This investment in presently underway with an in-service date scheduled for 2022.

ii. Parry Sound TS transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to asset condition. Hydro One will be installing new 230/44kV 83MVA transformers to address both end of life and supply capacity needs. The In-service is scheduled for 2024.

iii. Loss of M6E and M7E will result in violation of ORTAC load restoration criteria based on the peak load forecast. To adhere to the criteria, Hydro One will be installing 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time. The In-service is scheduled for 2021.

iv. Minden TS – Replace 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units. These transformers have been assessed at being end of life and in need of replacement due to asset condition. The In-service scheduled is for 2021.

v. Orangeville TS – Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing non standard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. These transformers and associated low voltage equipment has been assessed at being end of life and in need of replacement due to asset condition. This is presently underway with an In-Service scheduled for 2023.

II. Newly Identified Needs in the region

i. Waubaushene TS - This station will exceed its normal supply capacity at the end of 2020 based on the summer demand forecast. An immediate solution is required to address the summer loading concern and shall be coordinated with a permanent solution to address long term supply capacity needs. As well, the transformers are expected to be at the end of the study period and require replacement by 2030.

ii. Everett TS – Load growth at this station is restricted due to a limiting component within the low votage yard. This will be need to be corrected by 2026 to allow load to continue growing as per demand forecast.

iii. Barrie TS - This station will exceed its normal summer and winter supply capacity in 2024 and 2026 respectively, based on the existing 115/44kV transformers installed. The Barrie Area Transmission Project (BATU) will be completed in 2022, and help to address existing capacity, and end of life issues that have been identified in the first RP cycle. Although supply capacity appears to be available post-BATU, Hydro One Distribution and its embedded LDC (InnPower) will be constrained at the 44kV feeder supply level in 2025. A plan is required to address the supply capacity need from InnPower beyond what Barrie TS can provide.

iv. Parry Sound TS - This station will exceed supply in 2020 based on the winter demand forecast. Hydro One will be upgrading the transformers with two new 230/44kV 83MVA units in 2024. A solution is required to address the immediate station capacity need.

v. Sections of M6E/M7E are at end of life and in need of replacement – Refurbish 25km of 230kV transmission line from Orillia TS x Coopers Falls JCT – In-Service 2024

Sections of E8V / E9V are at end of life and in need of replacement – Refurbish 56km of 230kV transmission line from Orangeville TS x Essa JCT – In-Service 2027

Sections of D1M / D2M are at end of life and in need of replacement – Refurbish 62km of 230kV transmission line from Minden TS x Otter Creek JCT - In-Service 2028

vi. M6E/M7E (Essa TS x Midhurst TS) thermal overloading - With four Des Joachims GS units out of service the subsequent loss of either M6E or M7E will result in the companion circuit to exceed its LTE (Long

Term Emergency) rating on the line section from Essa TS x Midhurst TS. This overload occurs as early as 2023.

7. RECOMMENDATIONS

i. Waubaushene TS – Hydro One will coordinate with the connected LDC and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within the next year. Permanent solution(s) will require further regional coordination to verify if non-wires options would be beneficial. Further regional coordination is required.

ii. Everett TS – Full utilization of the station transformer capacity is restricted by a series limiting component. A CT ratio setting on the low voltage bushing of the transformer breaker can be modified to allow full transformer LTR capability. Hydro One will initiate a project directly in collaboration with the LDCs as soon as practical. Further regional coordination is not required.

iii. Barrie TS – The Barrie Area Transmission Upgrade (BATU) project is presently underway with a planned in service of 2022. No further coordination is required for the BATU project.

The working group will continue to develop supply capacity solution(s) for Innisfil area load growth. Further regional coordination is required.

iv. Parry Sound TS – The station transformer upgrade is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers. No further regional coordination is required.

v. M6E/M7E (Essa x Midhurst) Overloading – Further regional coordination is required.

vi. Replacement of end of life assets (section 8.1 e.f.g) require further regional coordination.

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2 INTRODUCTION

The first cycle of the Regional Planning process for the South Georgian Bay - Muskoka Region was completed in July 2016 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous SGB-Muskoka regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the South Georgian Bay - Muskoka Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: SGB-Muskoka Region Study Team Participants

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator ("IESO")
Hydro One Networks Inc. (Distribution)
Alectra Utilities
InnPower
Orangeville Hydro
Elexicon Energy
Lakeland Power
EPCOR Electricity Distribution Ontario Inc.
Newmarket-Tay Power Distribution Ltd
Orillia Power Distribution Corp.
Wasaga Distribution Inc.

3 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of Regional Planning cycle timelines and new needs in the SGB-Muskoka region, the 2nd Regional Planning cycle was triggered for the SGB-Muskoka region.

4 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the SGB-Muskoka region and includes:

- Review the status of needs/plans identified in the previous RIP; and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

5 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The geographical area of the South Georgian Bay/Muskoka Region is the area roughly bordered by West Nippising on the North-West, the Algonquin Provincial Park on the North-East, Scugog on the South, Erin on the South-West, and Grey Highlands on the West. This region is divided into two sub-regions:

- Barrie/Innisfil Sub-region: This area encompasses the City of Barrie, the Towns of Innisfil, New Tecumseth and Bradford West Gwillimbury, and the Townships of Essa, Springwater, Clearview, Mulmur, and Adjala-Tosorontio.
- Parry Sound/Muskoka Sub-region: This area encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County.

The boundaries of South Georgian Bay - Muskoka Region is shown below in Fig. 1.

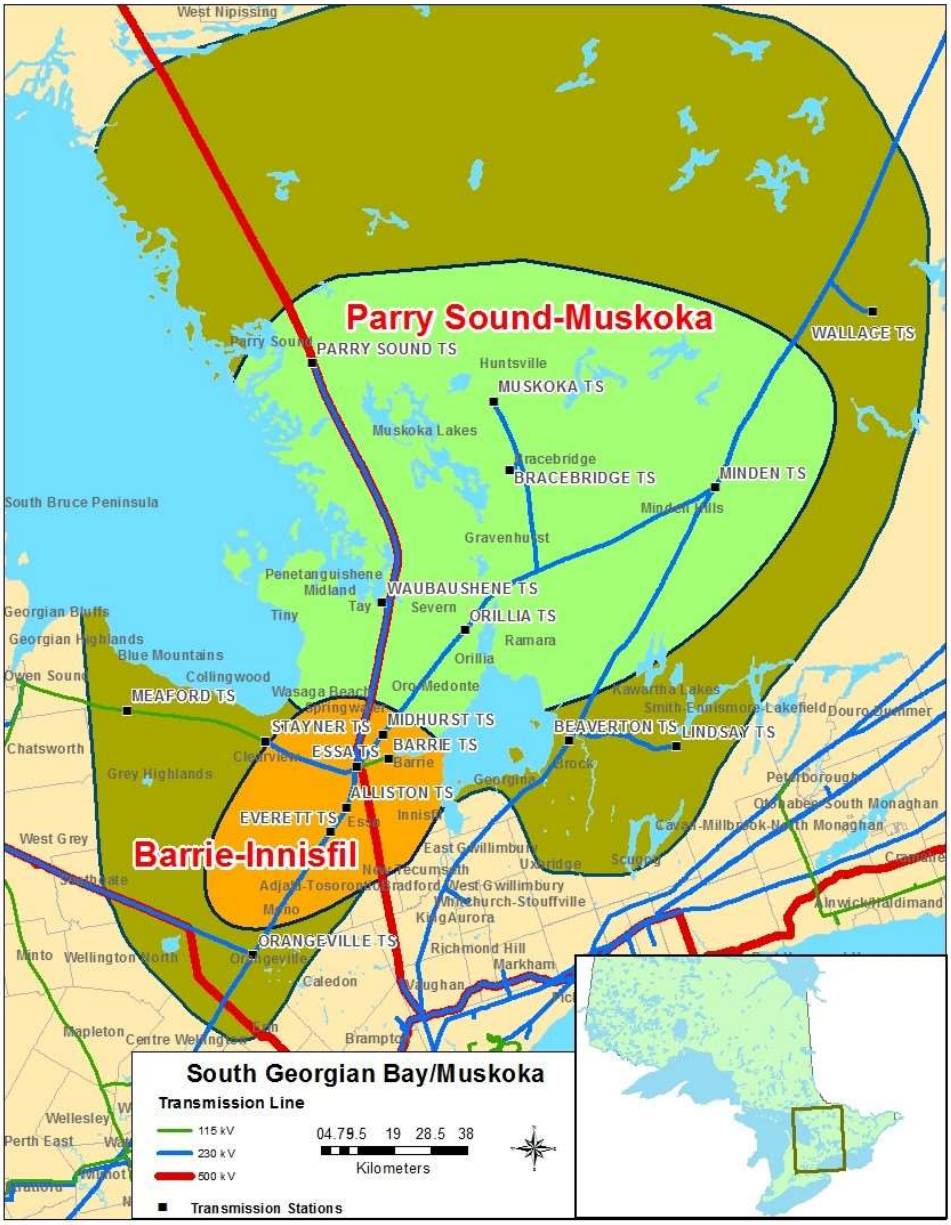


Figure 1: Geographical Area of SGB-Muskoka Region with Electrical Layout

Electrical supply to the Region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The following circuits are not included in the South Georgian Bay/Muskoka Region:

• The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.
• The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

• Essa TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230kV auto-transformers. Essa TS also supplies the 115kV system towards Barrie TS via two 230/115kV auto-transformers.

• Eleven step-down transformer stations supply load to the north and east areas of the Region (north and east of Essa TS): Barrie TS, Beaverton TS, Bracebridge TS, Lindsay TS, Midhurst TS, Minden TS, Muskoka TS, Orillia TS, Parry Sound TS, Wallace TS, and Waubashene TS.

• Five step-down transformer stations supply load to the south and west areas of the Region (south and west of Essa TS): Alliston TS, Everett TS, Meaford TS, Orangeville TS, and Stayner TS.

• Eight 230kV circuits (E8V, E9V, E20S, E21S, E26, E27, M6E, and M7E) radiating outward from Essa TS provide local supply to the Region. These circuits are essential to the Region and will be included in the study to ensure long-term reliability. Four 230kV circuits (D1M, D2M, D3M, and D4M) entering the region from the east are also a major supply path for the Region and will be analyzed in this study.

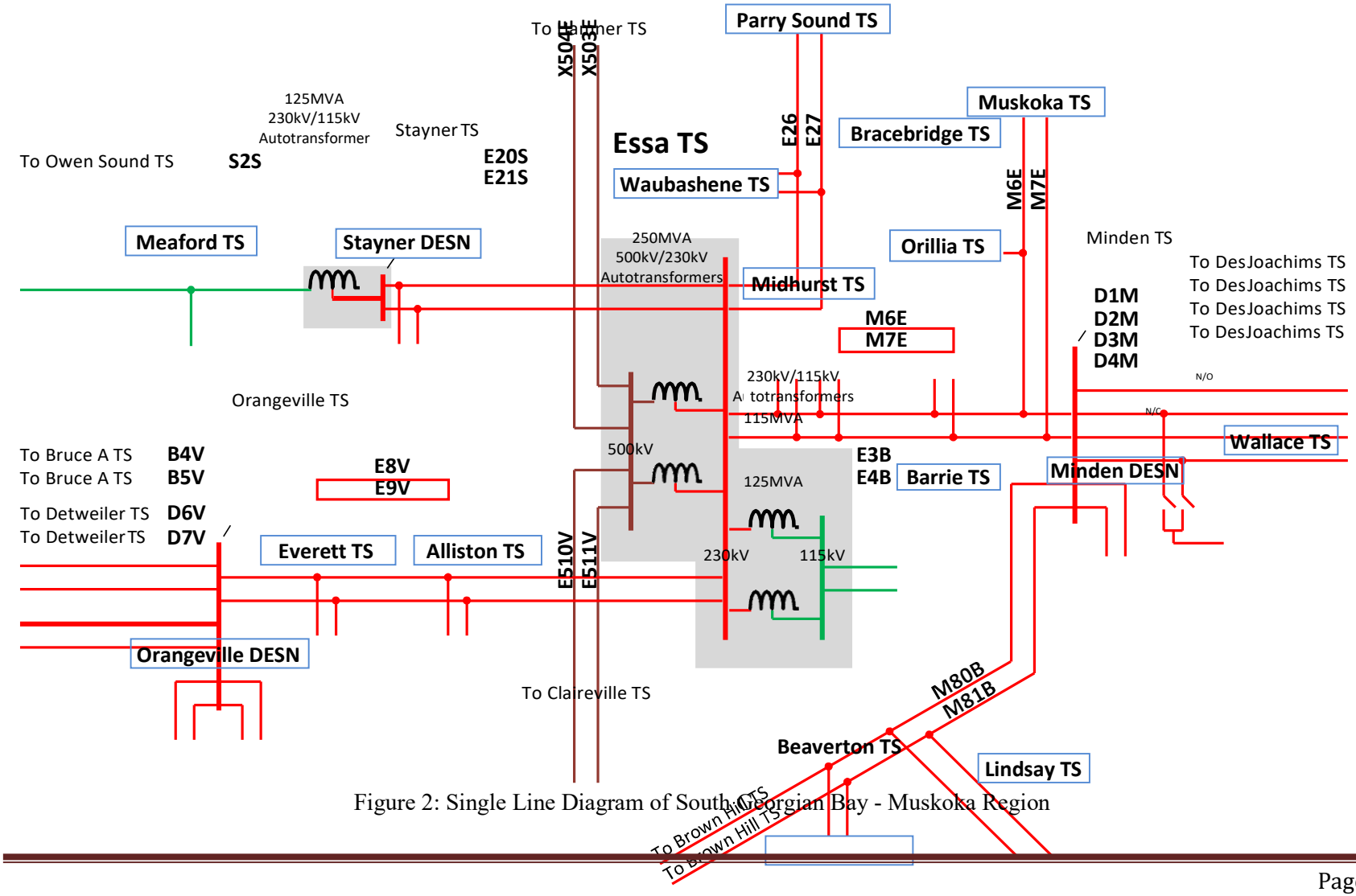


Figure 2: Single Line Diagram of South Georgian Bay - Muskoka Region

6 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the South Georgian Bay - Muskoka Region NA. The information provided includes the following:

- South Georgian Bay - Muskoka Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the SGB-Muskoka Region.

7 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the SGB-Muskoka region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the SGB-Muskoka region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2019 summer and winter peak weather corrected loads. The summer / winter weather correction factors were provided by Hydro One. The net weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the mid-term (5 to 10 year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and an increase in net demand. These load forecasts for the individual stations in the SGB-Muskoka region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of life.

8 NEEDS

This section describes emerging needs identified in the South Georgian Bay - Muskoka Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle.

The status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Needs identified in the previous RP cycle	Needs Details	Current Status	In-Service
Supply Capacity & End-Of Life	Barrie TS transformer supply capacity will be exceeded and has consequently overload the supply circuits (E3B/E4B) InnPower is an embedded LDC supplied from a single 44kV feeder from Barrie TS and requires an additional feeder to supply its loads.	Hydro One's Barrie Area Transmission Reinforcement (BATU) project is underway This investment will address the needs identified in the last RP cycle.	2022
	Parry Sound TS supply capacity has been exceeded, and in need of upgrading. Transformers have also been assessed at being end of life and in need of replacement due to asset condition.	Hydro One will be installing new 230/44kV 83MVA transformers to address both end of life and supply capacity needs.	2024
Load Restoration	Loss of M6E and M7E will result in violation of ORTAC load restoration criteria based on the peak load	Hydro One is installing 230kV motorized disconnect switches on the M6E and M7E circuits. This will improve load restoration time. Underway	2021
End of Life Asset Replacement	Minden TS – Replacement of 230/44kV (T1/T2) transformers	Underway	2021
	Orangeville – Replacement of 230/44/27.6 (T1/T2) and 230/44 (T3/T4) transformers, low voltage switchyard	Underway	2023

8.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
- Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
- Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all of the load to other existing facilities;

In addition, from Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Accordingly, following major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity.

a. Barrie TS – Replace and Upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV.

b. Minden TS -Replace and upgrade existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units.

c. Orangeville TS - Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing non standard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN.

d. Parry Sound TS – Replace and upgrade existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units.

e. M6E/M7E – Refurbish 25km of 230kV transmission line from Orillia TS x Coopers Fls JCT (In-Service 2024)

f. E8V / E9V – Refurbish 56km of 230kV transmission line from Orangeville TS x Essa JCT * (In-Service 2027)

g. D1M / D2M – Refurbish 62km of 230kV transmission line from Minden TS x Otter Creek JCT * (In-Service 2028)

*- further conductor samples/testing to be performed to confirm need.

8.2 Station and Transmission Capacity Needs in the South Georgian Bay - Muskoka Region

The following Station and Transmission supply capacities needs have been identified in the SGB-Muskoka region during the study period of 2020 to 2029.

8.2.1 230/115 kV, & 500/230kV Autotransformers

230/115 kV autotransformers at Essa TS(T1/T2) and Stayner TS (T1) remain within limits for the study period based on both and summer and winter demand forecast. Note: The existing Barrie area transmission upgrade project (BATU) will remove the Essa TS (T1/T2) autotransformers as part of its scope of work in 2022.

500/230kV autotransformers at Essa TS (T3/T4) remain within limits for the study period based on both and summer and winter demand forecast.

8.2.2 230 kV Transmission Lines

The 230kV M6E/M7E circuits from Essa TS to Midhurst TS exceed the Long-Term Emergency (LTE) rating within the study period. With four out of eight Des Joachims GS units are out of service (approx. 200MW) the subsequent loss of either M6E or M7E will result in the companion circuit to exceed its LTE rating. This overload occurs as early as 2023 and continues until the end of the NA study period.

8.2.3 115kV Transmission Lines

With the loss of E4B, the companion E3B circuit will exceed its summer Long-Term Emergency (LTE) rating within the study period. The scope of the Barrie Area Transmission Upgrade (BATU) project will address this finding with an expected 2022 in-service date.

8.2.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs in the Region using both summer and winter station peak load forecasts provided by the study team. The results are as follows:

a. Waubaushene TS

Waubaushene TS has a summer 10-day LTR of 94MW and will exceed its normal supply capacity at the end of 2020 based on the summer demand forecast. Summer overloading at this station has been increasing becoming a concern and the forecast in this NA further reinforces the need for an immediate solution.[1] Initial distribution studies have shown that up to 10MW of load can be permanently transferred to Midhurst TS. This solution in combination with additional CDM/DG initiates may provide the capacity relief needed and its effectiveness will be confirmed in the next stage. While these initiatives are being explored, it is important to note that the existing 230/44kV transformers (T5/T6) are scheduled for replacement in 2030, and if needed can be upgraded to larger units to permanently alleviate supply capacity constraints. This investment can be advanced with agreement from connected LDCs if it needs to be coordinated with shorter term solutions.

b. Everett TS

Everett TS has a summer and winter 10-Day LTR of 86MW. The station supply capability is limited by a CT ratio setting on the low voltage bushing of the transformer breakers, thereby restricting the ability to utilize the full supply capability of the transformers. This restriction can be alleviated by adjusting the CT ratio of the transformer breakers, and must be completed by 2026 to allow station load to continue growing.

c. Barrie TS

Barrie TS presently has a 10-Day LTR of 109MW which will exceed its normal supply capacity in the year 2024 based on the summer demand forecast. The Barrie Area Transmission Project (BATU) project currently underway and once completed will see two new 230/44kV 125MVA transformers increasing the supply capacity of the station (170MVA in the summer), even with the new units installed, station LTR will exceed in the summer 2029. Although capacity does appear to be available for the near and mid-term, Hydro One distribution and its' embedded LDC (InnPower) will see a supply capacity constraint at the 44kV feeder level in 2025. Minor capacity increases can be accommodated on the 44kV system but only on an emergency basis, and can not be used as a permanent supply solution for increased load growth.

[1] Waubaushene TS experienced station loading in excess of 100MVA in July 2018. Although this load occurred for 2hrs and both T5/T6 were in-service, Hydro One operations were ready to initiate control actions to shed load in the event of a transformer outage.

The working group agreed that for this station, it would be reasonable to use the explicit MW values provided by the LDCs, to coincide with ongoing regulatory proceeding related to the aforementioned BATU project. [2] As such, the load forecast for each connected LDC (Shown in Appendix A) at Barrie TS is explicitly shown to provide the working group greater transparency and help to identify individual LDC needs within the study period. A near term solution is required to address this need from InnPower and should be incorporated with any long-term solutions to supply their study forecast of 93MW. InnPower will need new supply capacity into the Innisfil service territory to be provided by 2025 to service its load growth. This growth is consistent with the forecasted growth identified in the 2016 Barrie/Innisfil IRRP.

d. Parry Sound TS

Parry Sound TS has a 10-day winter LTR of 51MW and will be exceeded at the end of 2020 based on the winter demand forecast.
Parry Sound TS presently has 230/44kV 42MVA transformers (T1/T2) that have approached end of life. Hydro One will be right sizing these transformers and replacing these with two new 230/44kV 83MVA units which will provide the supply capacity needed for future load growth. These transformers are scheduled to be in-service 2024. Based on the immediate need for capacity relief at the station, Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers.

e. Other TSs in the Region

All the other transmission stations (TS) in the region are forecasted to remain within their normal supply capacity during the study period. Capacity needs for these stations will be reviewed in the next planning cycle.

8.3 System Reliability, Operation and Restoration Review

No new significant system reliability and operating issues identified for this Region. Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

[2] The forecast provided in IR response (January 9, 2020) with respect to BATU Leave to construct application (EB-2018-0017) illustrates Alectra's assigned capacity of 90MW at Barrie TS.

9 CONCLUSION AND RECOMMENDATIONS

The Study Team recommends the following –

i. Waubaushene TS – Hydro One will coordinate with the connected LDC and their embedded customers (as needed) to address the immediate supply capacity constraints that may appear within the next year. Permanent solution(s) will require further regional coordination to verify if non-wires options would be beneficial. Further regional coordination is required.

ii. Everett TS – Full utilization of the station transformer capacity is restricted by a series limiting component. A CT ratio on the low voltage bushing of the transformer breaker can be changedto allow full transformer LTR capability.
Hydro One will initiate a project directly in collaboration with the LDCs as soon as practical. Further regional coordination is not required.

iii. Barrie TS – The Barrie Area Transmission Upgrade (BATU) project is presently underway with a planned in service of 2022. No further coordination is required for the BATU project.

The working group will continue to develop supply capacity solution(s) for Innisfil area load growth. Further regional coordination is required.

iv. Parry Sound TS – The station transformer upgrade is presently underway and scheduled to be in service in 2024. Hydro One will try to expedite the replacement as quickly as possible and manage overloading risk to the existing transformers. No further regional coordination is required.

v. M6E/M7E (Essa x Midhurst) Overloading – Further regional coordination is required.

vi. Replacement of end of life assets (section 8.1 e.f.g) require further regional coordination.

Appendix A: Weather Adjusted Non-Coincident Summer Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LV Cap bank	LTR (MW)	Customer Data (MW)	Summer Peak Load											
						Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)			
						2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Alliston TS	T2	83	N	75	Gross Peak Load				44.0	44.3	44.6	44.9	45.2	45.5	45.9	46.2	46.5	46.8
					CDM (MW)				0.4	0.5	0.6	0.8	1.0	1.2	1.3	1.6	1.8	1.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	41.0	38.5	43.7	43.6	43.8	44.0	44.1	44.2	44.4	44.5	44.5	44.7	45.0
Alliston TS	T3/T4	111	N	100	Gross Peak Load				71.1	73.2	75.4	77.7	80.1	82.5	85.0	87.5	90.2	92.9
					CDM (MW)				0.6	0.8	1.0	1.4	1.7	2.1	2.4	3.1	3.4	3.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	76.7	61.8	69.0	70.5	72.5	74.4	76.3	78.3	80.3	82.5	84.4	86.8	89.2
Barrie TS	T1/T2	115	Y	109	Gross Peak (Alectra)				65.1	67.1	69.2	71.3	73.5	75.5	77.4	79.4	81.5	83.6
					Gross Peak (InnPower)				19.0	23.2	30.1	39.8	48.8	56.8	65.4	75.6	84.3	92.9
					Gross Peak (Total)				84.1	90.3	99.3	111.2	122.3	132.2	142.8	155.0	165.8	176.5
					CDM (MW)				0.7	0.9	1.4	2.0	2.7	3.4	4.1	5.5	6.3	7.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	93.9	119.5	127.9	83.4	89.4	97.9	109.1	119.7	128.8	138.8	149.5	159.5	169.5
Beaverton TS	T3/T4	203	Y	193	Gross Peak Load				60.2	60.8	61.3	61.9	62.4	63.0	63.5	64.1	64.7	65.3
					CDM (MW)				0.5	0.6	0.8	1.1	1.4	1.6	1.8	2.3	2.4	2.6
					DG (MW)				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					Net Load Forecast	52.9	55.7	59.7	59.5	59.9	60.3	60.5	60.9	61.2	61.5	61.7	62.0	62.5
Bracebridge TS	T1	83	N	75	Gross Peak Load				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
					CDM (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	13.0	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Everett TS	T1/T2	95	N	86	Gross Peak Load				74.6	76.8	79.0	81.3	83.7	86.2	88.7	91.3	94.0	96.8
					CDM (MW)				0.6	0.8	1.1	1.5	1.8	2.2	2.5	3.2	3.6	3.8
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	82.0	70.9	72.5	73.9	76.0	77.9	79.9	81.9	84.0	86.2	88.1	90.4	92.9
Lindsay TS	T1/T2	169	Y	161	Gross Peak Load				79.9	80.9	82.0	83.0	84.1	85.2	86.3	87.4	88.5	89.7
					CDM (MW)				0.7	0.8	1.1	1.5	1.8	2.2	2.5	3.1	3.3	3.5
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	72.3	72.9	78.9	79.1	80.0	80.7	81.4	82.2	82.9	83.7	84.2	85.1	86.0
Meaford TS	T1/T2	55	Y	52	Gross Peak Load				26.8	27.0	27.1	27.3	27.5	27.7	27.8	28.0	28.2	28.4
					CDM (MW)				0.2	0.3	0.4	0.5	0.6	0.7	0.8	1.0	1.1	1.1
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	30.2	33.4	26.6	26.6	26.7	26.8	26.8	26.9	27.0	27.0	27.0	27.1	27.2
Midhurst TS	T1/T2	171	Y	162	Gross Peak Load				120.6	122.9	125.3	127.7	130.2	132.7	135.3	137.9	140.6	143.3
					CDM (MW)				1.0	1.3	1.7	2.3	2.8	3.4	3.9	4.9	5.3	5.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	122.0	122.5	118.3	119.5	121.6	123.6	125.4	127.4	129.3	131.4	133.1	135.3	137.6
Midhurst TS	T3/T4	166	N	149	Gross Peak Load				99.7	102.5	105.4	108.4	111.4	114.6	117.8	121.1	124.6	128.1
					CDM (MW)				0.9	1.1	1.4	2.0	2.4	2.9	3.4	4.3	4.7	5.1
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	110.1	97.2	97.0	98.8	101.5	104.0	106.4	109.0	111.6	114.5	116.9	119.9	123.0
Minden TS	T1/T2	58	N	52	Gross Peak Load				42.9	43.2	43.5	43.9	44.2	44.5	44.8	45.1	45.4	45.8
					CDM (MW)				0.4	0.4	0.6	0.8	1.0	1.1	1.3	1.6	1.7	1.8
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	39.9	39.5	42.6	42.6	42.8	42.9	43.1	43.2	43.3	43.5	43.5	43.7	44.0
Muskoka TS	T1/T2	178	Y	169	Gross Peak Load				131.0	133.1	135.1	137.2	139.4	141.6	143.8	146.0	148.3	150.6
					CDM (MW)				1.1	1.4	1.9	2.5	3.0	3.6	4.1	5.1	5.6	6.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	-1.0	-1.2	-1.2
					Net Load Forecast	118.8	132.7	129.0	129.8	131.6	133.2	134.6	136.2	137.8	139.5	141.9	143.8	145.8

Orangeville TS	T1/T2	103	N	93	Gross Peak Load				58.2	58.8	59.5	60.2	60.8	61.5	62.2	62.9	63.6	64.3
					CDM (MW)				0.5	0.6	0.8	1.1	1.3	1.6	1.8	2.2	2.4	2.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2
					Net Load Forecast	50.7	52.7	57.5	57.7	58.2	58.7	59.1	59.5	59.9	60.4	60.9	61.4	62.0
Orangeville TS	T3/T4	106	Y	101	Gross Peak Load				75.4	76.3	77.1	78.0	78.9	79.7	80.6	81.5	82.4	83.4
					CDM (MW)				0.7	0.8	1.1	1.4	1.7	2.1	2.3	2.9	3.1	3.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2
					Net Load Forecast	70.2	69.9	74.6	74.8	75.5	76.1	76.6	77.1	77.7	78.3	78.8	79.5	80.2
Orillia TS	T1/T2	162	Y	154	Gross Peak Load				116.7	118.3	119.9	121.5	123.2	124.9	126.6	128.4	130.1	131.9
					CDM (MW)				1.0	1.2	1.6	2.2	2.7	3.2	3.6	4.5	4.9	5.2
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	96.1	107.4	115.1	115.7	117.1	118.3	119.3	120.5	121.7	123.0	123.9	125.2	126.7
Parry Sound TS	T1/T2	52	N	47	Gross Peak Load				45.1	45.5	45.9	46.3	46.8	47.2	47.6	48.0	48.4	48.8
					CDM (MW)				0.4	0.5	0.6	0.8	1.0	1.2	1.4	1.7	1.8	1.9
					DG (MW)				0.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	-0.2	-0.2
					Net Load Forecast	41.0	42.5	44.8	44.8	43.6	43.9	44.1	44.3	44.5	44.8	44.9	46.7	47.1
Stayner TS	T3/T4	191	Y	181	Gross Peak Load				119.5	120.7	122.0	123.2	124.5	125.8	127.0	128.3	129.7	131.0
					CDM (MW)				1.0	1.2	1.7	2.3	2.7	3.2	3.6	4.5	4.9	5.2
					DG (MW)				0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	108.0	112.4	118.3	118.5	119.4	120.2	120.8	121.6	122.4	123.3	123.7	124.6	125.7
Wallace TS	T3/T4	54	N	49	Gross Peak Load				39.8	40.1	40.4	40.8	41.1	41.5	41.8	42.2	42.5	42.9
					CDM (MW)				0.3	0.4	0.6	0.7	0.9	1.1	1.2	1.5	1.6	1.7
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	27.0	37.5	39.4	39.4	39.7	39.9	40.0	40.2	40.4	40.6	40.7	40.9	41.2
Waubaushene TS	T5/T6	99	Y	94	Gross Peak Load				99.0	100.0	100.9	101.9	102.9	103.9	104.9	105.9	107.0	108.0
					CDM (MW)				0.9	1.0	1.4	1.9	2.2	2.7	3.0	3.7	4.0	4.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	85.3	92.2	98.0	98.1	98.9	99.5	100.0	100.7	101.2	101.9	102.2	102.9	103.8

Appendix A: Weather Adjusted Non-Coincident Winter Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LV Cap bank	LTR (MW)	Customer Data (MW)	Winter Peak Load											
						Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)			
						2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Alliston TS	T2	83	N	75	Gross Peak Load				31.3	31.5	31.7	31.9	32.1	32.3	32.5	32.7	32.9	33.1
					CDM (MW)				0.2	0.2	0.2	0.3	0.4	0.5	0.5	0.5	0.5	0.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	35.9	36.2	31.1	31.1	31.3	31.5	31.6	31.7	31.8	32.0	32.2	32.3	32.5
Alliston TS	T3/T4	128	N	115	Gross Peak Load				73.7	75.9	78.2	80.6	83.0	85.5	88.1	90.8	93.5	96.4
					CDM (MW)				0.4	0.4	0.6	0.8	1.0	1.2	1.4	1.4	1.5	1.5
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	57.0	57.3	71.6	73.3	75.5	77.7	79.8	82.0	84.3	86.8	89.4	92.1	94.8
Barrie TS	T1/T2	127	Y	121	Gross Peak (Alectra)				54.7	56.4	58.2	60.0	61.8	63.4	65.1	66.8	68.5	70.3
					Gross Peak (InnPower)				19.0	23.2	30.1	39.8	48.8	56.8	65.4	75.6	84.3	92.9
					Gross Peak (Total)				73.7	79.6	88.2	99.8	110.6	120.2	130.5	142.3	152.8	163.2
					CDM (MW)				0.4	0.5	0.6	1.0	1.3	1.7	2.0	2.3	2.4	2.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	95.1	78.4	80.9	73.3	79.2	87.6	98.8	109.3	118.5	128.5	140.1	150.4	160.6
Beaverton TS	T3/T4	224	Y	213	Gross Peak Load				83.7	84.4	85.1	85.8	86.5	87.2	87.9	88.7	89.4	90.2
					CDM (MW)				0.5	0.5	0.6	0.8	1.0	1.2	1.4	1.4	1.4	1.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	79.2	78.4	83.0	83.2	83.9	84.5	84.9	85.5	86.0	86.6	87.3	88.0	88.7
Bracebridge TS	T1	83	N	75	Gross Peak Load				0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
					CDM (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	0.2	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Everett TS	T1/T2	95	N	86	Gross Peak Load				81.6	82.2	82.9	83.6	84.3	85.0	85.7	86.4	87.1	87.9
					CDM (MW)				0.5	0.5	0.6	0.8	1.0	1.2	1.3	1.4	1.4	1.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	78.2	76.4	80.9	81.1	81.8	82.3	82.8	83.3	83.8	84.4	85.0	85.7	86.5
Lindsay TS	T1/T2	192	Y	182	Gross Peak Load				95.5	96.7	97.9	99.1	100.3	101.5	102.8	104.0	105.3	106.6
					CDM (MW)				0.5	0.6	0.7	1.0	1.2	1.4	1.6	1.6	1.7	1.7
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
					Net Load Forecast	88.7	91.5	94.4	94.9	96.0	97.1	98.0	99.0	100.0	101.1	102.3	103.6	104.8
Meaford TS	T1/T2	62	Y	59	Gross Peak Load				34.4	34.7	34.9	35.1	35.4	35.6	35.8	36.1	36.3	36.5
					CDM (MW)				0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.6	0.6	0.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	33.8	30.2	34.2	34.2	34.5	34.7	34.8	34.9	35.1	35.3	35.5	35.7	36.0
Midhurst TS	T1/T2	193	Y	183	Gross Peak Load				98.8	101.8	105.0	108.2	111.6	114.5	117.5	120.5	123.6	126.9
					CDM (MW)				0.6	0.6	0.7	1.1	1.3	1.6	1.8	1.9	2.0	2.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	103.5	100.5	100.6	98.2	101.2	104.2	107.2	110.3	112.9	115.6	118.6	121.7	124.9
Midhurst TS	T3/T4	191	N	172	Gross Peak Load				119.4	122.8	126.3	129.8	133.5	137.3	141.1	145.1	149.2	153.4
					CDM (MW)				0.7	0.7	0.9	1.3	1.6	1.9	2.2	2.3	2.4	2.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	123.6	91.5	116.1	118.7	122.1	125.4	128.5	131.9	135.3	138.9	142.8	146.9	151.0
Minden TS	T1/T2	64	N	58	Gross Peak Load				55.3	55.7	56.0	56.4	56.8	57.1	57.5	57.9	58.3	58.6
					CDM (MW)				0.3	0.3	0.4	0.6	0.7	0.8	0.9	0.9	0.9	0.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	57.0	53.3	55.0	55.0	55.4	55.6	55.8	56.1	56.3	56.6	57.0	57.3	57.7
Muskoka TS	T1/T2	209	Y	199	Gross Peak Load				164.3	166.8	169.4	172.1	174.7	177.4	180.2	183.0	185.8	188.7
					CDM (MW)				0.9	1.0	1.2	1.7	2.1	2.5	2.8	2.9	2.9	3.0
					DG (MW)				0.1	0.1	0.1	0.1	0.1	0.1	0.1	-1.2	-1.3	-1.3
					Net Load Forecast	163.7	157.8	161.8	163.2	165.7	168.1	170.2	172.5	174.8	177.2	181.2	184.2	187.0

Orangeville TS	T1/T2	121	N	109	Gross Peak Load				50.3	50.8	51.4	51.9	52.5	53.0	53.6	54.1	54.7	55.3
					CDM (MW)				0.3	0.3	0.4	0.5	0.6	0.7	0.8	0.9	0.9	0.9
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.5	-1.5	-1.5
					Net Load Forecast	49.6	47.2	49.8	50.0	50.5	51.0	51.4	51.8	52.3	52.7	54.8	55.3	55.9
Orangeville TS	T3/T4	123	Y	117	Gross Peak Load				89.1	90.0	91.0	91.9	92.9	93.9	94.8	95.8	96.9	97.9
					CDM (MW)				0.5	0.5	0.6	0.9	1.1	1.3	1.5	1.5	1.5	1.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.4	-1.4	-1.4
					Net Load Forecast	76.1	83.4	88.1	88.6	89.5	90.3	91.0	91.8	92.5	93.4	95.8	96.8	97.8
Orillia TS	T1/T2	184	Y	175	Gross Peak Load				127.2	128.9	130.6	132.4	134.1	135.9	137.8	139.6	141.5	143.4
					CDM (MW)				0.7	0.8	0.9	1.3	1.6	1.9	2.2	2.2	2.2	2.3
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	119.4	118.6	125.5	126.4	128.1	129.7	131.0	132.5	134.0	135.6	137.4	139.3	141.1
Parry Sound TS	T1/T2	57	N	51	Gross Peak Load				56.5	56.9	57.4	57.9	58.4	58.9	59.4	59.9	60.4	60.9
					CDM (MW)				0.3	0.3	0.4	0.6	0.7	0.8	0.9	0.9	1.0	1.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.8	-1.8
					Net Load Forecast	57.0	53.3	56.0	56.1	56.6	57.0	57.3	57.7	58.0	58.4	58.9	61.2	61.7
Stayner TS	T3/T4	213	Y	202	Gross Peak Load				140.0	141.1	142.1	143.2	144.3	145.3	146.4	147.5	148.7	149.8
					CDM (MW)				0.8	0.8	1.0	1.4	1.7	2.1	2.3	2.3	2.4	2.4
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	138.4	132.7	139.0	139.2	140.2	141.1	141.8	142.5	143.3	144.2	145.2	146.3	147.4
Wallace TS	T3/T4	60	N	54	Gross Peak Load				37.4	37.5	37.6	37.7	37.8	37.9	38.0	38.1	38.2	38.3
					CDM (MW)				0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	38.0	35.2	37.3	37.2	37.3	37.3	37.3	37.3	37.4	37.4	37.5	37.6	37.7
Waubaushene TS	T5/T6	109	Y	104	Gross Peak Load				95.2	96.1	97.0	97.9	98.7	99.6	100.5	101.5	102.4	103.3
					CDM (MW)				0.5	0.6	0.7	1.0	1.2	1.4	1.6	1.6	1.6	1.6
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	94.0	90.5	94.4	94.7	95.5	96.3	96.9	97.6	98.2	99.0	99.9	100.8	101.7

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)
1.	Alliston TS	230/44
2.	Barrie TS	115/44
3.	Beaverton TS	230/44
4.	Bracebridge TS	230/44
5.	Essa TS	500/230/115
6.	Everett TS	230/44
7.	Lindsay TS	230/44
8.	Meaford TS	230/44
9.	Midhurst TS	230/44
10.	Minden TS	230/44
11.	Muskoka TS	230/44
12.	Orangeville TS	230/44/27.6
13.	Orillia TS	230/44
14.	Parry Sound TS	230/44
15.	Stayner TS	230/115/44
16.	Wallace TS	230/44
17.	Waubashene TS	230/44

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	E20/E21S	Essa TS	Stayner TS	230
2.	E26/E27	Essa TS	Parry Sound TS	230
3.	M6E/M7E	Essa TS	Minden TS	230
4.	D1M/D2M	Minden TS	Des Joachims TS	230
5.	D3M/D4M	Minden TS	Des Joachims TS	230
6.	M80B/M81B	Minden TS	Brown Hill TS	230
7.	E3B/E4B	Essa TS	Barrie TS	115
8.	S2S	Stayner TS	Owen Sound TS	115

Appendix D: Lists of LDCs in the SGB-Muskoka Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Networks Inc. (Distribution)	TX
2.	Alectra Utilities	TX/DX
3.	InnPower	DX
4.	Orangeville Hydro	DX
5	Elexicon Energy	DX
6.	Lakeland Power	DX
7.	EPCOR Electricity Dist. Ontario Inc.	DX
8.	Newmarket-Tay Power Distribution Ltd	DX
9.	Orillia Power Distribution Corp.	DX
10.	Wasaga Distribution Inc.	DX

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station



Appendix D

Scoping Assessment Outcome Report



South Georgian Bay/Muskoka Scoping Assessment Outcome Report

November 30, 2020

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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the regional planning process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first cycle of the regional planning process for the South Georgian Bay/Muskoka region was completed in August 2017 with the publishing of the Regional Infrastructure Plan (RIP)[1]. A number of needs were identified to arise in the near- and medium-term timeframes. Prior to the completion of the RIP, two Integrated Regional Resource Plans (IRRPs) were produced in December 2016, as the South Georgian Bay/Muskoka area needs were scoped into two sub-regions for further study: the summer-peaking, high-growth Barrie/Innisfil[2] sub-region, and the winter-peaking, slower-growing Parry Sound/Muskoka[3] sub-region.

The IRRPs outlined recommendations to address all near-term needs, and identified mid- to long-term needs to be confirmed in the next planning cycle. Both IRRPs also identified near-term actions to be carried out in advance of the next cycle of regional planning to gather information to better identify options for future needs. This included the completion of Local Achievable Potential Studies (LAPS) for a portion of each sub-region, to help determine the availability and cost of potential non-wires solutions.

The new cycle of the regional planning process for the South Georgian Bay/Muskoka region started on January 30, 2020. The Needs Assessment is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. (Hydro One). This report was finalized on April 30, 2020, and recommended that a number of needs require regional coordination. This need information was an input into the Scoping Assessment to determine the nature of the planning process required.

During the Scoping Assessment, the Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. This process also determined the best geographic grouping of the needs to efficiently carry out the study. It also considered past or ongoing initiatives in the region, such as the findings of the two LAPS triggered in the last planning cycle. These studies, which assessed the cost and feasibility of using distributed energy resources and local demand management options, will inform and support the analysis of non-wires alternatives in the current cycle.

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[1] 2017 RIP: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/southgeorgianbaymuskoka/Documents/South_Georgian_Bay-Muskoka_RIP_Final.pdf

[2] 2016 IRRP for the Barrie/Innisfil Sub-region: http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Barrie-Innisfil/Barrie-Innisfil-IRRP.pdf?la=en

[3] 2016 IRRP for the Parry Sound/Muskoka Sub-region: http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Parry-Sound-Muskoka/PSM-IRRP.pdf?la=en

The Scoping Assessment considers three potential planning approaches for the region/sub-regions, including: an IRRP – where both wires and non-wires options have potential to address needs; a RIP – which considers wires-only options; or a local plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs;
- Determines the appropriate regional planning approach and scope for each sub-region where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP if an IRRP is required; and
- Establishes the composition of the Technical Working Group for each sub-region recommended for an IRRP.

2. Study Team

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Hydro One Transmission)
- Hydro One Networks Inc. (Hydro One Distribution)
- Alectra Utilities
- InnPower Corporation
- Orangeville Hydro
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

3. Categories of Needs, Analysis, and Results

3.1 Overview of the Region

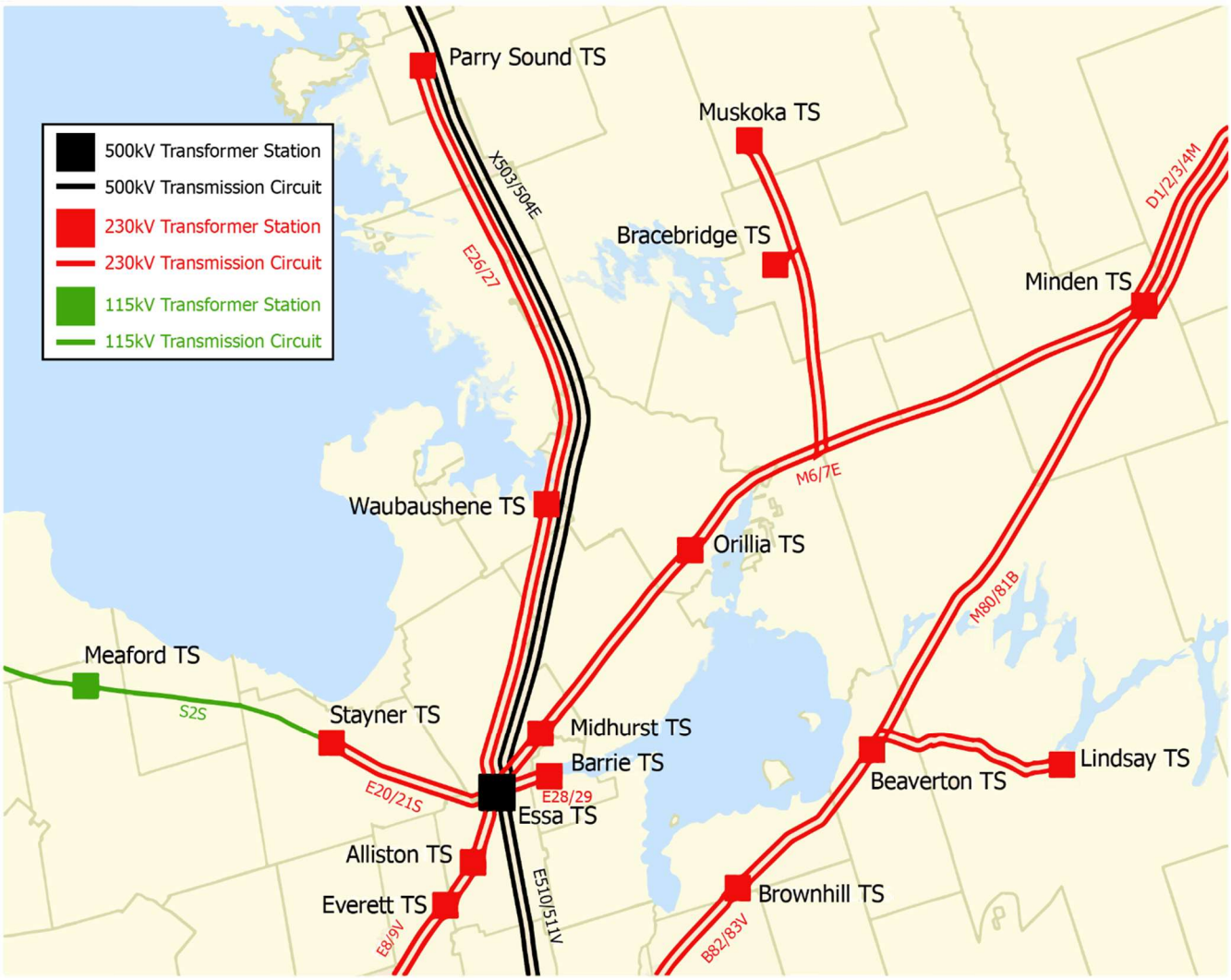
The South Georgian Bay/Muskoka region is located in central Ontario and includes all or part of the following Counties and Districts: the County of Simcoe, County of Dufferin, District of Muskoka, District of Parry Sound, and County of Grey. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

This region also includes the following First Nations and Métis Nation of Ontario (MNO) councils:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama
- Chippewas of Georgina Island
- Mississaugas of Scugog
- MNO Barrie South Simcoe Métis Council
- MNO Moon River Métis Council
- MNO Georgian Bay Métis Council

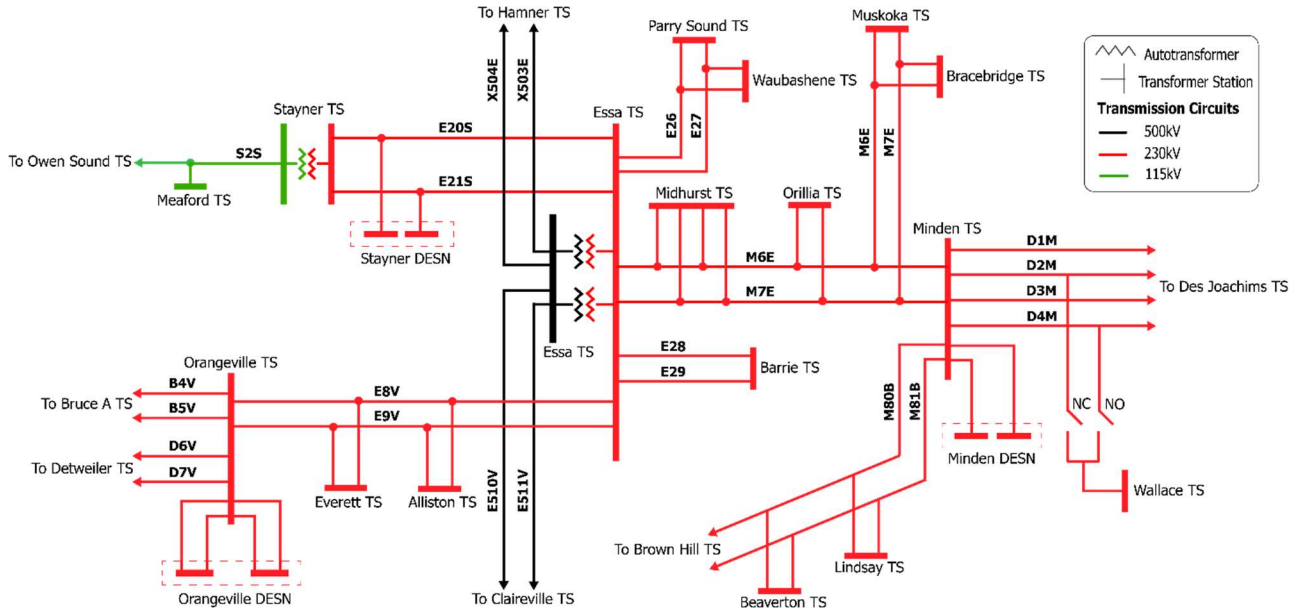
An overview of the South Georgian Bay/Muskoka region and the location of the electrical infrastructure is shown in Figure 3-1. The southern portion of this region is summer-peaking (i.e., electricity demand is highest during the summer months), and is characterized by strong forecast growth, particularly in the south Barrie and Innisfil areas. The northern part of the region is winter-peaking (i.e., electricity demand is highest during the winter months), and growth is forecast to be more gradual.

Figure 3-1 | Overview of the South Georgian Bay/Muskoka Region



The region is currently supplied from 115 kV and 230 kV transmission lines and stations that connect at the Essa transformer station (TS). The 500/230 kV auto-transformers at Essa TS provide the major source of supply to the area. As an outcome of the last planning cycle, the 115 kV supply in the region (from Essa TS to Barrie TS) is being converted to a 230 kV supply in 2022. An overview of the electrical infrastructure that currently supplies the region is provided in the single line diagram in Figure 3-2.

Figure 3-2 | Electricity Infrastructure in the South Georgian Bay/Muskoka Region



3.2 Background of the Previous Planning Process

The regional planning process was formalized by the OEB in August 2013. To prioritize and manage the process, Ontario was organized into 21 regions based on electricity infrastructure boundaries; each of which were assigned to one of three groups based on urgency of need, where Group 1 Regions were being reviewed first. The South Georgian Bay/Muskoka region was part of the Group 2 planning regions.

In March 2015, Hydro One Transmission published the first Needs Assessment report for the South Georgian Bay/Muskoka region. The scope of the report included a review of system capability, reliability assessments, and asset sustainment timelines for the region. The report identified a number of near- and mid-term needs. In June of 2015, the IESO published a Scoping Assessment report for the region, recommending that two IRRPs would be developed to address the identified needs: one for the Barrie/Innisfil sub-region and one for the Parry Sound/Muskoka sub-region.

Within the Terms of Reference for the IRRP for the Barrie/Innisfil sub-region, a need to proceed quickly to address near-term needs at Barrie TS was identified. While the IRRP was still underway in December 2015, the IESO provided a hand-off letter to Hydro One in support of commencing work on uprating Barrie TS to a 230 kV supply to meet the capacity and end-of-life needs identified in south Barrie and Innisfil.

Subsequently in December of 2016, the first IRRP reports for the two South Georgian Bay/Muskoka sub-regions were published. Both IRRPs used a 20-year outlook, allowing the long-term trends in the region to be considered while implementing near-term actions. To address near- and mid-term needs in the first 10 years of the forecast, a number of recommendations were made. Section 3.3.1

documents the status of the near-term transmission reinforcements that were recommended during the first cycle of regional planning for South Georgian Bay/Muskoka.

In addition to the above recommendations, the previous IRRPs also recommended that two LAPS be undertaken in order to better understand the feasibility and cost of potential non-wires alternatives for addressing select mid- and long-term capacity needs. A LAPS was undertaken for the service area of Barrie TS, led by Alectra Utilities and supported by InnPower, and a LAPS was undertaken for the Parry Sound TS and Waubaushene TS service areas, led by Lakeland Power. These studies have now both concluded and will inform the current regional planning cycle.

Following the IRRP, a RIP was published in August 2017 to address transmission needs identified in the Needs Assessment and the IRRP. The plans to address some of these needs were further developed in the RIP. Some of the needs and recommended options that were in the medium- to longer-term time frame were to be re-confirmed in the next regional planning cycle.

This current, second regional planning cycle started with the Needs Assessment report published by Hydro One in April 2020. The needs identified in the Needs Assessment report form the basis of the analysis for this Scoping Assessment and are discussed in further detail in Section 3.3.

3.3 Needs Identified

Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. Furthermore, it identified a number of new needs in the South Georgian Bay/Muskoka region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans Underway

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation. Table 3-1 below summarizes this. These projects provide a basis for future assessments and should be accounted for in this planning cycle.

Table 3-1 | Needs Identified in the Previous Cycle and Implementation Plan Update

IRRP	Specific Need	Solution and Timing
Barrie/Innisfil Sub-Region	• Insufficient capacity at Barrie TS and Barrie/Essa 115 kV system • End-of-life Barrie TS, E3/4B circuits, Essa 230/115 kV autotransformers	• BATU project (rebuild and uprate Barrie TS and E3/4B circuits to 230 kV, and retire Essa T1/T2) • In-service in 2022

IRRP	Specific Need	Solution and Timing
Parry Sound/Muskoka Sub-Region	• Insufficient capacity at Parry Sound TS • End-of-life Parry Sound transformers	• Transformer upsizing (new 230/44 kV 83 MVA) • In-service in 2024
	• Load restoration criteria violations under M6E+M7E contingency	• Installation of 230 kV switches on M6E/M7E at Orillia TS • In-service in 2021
	• End-of-life 230/44 kV 42 MVA Minden TS transformers	• Replacement with larger 83 MVA units to address station capacity needs • In-service in 2021

3.3.2 Needs to be Addressed in Current Planning Cycle

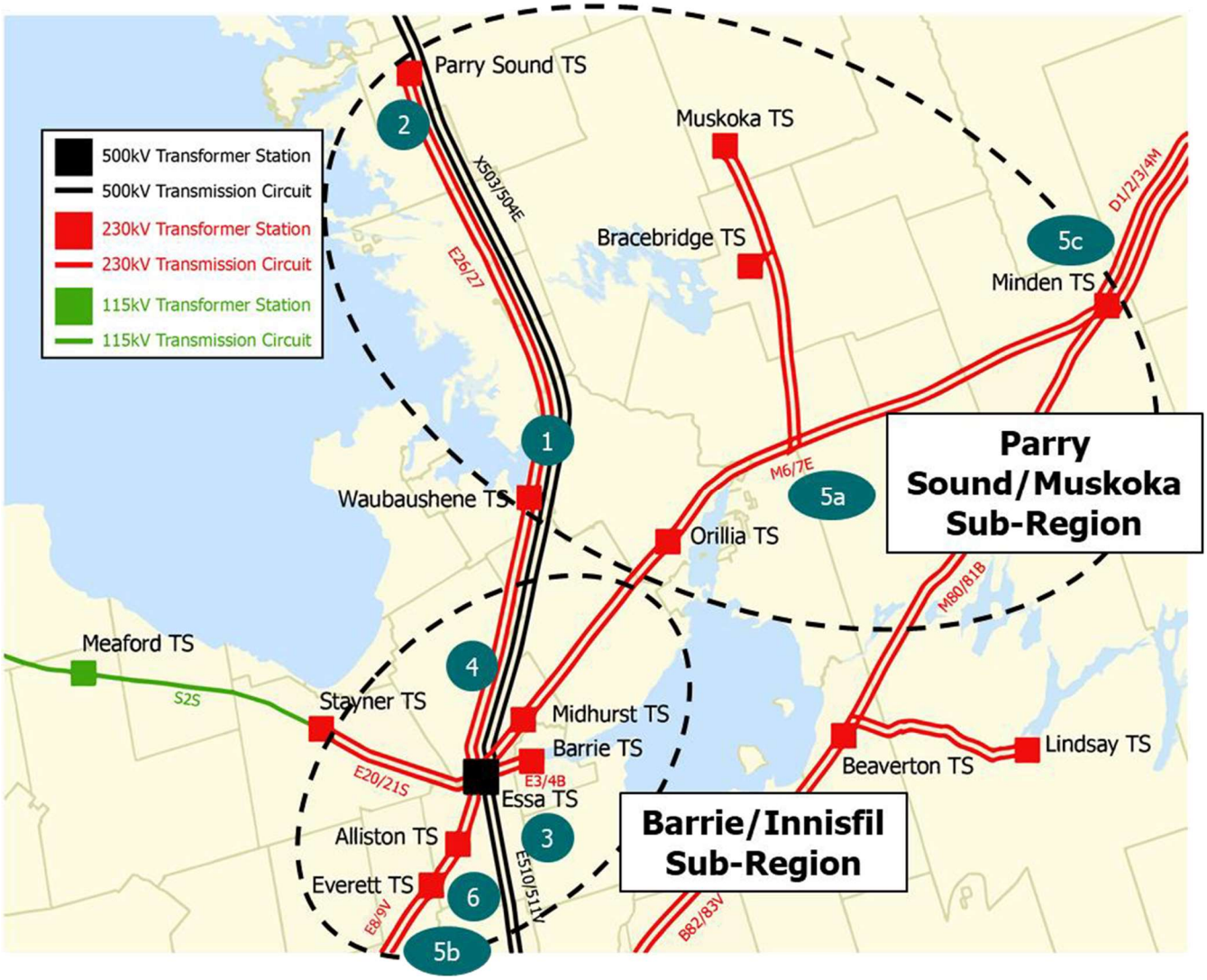
The Needs Assessment then identified new or updated needs in the South Georgian Bay/Muskoka region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated end-of-life asset condition information, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Table 3-2 below lists these regional needs and their timing. Their location is shown in Figure 3-3.

Table 3-2 | Updated Regional Needs Identified in the NA

Need	Station/Circuit	Description of Need
1	Waubaushene TS	• Supply capacity exceeded in 2020
2	Parry Sound TS	• Existing 230/44 kV, 42 MVA transformers reach end-of-life in near-term • Station capacity need between 2020-2024, before larger (230/44 kV, 83 MVA) replacement transformers are in-service
3	Barrie TS/Innisfil Area	• Subsequent to BATU, InnPower has a supply capacity constraint on the 44 kV feeder level starting in 2025 • Up-sized Barrie TS will have a station capacity need arising in 2029

Need	Station/Circuit	Description of Need
4	M6E/M7E	• Thermal overload (exceeding Long-Term Emergency, LTE, rating) between Essa TS x Midhurst TS starting in 2023 (assuming four Des Joachims GS units are out of service)
5	M6E/M7E E8V/E9V D1M/D2M	• Various sections to be refurbished due to end-of-life needs • M6E/M7E: in-service 2026 • E8V/E9V: in-service 2026 • D1M/D2M: in-service 2028
6	Everett TS	• Full utilization of the existing station supply capacity is limited due to a limiting component within the low voltage yard; need arises in 2026 (rather than 2027, as identified in the last IRRP) • CT ratio setting on the low voltage bushing of the transformer breaker can be modified to allow full transformer limited time rating (LTR) capability

Figure 3-3 | Geographic Location of Needs Identified in the Needs Assessment



3.3.3 Analysis of Needs and Identification of Sub-Regions

The Study Team has discussed the needs in the South Georgian Bay/Muskoka region and potential planning approaches to address them. Consistent with the previous planning cycle, two sub-regions, Barrie/Innisfil and Parry Sound/Muskoka, have been identified for further study in the regional planning process (geographic area of the sub-regions is identified in Figure 3-3).

In addition to discussing the planning approach for the identified needs and the division of the sub-regions, the Study Team also discussed the potential impact of the COVID-19 pandemic, as there are supply capacity needs in the region driven by forecast load growth. The Study Team noted that the pandemic may have a temporary and near-term impact on the load growth. However, there is also the potential for certain needs to materialized with greater magnitude (e.g. continued development of housing stock in the south Barrie area). Therefore, the Study Team agreed to assess the needs using the need dates from the Needs Assessments, which was based on the original demand forecast completed prior to the pandemic. Throughout the IRRP process, potential near-term impacts to demand from the COVID-19 pandemic will continue to be monitored.

Barrie/Innisfil Sub-Region

Supplied by Alectra Utilities, InnPower Corporation, and Hydro One Distribution, this sub-region continues to exhibit strong electricity demand growth – particularly in the south Barrie and Innisfil area. The following transmission infrastructure falls within this sub-region's boundaries:

- Transformer stations: Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits: E8/9V, E28/29, M6/7E (Essa-Midhurst section)

Forecast growth is expected to trigger a supply capability need in the south Barrie and Innisfil area after the BATU project is in-service:

1. In the near-term, supply to InnPower's service territory is limited by two 44 kV feeders supplied from Barrie TS, and
2. In the mid-term, the combined load growth in the Barrie area will exceed the station capacity of uprated Barrie TS.

The potential for integrated solutions to address these near- and mid-term capacity needs should be evaluated through an IRRP. Potential wires options may involve a new line, an additional transformer station, a further expansion of Barrie TS, additional feeders, or load transfers. Furthermore, the potential for non-wires alternatives to defer or meet a portion of the sub-region's needs will also be evaluated. Findings from the Barrie TS LAPS recommended from the 2016 IRRP can support and inform this assessment.

In addition to supply capability needs at Barrie TS and in the Innisfil area, network circuits from Essa TS (M6/7E) are expected to be thermally overloaded under certain post-contingency system conditions. Various sections of other nearby circuits (E8/9V, M6/7E, and D1/2M) have also been identified in the Needs Assessment as reaching end-of-life. Needs on these circuits are sensitive to generation output and bulk power system flow assumptions (particularly flows both north and south on the transmission interface (i.e. path) through Essa TS), as well as the region's load level. These types of needs are typically addressed through bulk planning, although coordination is required with the regional planning process to ensure system assumptions are aligned, and potential impacts of solutions from either regional or bulk planning are accounted for in the other plan.

The supply capability need at Everett TS is driven by the current setting of the station equipment, preventing utilization of the full station capacity. As this need has only been advanced by a year and has not otherwise changed since identified in the previous IRRP, the Study Team continues to support the solution recommended in 2016.

Recommendation: The Barrie/Innisfil sub-region has a mixture of urgent, more complex system capacity needs, and mid-term end-of-life and capacity needs. Integrated solutions should be evaluated to meet these regional needs while coordinating with any bulk system assessments. Outcomes of the regional plan are anticipated to have broader impacts and require input from multiple stakeholders (LDCs, transmitter, community members, and municipalities). The Study Team, therefore, proposes that an IRRP is conducted for the Barrie/Innisfil sub-region to identify the most cost-effective and feasible solutions.

For the supply capability need identified on the M6E/M7E circuit, the Study Team recommends that a bulk study be completed and that the results be shared with the Technical Working Group as applicable.

Parry Sound/Muskoka Sub-Region

Supplied by Hydro One Distribution, Lakeland Power, Newmarket-Tay Power, Elexicon Energy, and EPCOR Electricity Distribution Ontario Inc., this winter-peaking sub-region exhibits slower electricity demand growth. The following transmission infrastructure falls within this sub-region's boundaries:

- Transformer stations: Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits: M6/7E, E26/27

According to the Needs Assessment, Waubaushene TS will require additional supply capacity starting 2020, and a total of 10 MW will be required in 2029 when the station is expected to reach end-of-life. The end-of-life need in 2030 provides an opportunity to replace the station transformers with higher rated units, and the 10 MW capacity need prior to 2029 has the potential to be managed by non-wires solutions. In addition, non-wires options have recently been modelled for the Waubaushene area, providing a basis to explore and evaluate any non-wires potential in the area.

During the last cycle of regional planning, re-supplying loads at Waubaushene TS from nearby stations was recommended. According to the 2016 IRRP, 4 MW of load at Waubaushene TS can be supplied by Orillia TS, and another 7 MW from Waubaushene TS can be supplied by Midhurst TS. These options, not yet implemented, will be reassessed in this planning cycle as part of identifying an integrated solution to address the need. This includes coordinating with the impacted LDCs to obtain the appropriate load transfer approvals if required.

Parry Sound TS requires additional supply capacity starting 2020. The transformers at Parry Sound TS have also reached end-of-life and are scheduled to be replaced with higher rated units in 2024. During the previous cycle of the regional plan, this supply capacity need at Parry Sound TS was identified. Transferring 6 MW of load from Parry Sound TS to the nearby Muskoka TS was recommended to manage the loading at Parry Sound TS. This option will be reassessed as part of identifying an integrated solution to address the capacity and end-of-life needs.

Recommendation: There is a need to evaluate integrated solutions to address the sub-region's near- to mid-term capacity and end-of-life needs. Though relatively small in magnitude, these needs will involve multiple stakeholders (LDCs, transmitter, community members, and municipalities) and could trigger investments impacting local ratepayers. Therefore, an IRRP of a smaller scope is proposed to study the Parry Sound/Muskoka sub-region.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- An IRRP be undertaken to address the needs in the Barrie/Innisfil sub-region;
- An IRRP be undertaken to address the needs in the Parry Sound/Muskoka sub-region; and
- A bulk system study be undertaken to assess the need on M6E/M7E.

The Terms of Reference for the Barrie/Innisfil IRRP is attached in Appendix 2. Similarly, the Terms of Reference for the Parry Sound/Muskoka IRRP is found in Appendix 3.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LAPS	Local Achievable Potential Study
LDC	Local Distribution Company
MNO	Métis Nation of Ontario
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

Appendix 2 – Barrie/Innisfil Sub-Region IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an Integrated Regional Resource Plan of the Barrie/Innisfil sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

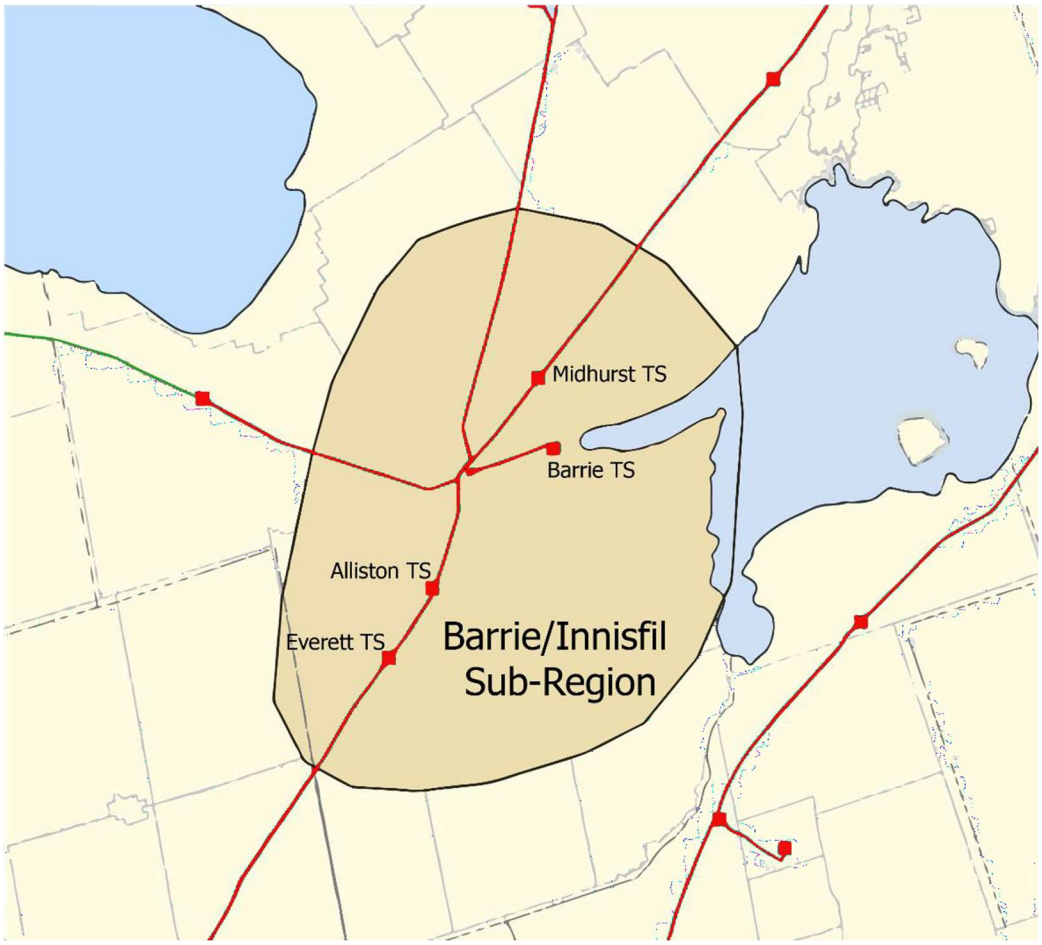
Barrie/Innisfil Sub-Region

The Barrie/Innisfil sub-region is a summer-peaking region that includes the City of Barrie, the Town of Innisfil, and customers in surrounding municipalities supplied from the Barrie, Midhurst, Everett and Alliston transformer stations. The approximate geographical boundaries of the sub-region are shown in Figure A-1.

The sub-region includes all or part of the following municipalities:

- City of Barrie
- Town of Innisfil
- Township of Essa
- Township of Springwater
- Township of Clearview
- Township of Mulmur
- Township of Adjala-Tosorontio
- Town of New Tecumseth
- Town of Bradford West Gwillimbury

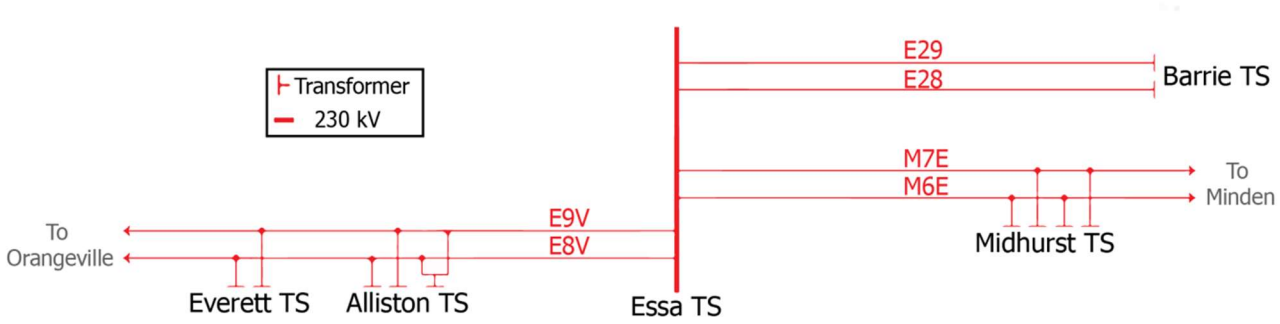
Figure A-1 | Overview of the Barrie/Innisfil Sub-Region



Barrie/Innisfil Electricity System

The electricity system supplying the Barrie/Innisfil sub-region is shown in Figure A-2.

Figure A-2 | Barrie/Innisfil Electricity System



Background

In the last regional planning cycle, the Barrie/Innisfil sub-region IRRP and RIP were published in December 2016 and August 2017, respectively. Studies conducted during the development of these plans triggered a hand-off letter issued to Hydro One Transmission in December 2015. This letter recommended the implementation of the Barrie Area Transmission Upgrade (BATU) project to supply forecast growth in the Barrie and Innisfil areas.

The BATU project, to be in-service in 2022, involves rebuilding and uprating Barrie TS and the E3/4B[4] circuits to 230 kV, as well as retiring Essa auto-transformers T1/T2. This recommendation also included an additional 44 kV feeder supply line to service InnPower load from the uprated Barrie TS. The new 44 kV feeder, as well as InnPower's existing feeder at the time, would be relocated outside of the Hydro One transmission corridor and was expected to help meet InnPower's forecast demand until the mid-2020s.

Long-term recommendations from the previous planning cycle in Barrie/Innisfil included the Barrie TS LAPS (to explore the potential of local demand management resources), as well as continued monitoring of demand growth and local projects to help inform the subsequent planning cycle.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over the next 20 years.
2. To address customer-driven electricity needs by developing a flexible, comprehensive, integrated electricity plan for the Barrie/Innisfil sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Barrie/Innisfil sub-region. The plan is a joint initiative involving Alectra Utilities, InnPower, Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement activities. The plan will integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of facilities in the area, relevant community plans, other bulk system developments, and generation uptake, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Barrie/Innisfil area. Specifically, the following existing infrastructure is included in the scope of this study:

- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E28/29, M6/7E (Essa-Midhurst section)

[4] Now designated as E28 and E29

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS and supply capacity needs of M6/7E) will be assessed by the IESO through a separate bulk system planning process, and assumptions will be coordinated between the regional and bulk plans. Results of the bulk study will be shared with the Technical Working Group as they become available.

The Barrie/Innisfil IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe.
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Barrie/Innisfil sub-region, taking into account system reinforcements committed during the last planning cycle, facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices.
- Establish feasible integrated alternatives to address remaining needs, considering a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Barrie/Innisfil sub-region.
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on sub-region's share of current energy efficiency programs
    - Local Achievable Potential Studies
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements

    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability
    - Load security
    - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions
- End-of-life asset considerations/sustainment plans
    - Transmission assets, in particular end of life segments of 230 kV circuits in the subregion
    - Distribution assets
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator (Team Lead for IRRP)
- Hydro One Transmission
- Alectra Utilities
- InnPower
- Hydro One Distribution

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Barrie/Innisfil IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2020
2. Develop the planning forecast, including scenarios for sensitivity analyses, as required		Long-term planning forecast scenarios	Q4 2020 – Q1 2021
Establish historical coincident and non-coincident peak demand information	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast for LDC service areas	LDCs		
Establish existing, committed and potential DG	LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop planning forecast scenarios for sensitivity analyses	IESO		
3. Provide information on load transfer capabilities under normal and emergency conditions	LDCs	Load transfer capabilities under normal and emergency conditions	Q4 2020 – Q1 2021
4. Provide and review relevant community plans, if applicable	LDCs and IESO	Relevant community plans	Q4 2020 – Q1 2021
5. Complete system studies to identify needs over a twenty-year period - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1 – Q2 2021
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 – Q3 2021
Develop energy efficiency options, with consideration for previous LAPS findings	IESO and LDCs		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Develop local generation options, with consideration for previous LAPS findings	IESO and LDCs		
Develop transmission and distribution options	Hydro One Transmission, and LDCs		
Develop options involving other electricity initiatives (e.g., smart grid, storage)	IESO/ LDCs with support as needed		
Develop portfolios of integrated alternatives	All		
Technical comparison and evaluation	All		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities	Ongoing as required
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	All		
Develop communications materials	All		
Undertake community and stakeholder engagement	All		
Summarize input and incorporate feedback	All		
8. Hand-off wires component of integrated solution	IESO	Hand-off letter to Hydro One	Q1-Q2 2021

Activity	Lead Responsibility	Deliverable(s)	Timeframe
9. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q3 – Q4 2021
10. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	Q1 – Q2 2022

Appendix 3 – Parry Sound/Muskoka Sub-Region IRRP Terms of Reference

1. Introduction and Background

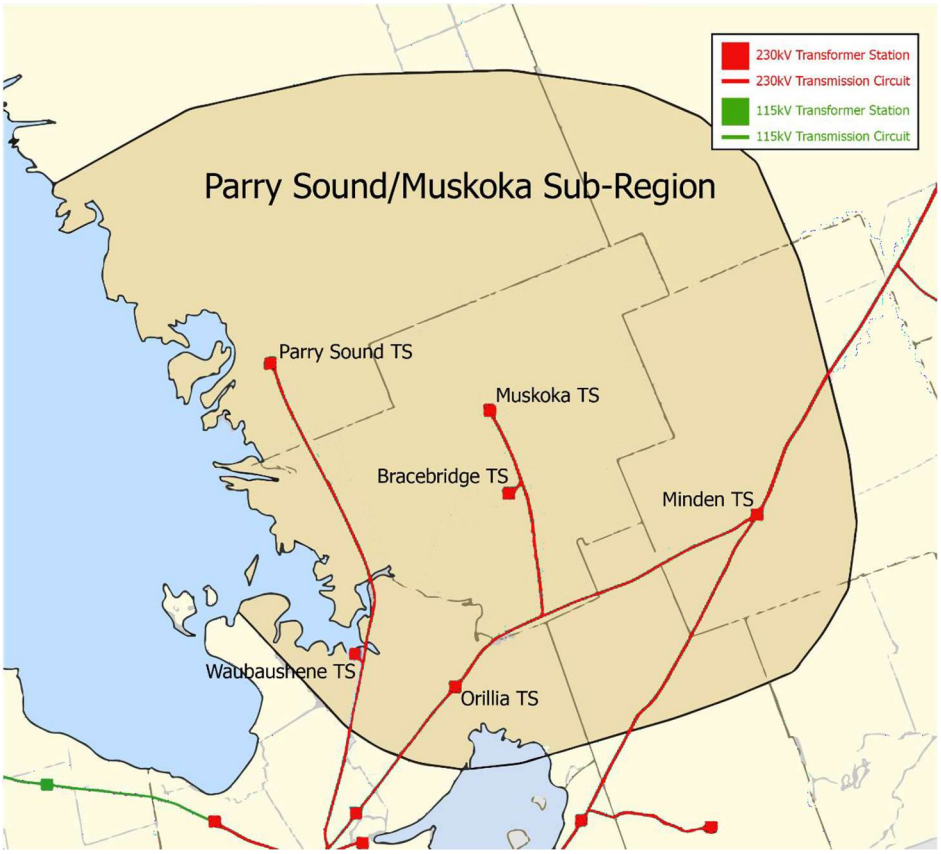
These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables, and timelines for an Integrated Regional Resource Plan of the Parry Sound/Muskoka sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Parry Sound/Muskoka Sub-Region

The Parry Sound/Muskoka sub-region is winter-peaking and it roughly encompasses the Districts of The approximate geographical boundaries of the sub-region are shown in Figure A-3.

Figure A-3 | Overview of the Parry Sound/Muskoka Sub-Region



The sub-region includes all or part of the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan
- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin
- Township of Severn
- Township of Strong

- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

The Parry Sound/Muskoka sub-region also includes the following First Nations and Métis Nation of Ontario councils:

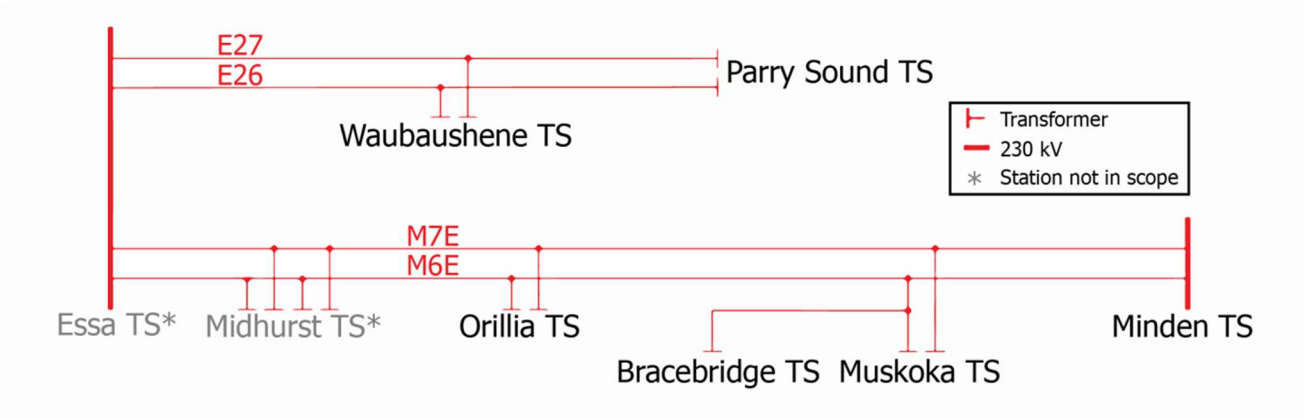
- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama
- MNO Barrie South Simcoe Métis Council
- MNO Moon River Métis Council
- MNO Georgian Bay Métis Council

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Parry Sound/Muskoka Electricity System

The electricity system supplying the Parry Sound/Muskoka sub-region is shown in Figure A-4.

Figure A-4 | Parry Sound/Muskoka Electricity System



Background

In the last regional planning cycle, the Parry Sound/Muskoka sub-region IRRP and RIP were published in December 2016 and August 2017, respectively. Studies conducted during the development of these plans triggered a hand-off letter issued to Hydro One Transmission in March 2017. This letter recommended the implementation of two 230 kV motorized switches on the 230 kV circuits M6/7E at Orillia TS to improve the load restoration capability to the Muskoka and Orillia areas. These switches are expected to be in-service in 2021.

The previous planning studies also recommended the replacement of end-of-life Minden TS transformers (in-service in 2021), the upsizing of the end-of-life Parry Sound TS transformers in 2024, and various distribution-level load transfers between stations (Waubaushene TS to Orillia TS or Midhurst TS; Parry Sound TS to Muskoka TS) to maximize the use of the region's existing electricity system.

Long-term recommendations from the previous planning cycle in Parry Sound/Muskoka included the Parry Sound and Waubaushene LAPS (to explore the potential of local demand management resources), as well as continued monitoring of demand growth and local projects to help inform the subsequent planning cycle.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Parry Sound/Muskoka sub-region over the next 20 years.
2. To develop a flexible, comprehensive, integrated electricity plan for the Parry Sound/Muskoka sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Parry Sound/Muskoka sub-region. The plan is a joint initiative involving Lakeland Power, Newmarket-Tay Power, Alectra Utilities, Elexicon, Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and generation uptake, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Parry Sound/Muskoka area. Specifically, the following existing infrastructure is included in the scope of this study:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS and supply capacity needs of M6/7E) will be assessed by the IESO through a separate bulk system planning process, and assumptions will be coordinated between the Regional and Bulk plans. Results of the bulk study will be shared with the Technical Working Group as they become available.

The Parry Sound/Muskoka IRRP will:

- Prepare a 20-year electricity demand forecast for the appropriate stations and establish needs over this timeframe
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Parry Sound/Muskoka sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices
- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Parry Sound/Muskoka sub-region
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.

    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on sub-region's share of current energy efficiency programs
    - Local Achievable Potential Studies
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation, district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    - Supply capability
    - Load security
    - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records

    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions
- End-of-life asset considerations/sustainment plans
    - Transmission assets, in particular end of life segments of 230 kV circuits in the subregion
    - Distribution assets
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- Hydro One Distribution
- Alectra Utilities
- Elexicon Energy
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Parry Sound/Muskoka IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2020
2. Develop the planning forecast for Parry Sound TS and Waubaushene TS		Long-term planning forecast scenarios	Q4 2020 – Q1 2021
Establish historical coincident and non-coincident peak demand information	IESO		
Establish historical weather correction, median and extreme conditions	IESO		
Establish gross peak demand forecast	LDCs		
Establish existing, committed and potential DG	LDCs		
Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
Develop planning forecast scenarios for sensitivity analyses	IESO		
3. Reconfirm load transfer capabilities from Parry Sound TS and Waubaushene TS	LDCs	Load transfer capabilities under normal and emergency conditions	Q4 2020 – Q1 2021

Activity	Lead Responsibility	Deliverable(s)	Timeframe
4. Provide and review relevant community plans, if applicable	LDCs, First Nations and IESO	Relevant community plans	Q4 2020 – Q1 2021
5. Complete system studies to identify needs - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	IESO, Hydro One Transmission	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1 – Q2 2021
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 – Q3 2021
Develop energy efficiency options, with consideration for previous LAPS findings	IESO and LDCs		
Develop local generation/demand management options, with consideration for previous LAPS findings	IESO and LDCs		
Confirm the transmission and distribution alternatives: advancement of EOL transformer replacement plans and/or load transfers	IESO, Hydro One Transmission and LDCs		
Develop portfolios of integrated alternatives	All		
Technical comparison and evaluation	All		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required

Activity	Lead Responsibility	Deliverable(s)	Timeframe
Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	All		
Develop communications materials	All		
Undertake community and stakeholder engagement	All		
Summarize input and incorporate feedback	All		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q3 – Q4 2021
9. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	Q1 – Q2 2022

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Appendix E

Innisfil Area Supply Alternatives Report

REGIONAL INFRASTRUCTURE PLANNING

SOUTH GEORGIAN BAY – MUSKOKA

INNISFIL AREA SUPPLY ALTERNATIVES

Date: July 5, 2021
Revision: R0

Prepared by: hydro one Transmission

Contributions: alectra utilities, innpower, hydro one Distribution

Preface

This report presents the supply alternatives to address increased load growth in the Innifil area, and advances the ideas and recommendations from the Regional Infrastructure Planning Needs Assessment (NA). It is intended to complement the Scoping Assessment (SA) and IRRP study that is presently being led by the IESO. It will also allow for further exploration of options while highlighting the importance of commencing development work to meet supply needs in the area.

Description

The Regional Infrastructure Plan Needs Assessment (NA) report identified an increased supply capacity need in the Innifil area by 2025. Subsequent to the Needs Assessment, the working group had agreed this need would be further coordinated through an IESO led IRRP. In doing so, it was acknowledged that given the timing and magnitude of the need, development of wires alternatives should be promptly investigated by the effected transmission and distribution utilities.

This document presents alternatives that have been previously discussed as solutions that could help meet Innifil area supply needs. Based on the 2020 Needs Assessment, Innpower's load growth is forecasted to reach 93MW by 2029. The 44kV - 2-feeder supply from Barrie TS will only provide a 50MW supply limit and demand in the area will exceed supply capability in 2025. An Incremental 43MW will need to be supplied by the end of the study period.

Given the need date of 2025, any work associated with long lead deliverables for transmission alternatives should be given consideration for commencement as soon as practical.

Note: The Barrie Area Transmission Reinforcement (BATU) project is presently underway and scheduled to be in-service in 2022. Barrie TS will be upgraded to a new 230/44kV 125MVA transformer station with 8 feeder positions. (6 for Alectra Utilities, 2 for Hydro One Distribution with InnPower as an embedded customer). Each of the following alternatives build upon the final Barrie TS upgrade design.

Supply Alternative Comparison

Alternatives	1	2	3	4
	Inn Power to connect to existing Alectra Feeder as embedded customer	Additional 44kV feeder position from Barrie TS	Load existing 44kV supply feeders beyond normal capacity	Provide 230kV tap connection to Innisfil service territory for new transformer station
Scope / Proposal	To utilize spare capacity at Barrie TS, this alternative will require Inn Power to build a distribution tap to the closest Alectra owned feeder and utilize spare capacity (if available) For this to occur, both station capacity and individual feeder capacity must be within limits.	Innpower will be supplied with 2-44kV feeders from Barrie TS once the BATU project is completed. This alternative seeks to install a 3rd feeder to provide additional supply capacity.	Innpower will be supplied with 2-44kV feeders from Barrie TS once the BATU project is completed. This alternative will require Hydro One Dx to increase loading these two feeders beyond the normal planning capacity while staying within the overall station capacity offered by BATU This alternative would increase each feeder supply capacity by 10MW/feeder for a total of 20MW	This alternative provides increases supply capacity for Innpower by constructing a new 230/27.6kV transformer substation and connecting to the new 230kV transmission lines (E28B/E29B) that will be available post BATU
Impacted Participants	Alectra Inn Power	Hydro One Tx Hydro One Dx Inn Power	Hydro One Dx Inn Power	Hydro One Tx Inn Power
Transmission Considerations	OGCC presently utilizes Barrie TS M4 feeder as a backup supply and this supply requirement for Hydro One will remain in place following the completion of the BATU project.	Barrie TS will be built to follow Hydro One standard 230/44kV Jones arrangement with 8 feeder positions. To accommodate an additional feeder, the existing layout and station footprint will require redesign. Modifications to the low voltage steel structure, access road, relocation of capacitor banks, and fence extension will be required.	No significant transmission considerations	Provide approximately 7km new 230kV double circuit line tap from E28B/E29B circuits to the new substation.

Alternatives	1	2	3	4
	Inn Power to connect to existing Alectra Feeder as embedded customer	Additional 44kV feeder position from Barrie TS	Load existing 44kV supply feeders beyond normal capacity	Provide 230kV tap connection to Innisfil service territory for new transformer station
		Note: This will also deviate from Hydro One Tx standard DESN arrangement and planning guidelines		
Distribution Considerations	Alectra M4 feeder provides low exposure backup for OGCC, and its short feeder length and geographic location restricts new load/tap connections. This ensures frequency and duration of outages to M4 are kept to a minimum helping to maintain critical supply backup. Alectra has indicated the feeder capacity is not available on the remaining feeders closest to Innpower service territory, due to its existing load and anticipated growth.	There are known physical challenges due to clearances adding additional complexity for a new feeder egress. To build a new feeder, an underground egress would be required transitioning to an overhead lines and will follow a similar path to the existing feeders travelling south to Innisfil.	Voltage support will be required along each of the 2-44kV feeders to maintain acceptable voltage profile on the feeders. Further Dx studies (coordinated with Innpower) are needed to determine the location of regulating stations (RS)	Inn Power will construct and own a new 230/27.6 83MVA transformer station.
Implementation Timing	2-3yrs	2-3yrs	2-3yrs	3-5 years
Regulatory Consideration	N/A	Both Transmission & Distribution bypass charges may apply if load is transferred at a later date in favor of another solution.	Distribution bypass charges may apply if load is transferred at a later date in favor of another solution.	OEB S.92 (leave to construct) required
Environmental Approval Risk	Low	Low	Low	Medium (Class EA required)
Indigenous Relations Risk	Low	Low	Low	Low

	1	2	3	4
Alternatives	Inn Power to connect to existing Alectra Feeder as embedded customer	Additional 44kV feeder position from Barrie TS	Load existing 44kV supply feeders beyond normal capacity	Provide 230kV tap connection to Innisfil service territory for new transformer station
Solution Valid until	50MW+0MW* =50MW 2025 Note: * capacity is not available at this time.	50MW+25MW=75MW 2027	50MW+20MW=70MW 2027	50MW+ (100MW) >2030
Costs[1]	Costs = Not Appplicable. Costs have not be explored as there is no available feeder capacity. Should capacity become available in the future, estimates can be obtained from the working group if practical to do so.	HONI Transmission - $5M HONI Distribution – $15M Total - $20M The cost of a new feeder position will be substantially higher than what would normally be expected for this type of work for both Hydro One and Hydro One Distribution due to the egress challenges outside the station and physical space limitations inside Barrie TS.	HONI Transmission – N/A HONI Distribution - $8M Total - $8M	HONI Transmission - $14M Innpower - $30M Total - $44M
Meets the Need	This solution is only viable if OGCC backup control strategy changes, and feeder capacity on the closest feeders from Alectra becomes available. Any spare capacity that would be available if this alternative proceeds would still fail to meet the full supply needs within the study period, and	A new feeder position will provide up to 25MW supply capacity, which will help to delay the need to 2027. Another solution will need to be implemented to meet the full capacity needs beyond 2027 which would be at additional cost to this alternative or to replace this alternative.	This alternative will provide up to 20MW increased supply capacity which will help to delay a capacity need until 2027. Another solution will need to be implemented to meet the full capacity needs beyond 2027 which would be at additional cost to this alternative or to replace this alternative.	This alternative will provide the supply capacity needed well beyond the study period. The station is presently being sized with 83MVA transformers will provide sufficient supply capacity for area load growth and this alternative can be utilized as standalone solution to meet the needs without additional interim investments.

[1] Costs presented in this table are planning level allowances and include the scope to provide increased supply up to Innpower delivery point. Costs incurred by Innpower downstream on the distribution system are not part of the scope of this report, and can assessed as the project advances. Examples of such downstream costs include but not limited to; additional transformation requirements, new feeder construction / extensions within Innpower's service territory.

Alternatives	**1**	**2**	**3**	**4**
	Inn Power to connect to existing Alectra Feeder as embedded customer	Additional 44kV feeder position from Barrie TS	Load existing 44kV supply feeders beyond normal capacity	Provide 230kV tap connection to Innisfil service territory for new transformer station
	will need to be combined with alternate solutions.	This alternative is not viable as a standalone option and still must be combined with option 4 to meet supply needs within the study period.	This alternative is not viable as a standalone option and still must be combined with option 4 to meet supply needs within the study period.	

Recommendation

Option 4 provides a robust transmission solution to meet InnPower's demand forecast, and will also allow for future load growth beyond the study period. This solution can be implemented in time for Inn Power supply needs of 2025 provided development work starts as soon as possible to identify line routes/risks and mitigation plans as needed. A combination of Dx and Tx solutions *may* be required if the projected load growth is uncertain or development work for alternative 4 is delayed. All efforts shall be made to avoid temporary/interim investments that will still be deemed insufficient to meet the ultimate supply needs.

Therefore, it is recommended that Hydro One Transmission and InnPower proceed with development work for option 4 in Q2 2021 in order meet an in-service date of 2025.

In parallel with this undertaking, the IESO led IRRP presently underway will refresh both the load forecast and CDM/DG assumptions to help verify the timing of the supply capacity needs.

Figure 1 – NA Load Forecast for Options Analysis

Load Forecast Post-BATU

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LV Cap bank	LTR (MW)	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Barrie TS	T1/T2	170	Y	162	Gross Peak (Alectra)				65.1	67.1	69.2	71.3	73.5	75.5	77.4	79.4	81.5	83.6
					Gross Peak (InnPower)				19.0	23.2	30.1	39.8	48.8	56.8	65.4	75.6	84.3	92.9
					Gross Peak (Total)				84.1	90.3	99.3	111.2	122.3	132.2	142.8	155.0	165.8	176.5
					CDM (MW)				0.7	0.9	1.4	2.0	2.7	3.4	4.1	5.5	6.3	7.0
					DG (MW)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
					Net Load Forecast	93.9	119.5	127.9	83.4	89.4	97.9	109.1	119.7	128.8	138.8	149.5	159.5	169.5



Appendix F

Integrated Regional Resource Plan – Barrie/Innisfil



Integrated Regional Resource Plan

Barrie/Innisfil
May 2022

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List of Acronyms

APO	Annual Planning Outlook
BKF	Breaker Failure
CEP	Community Energy Plan
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
GHG	Greenhouse Gas
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Electricity Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long Term Emergency
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-Wires Alternatives
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RO	Reliability Outlook
SIA	System Impact Assessment

SGBM	South Georgian Bay Muskoka
TS	Transformer Station

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013- 0066.

This IRRP was prepared on behalf of the Technical Working Group of the Barrie/Innisfil sub-region which is composed of the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Alectra Utilities
- InnPower Corporation

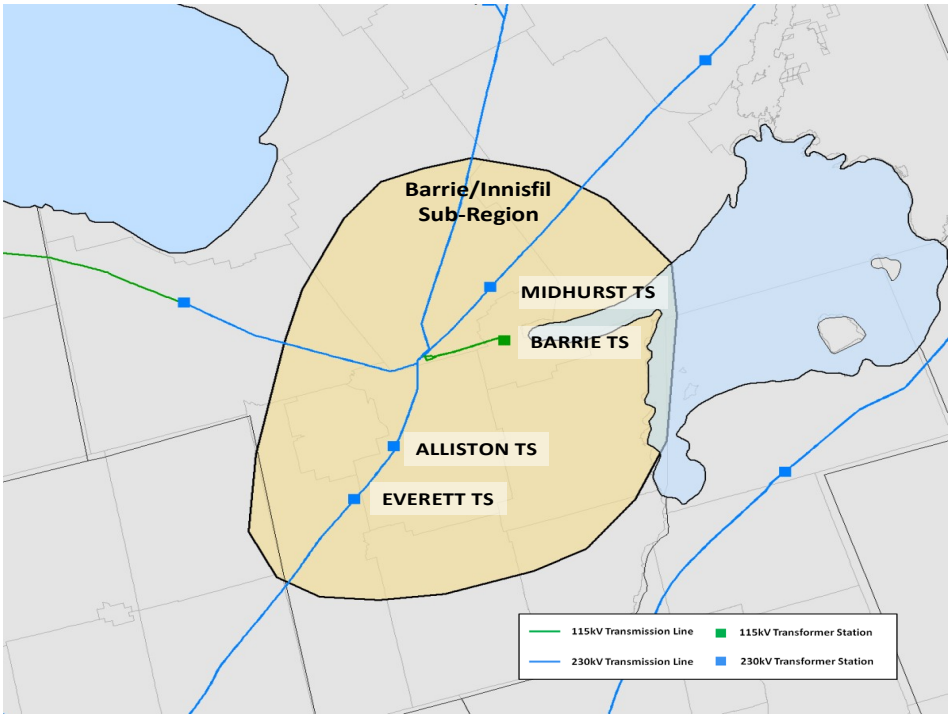
The Technical Working Group assessed the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Barrie/Innisfil Technical Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to appropriate community engagement and consultations and obtaining necessary regulatory approvals.

1. Introduction

This IRRP for Barrie/Innisfil sub-region addresses the regional electricity needs over the study period, i.e., from 2021 to 2040. The Barrie/Innisfil sub-region is located in the South Georgian Bay Muskoka region and it encompasses the City of Barrie, the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury, and the townships of Essa, Springwater, Clearview, Mulmur and Adjala-Tosorontio. Figure 1 shows the overview of the Barrie/Innisfil sub-region.

Figure 1 | Overview of the Barrie/Innisfil Sub-Region and Transmission System[1]



The sub-region is electricity supplied by the following three local distribution companies (LDC), namely: Hydro One Networks Inc. (Distribution), Alectra Utilities and Innpower Corporation. The transmission asset owner is Hydro One Networks (Transmission). This IRRP report was prepared by the IESO on behalf of the Technical Working Group composed of the three Local Distribution LDCs and transmitter.

[1] Barrie TS is currently being upgraded to 230 kV supply

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is conducted through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for each of the province's 21 electricity planning regions, including the South Georgian Bay Muskoka region, at least once every five years.

This is the second cycle of regional planning for the Barrie/Innisfil sub-region. This cycle began in 2020 with the publication of the South Georgian Bay Muskoka Needs Assessment Report. This was followed by a Scoping Assessment which identified needs that should be addressed through the IRRP process and recommended two IRRPs; one for Parry Sound/Muskoka sub-region and another for Barrie/Innisfil sub-region. A Technical Working Group was then formed for Barrie/Innisfil to gather data, identify electricity needs and develop options and recommendations which are included in this IRRP.

This IRRP report is organized as follows:

- A summary of the recommended plan for the Barrie/Innisfil sub-region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Barrie/Innisfil sub-region and the study scope are discussed in Section 4;
- The demand forecast and conservation and demand management (CDM) and distributed generation (DG) assumptions are described in section 5;
- Electricity needs in the Barrie/Innisfil sub-region are presented in Section 6;
- Alternatives and recommendations for addressing needs are described in Section 7;
- A summary of engagement activities is provided in section 8; and
- The plan conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

The Barrie/Innisfil IRRP provides recommendations to address the electricity needs of the sub-region over the next 20 years. The needs were identified based on the sub-region's demand forecast and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that considers: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from communities and stakeholders.

The Barrie/Innisfil IRRP recommendations below are organized under a near/medium-term plan and a longer-term plan. The near/medium-term timeframe is seven to ten years out while the longer-term timeframe is beyond ten years. The timeframe distinction reflects the different levels of forecast certainty, lead time for development and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on the investments that will be needed in a near future while remaining flexible to new information.

2.1 Near/Medium-Term Plan

Table 1 below lists the recommended actions to address the sub-region's needs together with the details of their implementation for the near/medium-term. The recommendations are further discussed below.

Table 1 | Summary of Near/Medium-term Plan for Barrie/Innisfil IRRP

Need Description	Recommendation	Lead Responsibility	Required by
Barrie TS to reach its summer 10-day LTR and supply capacity constraint at 44 kV feeder level	Construct a new 230/27.6 kV transformer substation	Hydro One and InnPower	2025
Everett TS to reach its summer 10-day LTR	Adjust the CT ratio of transformer breakers	Hydro One	2025
Sections of E8V/E9V circuits to reach end-of-life	Like for like replacement	Hydro One	2027

2.1.1 Transformer CT Ratio Adjustment at Everett TS and New 230/27.6 kV Transformer at Barrie TS

Everett TS and Barrie TS are both expected to reach their summer 10-day LTR in the near/medium-term timeframe.

Everett TS peak demand forecast will exceed its rating by 2025. The recommended solution for this need is to adjust the CT ratio of the transformer breakers[2]. This will provide the ability to utilize the full supply capability of the transformers at Everett TS and alleviate the need.

Barrie TS peak demand forecast will exceed its rating by 2027. Also, there is a supply constraint on the distribution level at the 44 kV feeder starting in 2025. For this distribution level need, minor capacity increases can be accommodated on the 44 kV system but only on an emergency basis. The recommended solution is to construct a new 230/27.6 kV transformer substation which would connect to the upgraded circuits E28B/E29B that will be in place once the Barrie Area Transmission Upgrade (BATU) reinforcements are in-service[3].

2.1.2 E8V/E9V Like-for-Like Replacement

Sections of circuits E8V/E9V will reach end-of-life by 2027. A like-for-like approach is recommended for the replacement of these assets from a regional perspective.

2.2 Longer-Term Plan

In addition to the near/medium-term plan above there are the following items to monitor and develop in the longer-term.

2.2.1 Monitor Growth at Midhurst TS and Alliston TS

Midhurst TS and Alliston TS are expected to reach capacity by 2035 and 2037 respectively. Given the timing of the need, no firm recommendation is required at this time. The Technical Working Group will continue to monitor demand growth in the area and revisit these needs in the next cycle of regional planning.

2.2.2 Consider CDM in Next Cycle of Regional Planning for M6E/M7E Essa x Midhurst circuit

There is a thermal capacity need on one MxE 230 kV circuit section between Essa and Midhurst for the loss of the companion MxE circuit starting in 2034. While this need is expected to arise in the longer-term, potential options were contemplated to inform future plans.

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[2] Current transformers are instrument transformers used for measurements for metering/loading data or for generating signals for protective devices. Since the current on the actual system is usually too high to be either economically or practically measured or to supply a signal to a protective device, the current transformer lowers the current to an acceptable level. The ratio between these two current values is the "CT ratio"

[3] The BATU project involves rebuilding and uprating Barrie TS and the E3/4B circuits to 230 kV circuits E28/29 and retiring Essa T1/T2

The analysis showed that incremental, cost-effective CDM is potentially a good candidate to defer this need, when considering the need characteristics. Given the time of the need, no firm recommendation is required at this time; however, it is recommended to continue to consider incremental, cost-effective CDM as an option in between planning cycles and bring these insights into the next cycle of regional planning for the region.

2.2.3 Supporting Community Energy Plans and Monitoring Energy Efficiency and Electrification Trends

There are two Community Energy Plans (CEP) identified in the Barrie/Innisfil sub-region. The first is the Barrie Community Energy and Green House Gas (GHG) Emission Reduction Plan which was presented to Council in March 2022. This plan will help the community better understand current energy consumption, identify energy efficiency opportunities and help meet the community's climate priorities.

The second plan is for the Town of Innisfil. The Community Strategic Plan: Innovative Innisfil 2030 was approved by Council in October 2019. This plan will guide projects across the Town of Innisfil over the next ten years to help Innisfil become a unique and innovative community.

While the IRRP seeks to align with these plans where possible, not all of the objectives fall within the scope of the regional planning nor the IESO's mandate. For example, absent of provincial government policy, the IESO is technology agnostic and will generally choose the most economic option that adequately resolves the need and meets applicable reliability standards. Greenhouse gas emissions are considered in the IRRP's options analysis by accounting for the carbon price associated with emitting resources, but the IESO does not have emission reduction targets unless directed by government policy. Furthermore, while regional planning is responsible for ensuring electricity ratepayer value and minimizing electricity costs, the IESO relies on government policy for broader socioeconomic considerations.

There are three CEP objectives that the IESO and regional planning can play a role in supporting. First, the IESO recognizes that distributed energy resources (DER) are becoming increasingly prevalent and features prominently in many CEPs. DERs can provide benefits to both customers as well as the distribution and transmission systems. By enabling DERs to provide wholesale services, system costs can be reduced and opportunities for customers and investors can be increased. The IESO's Enabling Resources Program (ERP) will produce a 5-10 year plan to enable resources to provide services they cannot or cannot fully currently provide. The ERP has identified storage, hybrids, and DERs as high-priority opportunities. The IESO developed a DER roadmap in the fall of 2021 to provide clarity on IESO objectives, initiatives, and timing for DER integration and is completing a DER Potential Study by June 2022. More information can be found on the Distributed Energy Resource Roadmap engagement page.

Second, the Technical Working Group will continue to support and monitor energy efficiency uptake. Conservation expected to be achieved through codes, standards, and program delivery has already been included in the planning forecast as described in Section 5.4. On September 30, 2020, the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system and ensures energy efficiency can continue to play a role in meeting the region's needs. The Technical Working Group will monitor uptake of the CDM framework as well as energy efficiency initiatives in CEPs and assess the impact of these additional savings on the timing of local reliability needs.

Finally, the Technical Working Group will monitor electrification trends and their impact on the demand forecast. The Technical Working Group recognizes that many CEPs are calling for ambitious electrification targets as a means to achieve carbon emission reductions. It is not yet clear how impactful electrification will be to the load forecast in the near-term but it could drive significantly higher demand in the long term that will necessitate new electricity supply into the area. While it is still difficult to establish when firm investments or infrastructure reinforcements will be needed, it is prudent to prepare for a future where electricity demand could potentially be significantly higher than forecast.

2.3 Bulk Area Needs

One of the needs identified as part of this IRRP is linked to the bulk transmission system in the broader region. This need is a thermal capacity need on one of the Essa 500/230 kV autotransformers for loss of the companion autotransformer arising in 2022. For loss of Essa T4, Essa T3 is at 100% of its 10-day summer Limited Time Rating (LTR) in 2022. This will be considered as part of IESO's bulk planning process.

3. Development of the IRRP

3.1 The Regional Planning Process

In 2013, the OEB created a formal process for regional planning which is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The regional planning formal process sets out 21 different electricity planning regions for the province. Regional planning assesses the interrelated needs of a region over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, demand forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions to be undertaken.

The process consists of four main components:

1. A Needs Assessment, led by the largest transmitter in the region, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, which identifies the most appropriate planning approach to address identified needs;

3. An IRRP, also led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A Regional Infrastructure Plan (RIP), led by the transmitter, which provides further details on recommended wires solutions.

Further details on the components of the regional planning process in Ontario and the IESO's approach to regional planning can be found in Appendix A.

In addition to regional planning, there are also bulk system planning and distribution network system planning processes. Bulk system planning typically considers the 230 kV and 500 kV network and examines province-wide system issues whereas distribution network planning considers the supply of electricity within an LDC's system Regional planning is the intersection of those two.

A review of the regional planning process was finalized in 2021 following the completion of the first cycle of regional planning for all 21 regions. The Regional Planning Process Review Final Report is published on the IESO's website.

3.2 Barrie/Innisfil and IRRP Development

The process to develop the Barrie/Innisfil IRRP was initiated following the publication of Hydro One's South Georgian Bay Muskoka Needs Assessment report in April 2020 and the IESO's Scoping Assessment report in November 2020. The Scoping Assessment report recommended that the needs identified for the Barrie/Innisfil sub-region be considered through an IRRP in a coordinated regional

approach. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options and recommend solutions in the sub-region.

4. Background and Study Scope

This is the second cycle of regional planning for the Barrie/Innisfil sub-region. During the first cycle of regional planning, a Needs Assessment was conducted for the South Georgian Bay Muskoka Region in March 2015 that was led by Hydro One Networks Inc. Transmission. After reviewing the needs identified in the report, the Technical Working Group recommended that further regional coordination should be considered and a Scoping Assessment was published in June 2015 which recommended coordinated planning through an IRRP. Subsequently, the IRRP for Barrie/Innisfil was published in December 2016 and the RIP was published in August 2017.

This regional planning cycle started with a Needs Assessment published by Hydro One in April 2020, which identified several needs requiring further regional coordination. This was followed by a Scoping Assessment published in November 2020. The report recommended that an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2021.

4.1 Study Scope

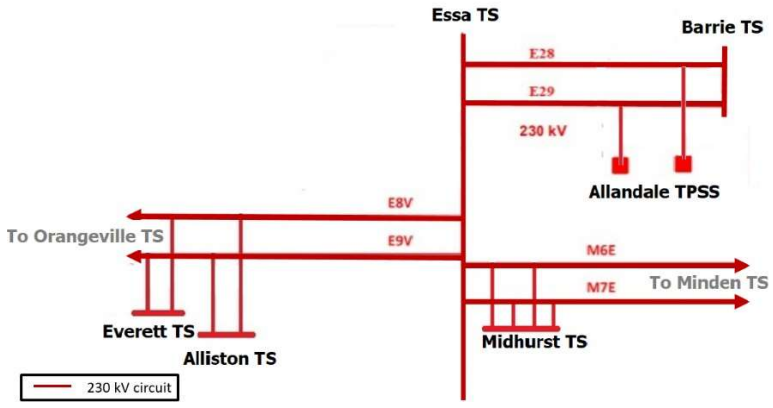
This IRRP develops and recommends options to meet the electricity needs of the Barrie/Innisfil sub-region. The plan was prepared by the IESO on behalf of the Technical Working Group. The plan includes consideration of forecast electricity demand growth, CDM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The needs addressed in this IRRP include adequacy, security and relevant end-of-life asset considerations.

The following transmission facilities were included in the scope of this study:

- 230/115 kV autotransformers at Essa Transformer Station (TS)
- Stations: Alliston TS, Barrie TS, Everett TS, Midhurst TS
- Transmission circuits: E8V/9V, E28/29, M6/7E (Essa to Midhurst section)

The single line diagram of the Barrie/Innisfil sub-region studied is shown in Figure 2 below.

Figure 2 | Single Line Diagram of Barrie/Innisfil Sub-Region



The Barrie/Innisfil sub-region is supplied from the two 500/230 kV autotransformers at Essa TS. These transformers form part of the bulk transmission system, as they are impacted by changes in the broader Ontario electricity system, in addition to the local distribution system. Specifically, the autotransformers are impacted by bulk power system flows on the north-south transmission interface, driven by changing generation and demand patterns in northern and southern Ontario. Therefore, regional needs pertaining to these autotransformers must also be considered from a bulk system perspective and coordinated accordingly.

The Barrie/Innisfil IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the Load Meeting Capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs are established by applying ORTAC and NERC planning criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO controlled grid as described in section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;
- Engaging with the community on needs, findings and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions and recommendation within a detailed plan.

4.2 Related Bulk System Planning Studies

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV autotransformers at Essa TS) will be assessed by the IESO through a separate bulk system planning process, and assumptions will be coordinated between the regional and bulk plans.

5. Electricity Demand Forecast

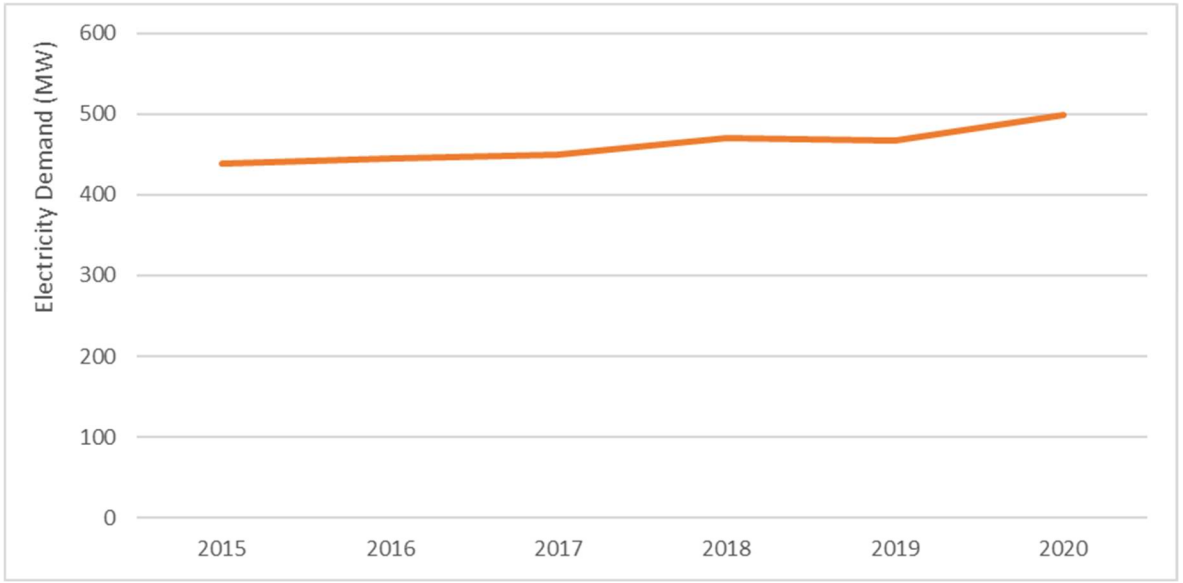
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the Barrie/Innisfil sub-region. It highlights the assumptions made for peak demand forecasts including the contribution of CDM and distributed generation to reducing peak demand. The resulting net demand forecast, termed the planning forecast, is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Barrie/Innisfil sub-region, the peak loading hour for each year occurs in the summer.

5.1 Historical Electricity Demand

In the Barrie/Innisfil sub-region, electricity demand is primarily driven by residential and commercial customers and typically peaks during the summer months. In the summer, air conditioning plays a significant role in contributing to peak electricity demand. The historical demand is shown in Figure 3 and has been adjusted for weather-related impacts. The figure below shows a steady increase in the summer electricity demand needs of the sub-region, reaching a peak of 500 MW in 2020; notably, there is a significant increment from 2019 to 2020 impacted primarily by the weather conditions. The Technical Working Group determined 2020 to be the base year to be used for developing the planning demand forecast.

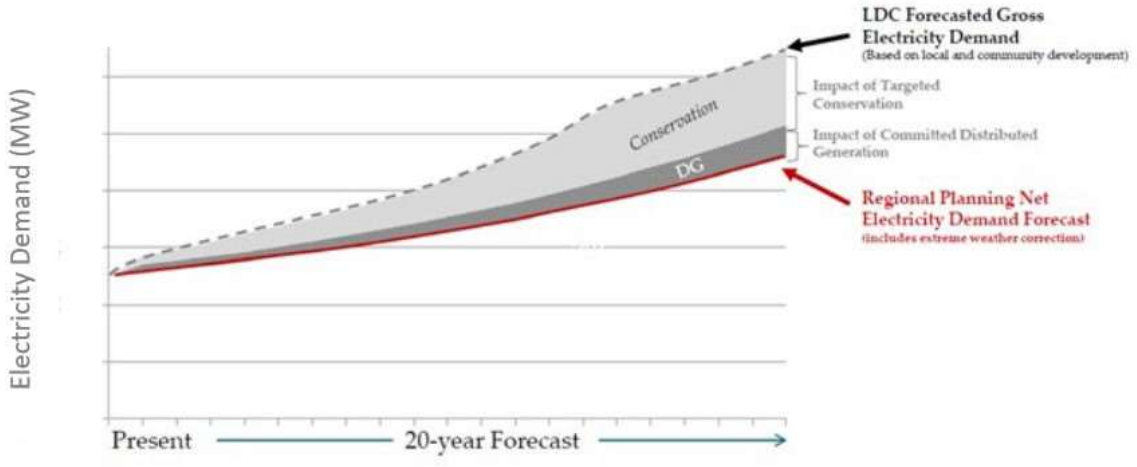
Figure 3 | Historical Summer Peak Demand – Barrie/Innisfil Sub-region



5.2 Demand Forecast Methodology

A 20-year regional peak demand forecast was developed to assess reliability needs for the Barrie/Innisfil sub-region; Figure 4 shows the steps taken to develop this. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions i.e., normal weather, were provided by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation savings and DG contracted through previous provincial programs such as FIT and microFIT. The forecasts were then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments to assess the electricity needs in the region. Additional details related to the development of the demand forecast are provided in Appendix B.

Figure 4 | Development of the Demand



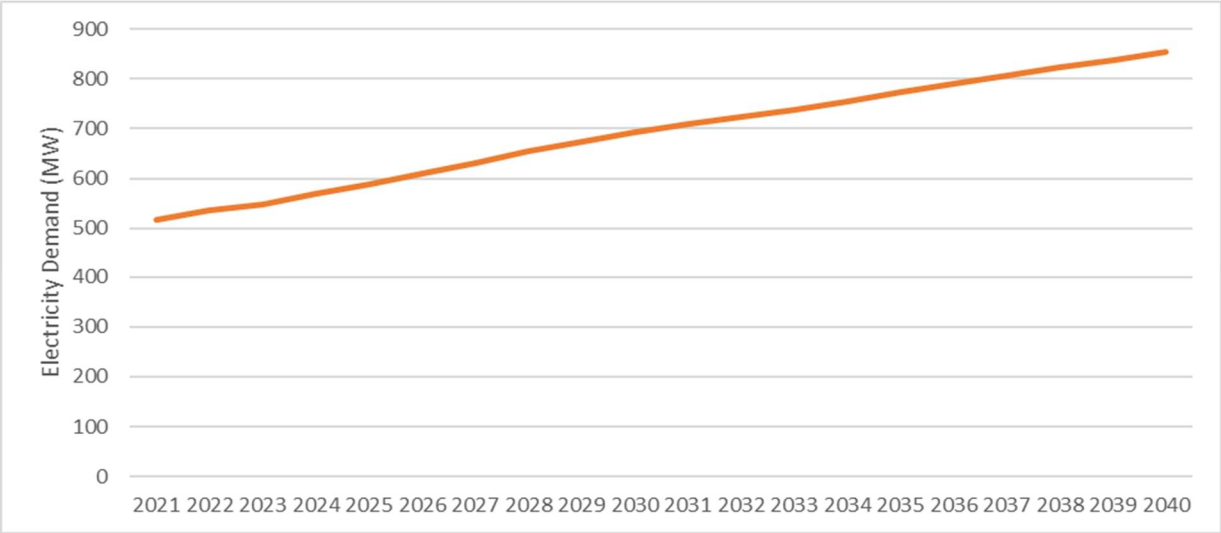
5.3 Gross LDC Forecast

All participating LDCs in the Barrie/Innisfil sub-region provided a gross demand forecast at the station level or at the station bus level for multi-bus stations. LDCs have a better understanding of future local demand growth and drivers than the IESO since they have more direct involvement with their customers. The LDC gross demand forecasts include known connection applications and account for increases in demand due to new or intensified development, economic growth, changes in consumer behaviour, etc. Increases in demand due to new or intensified development were captured through a sensitivity analysis. An example of this is the new Allandale Traction Power Substation (TPSS) (47.2 MW), which will be supplied from uprated circuits E28/E29.

Most LDCs cited alignment with municipal and regional official plans and credited them as a primary source for input data. LDCs are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, but not for the impact of future DG or new conservation measures, such as codes and standards and CDM programs, which are accounted for later in the process. The gross LDC forecast assumes median on-peak weather conditions. More information on the LDCs' demand forecast methodology can be found in Appendix B.

The total gross coincident LDC forecast in the next 20 years for both summer and winter weather is shown in Figure 5 below.

Figure 5 | LDC Coincident Gross Summer Demand Forecast – Median Weather



5.4 Contribution of Conservation to the Demand Forecast

CDM helps in meeting Ontario's electricity needs by reducing demand. This is achieved through a mix of codes and equipment standards amendments as well as CDM program-related activities.

Demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers. Program-related activities include Save on Energy programs, as well as those that are being implemented as part of the 2021-2024 CDM framework.

For the Barrie/Innisfil sub-region, the total forecast conservation savings at the time of summer peak are shown in Table 2 for a selection of the forecast years. These savings are subtracted from the gross median demand forecast as described in Section 5.6. Additional information is provided on Appendix B.

Table 2 | MW Savings from Conservation and Demand Management

Year	2022	2024	2026	2028	2030	2032	2034	2036	2038	2040
Summer Savings (MW)	12	25	32	37	41	42	43	44	46	47

5.5 Contribution of Distributed Generation to Demand Forecast

In addition to conservation resources, DG in the Barrie/Innisfil sub-region is also forecasted to offset peak demand requirements. The resources that were included in the DG forecast reflect resources that have contracts with the IESO as a result of previous procurement programs, such as the FIT and microFIT programs. In the Barrie/Innisfil sub-region, the contracted DG resources are all solar projects. The effective capacity, i.e., the MW output at the time of regional peak, was determined at a resource level, and the data was aggregated at a station level in order to put together a forecast specifying the estimated peak demand reduction due to DG output.

From 2021 to 2033, the expected annual peak demand contribution of contracted DG in the Barrie/Innisfil sub-region is 5.8 MW, going down to 2.35 MW in 2034 and 0 MW in 2040.

The DGs included in the Barrie/Innisfil IRRP are distributed connected from the following stations:

- Alliston TS
- Barrie TS
- Everett TS
- Midhurst TS

5.6 Net Extreme Weather Planning Forecast

The net extreme weather planning forecast, also known as the "planning" forecast, is the coincident peak demand forecast for the sub-region and is used to carry out system studies for identifying potential needs in the Barrie/Innisfil sub-region. This forecast is created in three steps:

1. The gross median weather forecast, provided by the LDCs, is adjusted to extreme weather conditions, according to the methodology described in Appendix B. The result is the gross extreme weather forecast.
2. The impacts of forecast CDM savings and DGs output are added to the gross extreme weather forecast which results in a net extreme weather forecast, or planning forecast.
3. A coincidence factor is applied to convert the forecast to non-coincident. The coincidence factor is based on the contribution of each station to the group's coincident peak over the past five years. Non-coincident station forecasts are utilized for assessing the capacity adequacy of each transformer station in the sub-region.

Figure 6 and Figure 7 below show the net extreme weather winter and summer forecasts for the Barrie/Innisfil sub-region. The figures also show the median gross weather forecast and the extreme gross forecast.

Figure 6 | Summer Net Extreme Weather Demand Forecast

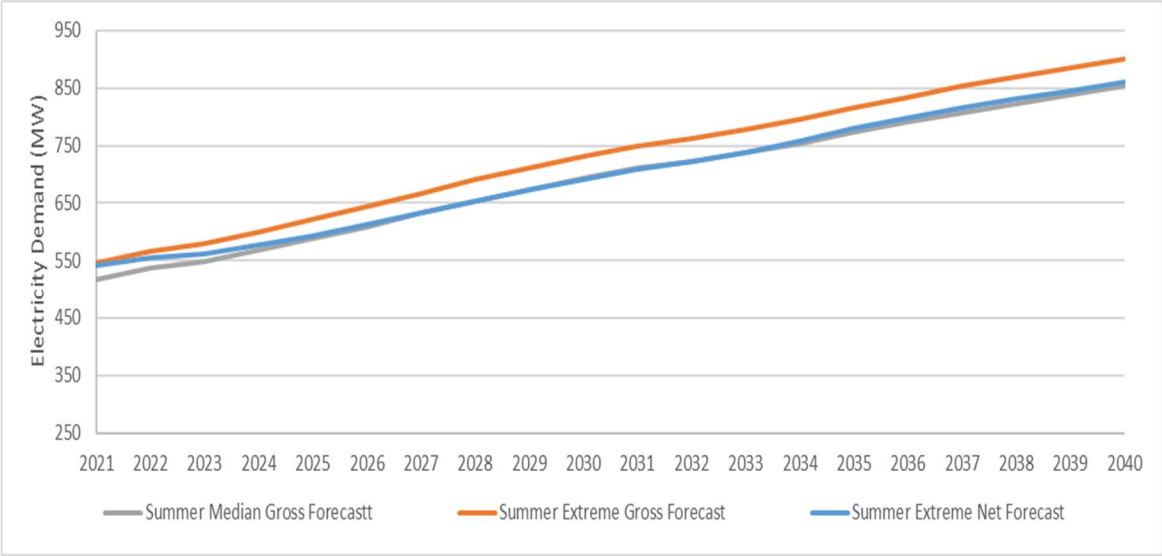
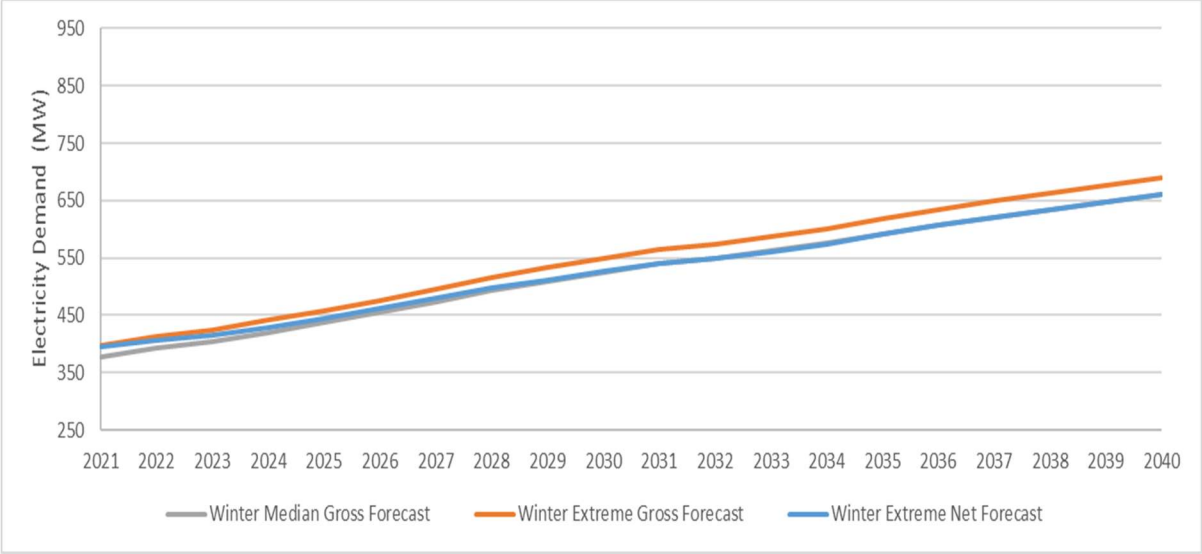


Figure 7 | Winter Net Extreme Weather Demand Forecast



5.7 Load Profiling

In addition to the annual peak demand forecast, hourly load profiles (8,760 hours per year over 20 year forecast horizon) for a number of stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. These profiles are used to quantify the magnitude, frequency and duration of needs to better evaluate the suitability of non-wires alternatives options.

Additional load profile details including summary tables and hourly heat maps for each need can be found in Appendix B.

5.8 Sensitivity Scenario

A sensitivity scenario was performed for higher demand. This higher demand scenario is to take into account a variety of factors that could drive demand higher; these include but are not limited to electric vehicles charging infrastructures and electrified space heating installations in the sub-region. For this, a growth factor of 5% was applied equally to each LDC's station in the sub-region to determine the impact this would have on the need dates identified in system studies.
The higher demand scenario will not be used to drive any firm recommendations for this IRRP; however, it will help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can be useful for communities conducting Community Energy Plans, for the TWG in determining areas to monitor in future cycles of regional planning, and for communities and stakeholders as they think about various projects in the sub-region.

6. Electricity System Needs

6.1 Needs Assessment Methodology

Based on the net extreme weather planning demand forecast, the transmitter's identified end-of-life asset replacement plans and the application of ORTAC and North American Electric Reliability Corporation (NERC) TPL-001-4 Standard, the Technical Working Group identified electricity needs for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL-001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Refurbishment Needs** describe the needs identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset and its condition. Replacement needs identified in the near-and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium-to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results can be found in Appendix D. The needs identified are discussed in the section below.

6.2 Needs Identified

Table 3 below summarizes the needs identified for the Barrie/Innisfil sub-region.

Table 3 | Summary of Needs for Barrie/Innisfil Sub-Region

No.	Need	Need Description	Need Date
1	Alliston Station Capacity	Alliston TS demand forecast will exceed summer 10-day LTR	2037
2	Barrie Station Capacity	Barrie TS demand forecast will exceed summer 10-day LTR	2027
3	Everett Station Capacity	Everett TS demand forecast will exceed summer 10-day LTR	2025
4	Midhurst Station Capacity	Midhurst TS demand forecast will exceed summer 10-day LTR	2035
5	M6E/M7E Supply Capacity	After a loss of either M6E or M7E, the remaining circuit will exceed its LTE	2034
6	End-of-Life refurbishments	Sections of M6E/M7E and E8V/E9	various
7	Essa Bulk System Supply	Essa transformer overload of loss of remaining 500/230 kV autotransformer	Today

Figure 8 below summarizes the location of the needs in the Barrie/Innisfil sub-region.

Figure 8| Location of Needs in Barrie/Innisfil Sub-region



6.2.1 Station Capacity Needs

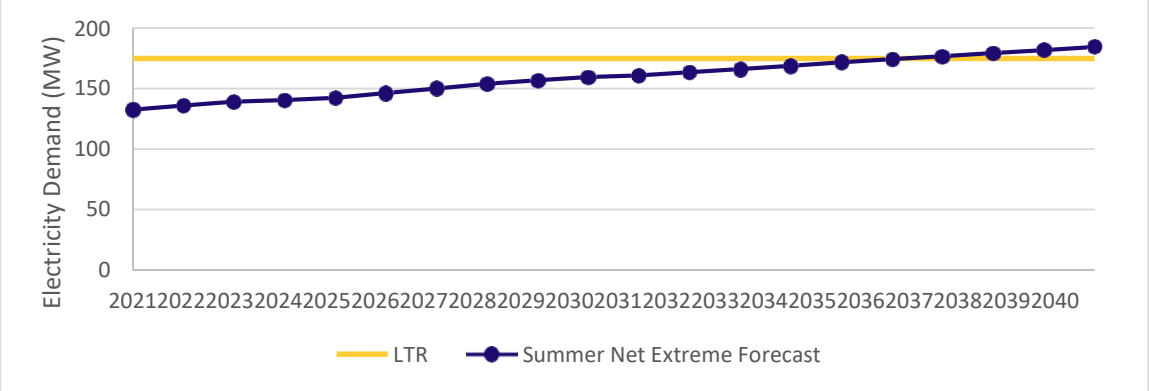
Table 4 and Figure 9 to Figure 12 below show transformer capacity limitations for the Barrie/Innisfil sub-region. In the near/mid-term, there are capacity limitations at Barrie TS and Everett TS. There is also a supply capacity constraint at the 44 kV feeder level for Barrie TS starting in 2025 at the distribution level. The summer demand forecast will exceed the 10-day LTR by 2027 for Barrie TS and 2025 for Everett TS. In the long-term there are capacity needs for Alliston TS in 2037 and Midhurst in 2035.

In the higher demand sensitivity scenario, the station capacity need is advanced by one year for Barrie TS and three years for Everett TS.

Table 4 | Step-down Station Summer 10-day LTR Rating and Peak Demands

Station	10-day LTR Rating (MW)	2022 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Alliston TS	175.0	136.1	142.3	159.5	184.3
Barrie TS	172.8[4]	105.3	157.2	225.7	254.5
Everett TS	86.0	83.1	86.2	94.8	167.9
Midhurst TS[5]	311.0	275.0	263.2	284.7	339.1

Figure 9| Alliston TS Capacity Need



[4] This summer LTR rating is post-BATU

[5] Midhurst TS consists of 2 Dual Element Spot Network (DESN) transformers

Figure 10| Barrie TS Capacity Need

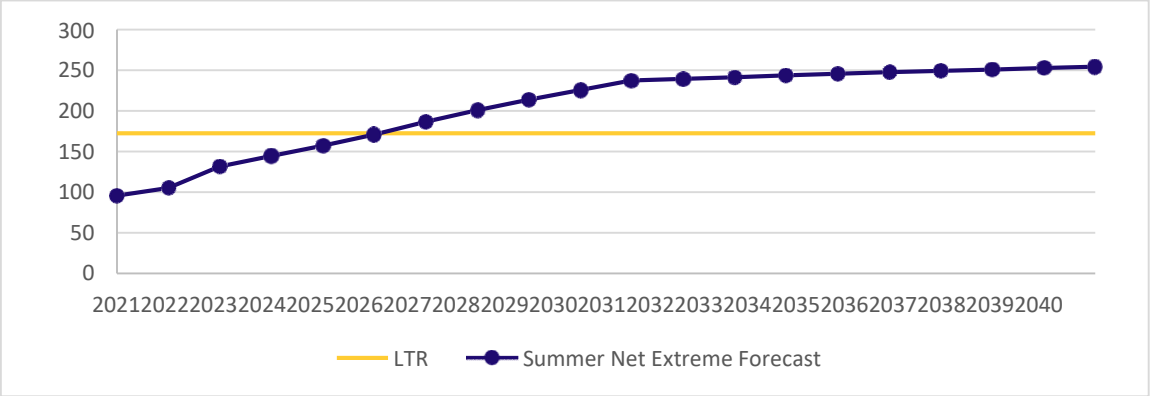


Figure 11| Everett TS Capacity Need

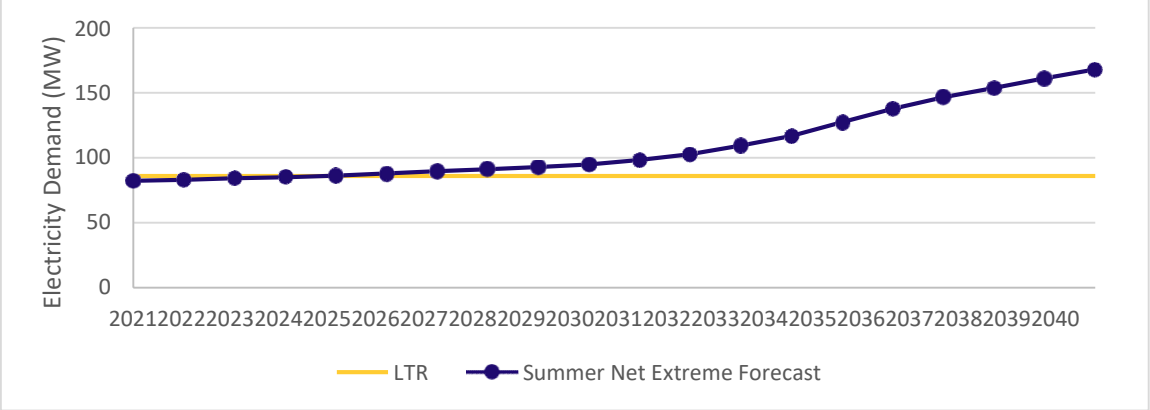
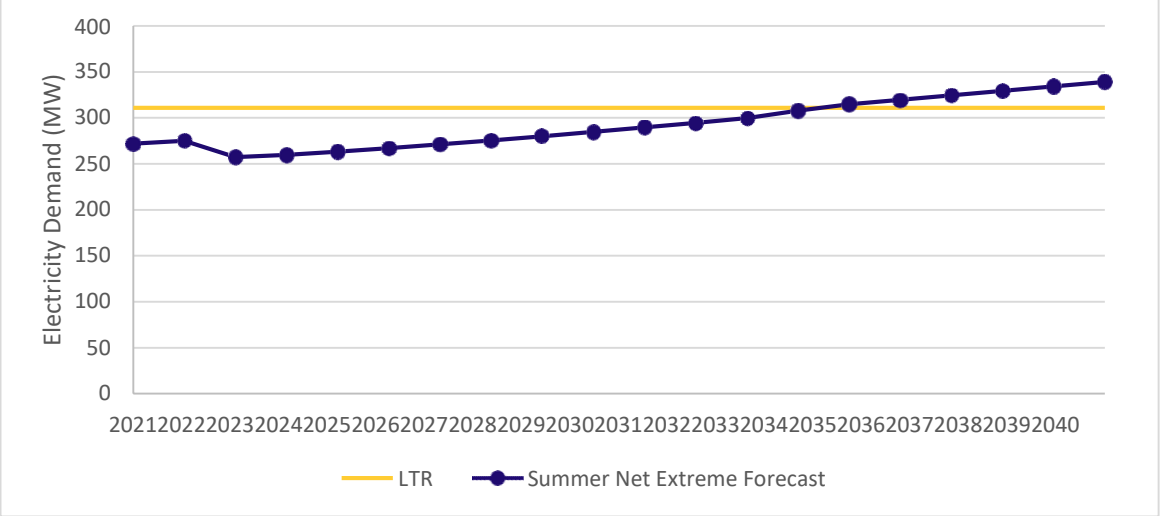


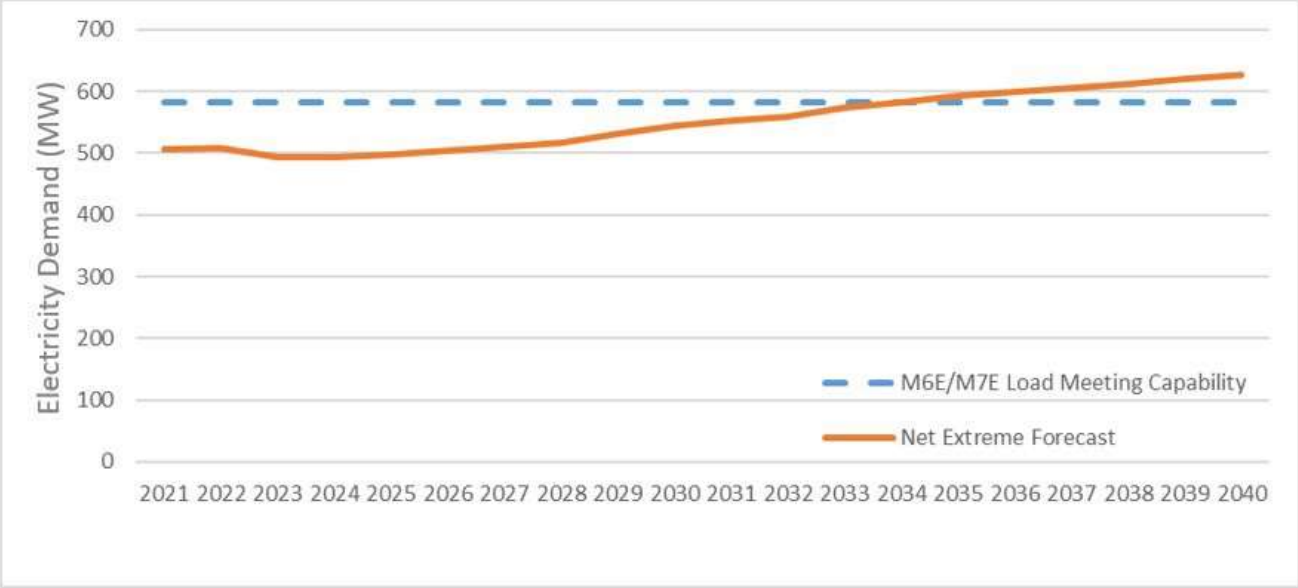
Figure 12| Midhurst TS Capacity Need



6.2.2 Supply Capacity Needs

The circuits M6E and M7E form a 230 kV double circuit from Essa TS to Minden TS. These circuits provide supply to Midhurst, Orillia, Bracebridge and Muskoka. The section between Essa TS to Midhurst TS belongs to the Barrie/Innisfil sub-region. This need occurs for section Essa TS to Midhurst TS. The M6E section between Essa TS to Midhurst TS (10.3 km) will exceed its LTE for loss of M7E or for an Essa HL7 or Essa L7L20 breaker failure starting in 2034. This need is worsened with local generation out of service. Also, the M6E section between Essa TS to Midhurst TS will exceed its LTE with M7E out of service pre-contingency and a contingency to D1M, D3M or D4M. The need is illustrated in Figure 13 below. Note that in the higher demand scenario, this need is advanced by two years.

Figure 13| M6E/M7E Supply Capacity Needs



6.2.3 End-of-Life Refurbishment Needs

Sections of circuits E8V/E9V are reaching end-of-life and need replacement. Information provided by Hydro One Transmission indicated that the in-service date will be 2027 to refurbish 56 km of 230 kV transmission line from Orangeville TS to Essa TS. With no criteria violations identified as part of system studies, there are no needs from a regional perspective that should be coordinated with Hydro One's sustainment plans for a section of circuits E8V/E9V.

6.2.4 Load Security and Restoration Needs

There are no load security or restoration needs identified in the planning time frame.

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the system needs in the Barrie/Innisfil sub-region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing load meeting capability. These are commonly referred to as "non-wires" alternatives (NWA) and can include things like local utility scale generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need.

The screening process resulted in NWA being considered for all of the near/medium-term needs to be addressed by the IRRP, except the end-of-life needs. A like-for-like sustainment plan is appropriate for the end-of-life needs given that the system studies did not identify any regional needs related to these assets. Needs characterization was completed for the Barrie TS and Everett TS station capacity needs. While the supply capacity need arising on the M6E/M7E circuits is in the longer-term, needs characterization was completed for this need to inform future options.

7.1 Options and Recommendations for Meeting Near/Medium-Term Needs

The Barrie/Innisfil IRRP will make recommendations to address near/mid-term timeframe needs. An options analysis, including NWA where feasible, has been conducted for these needs.

Barrie TS Station Capacity Need

Barrie TS currently serves two LDCs, Alectra Utilities and Hydro One Distribution with InnPower Corporation as an embedded customer. There are six 44 kV feeders serving Alectra Utilities and two 44 kV feeders serving InnPower Corporation. InnPower Corporation originally had one feeder but the first Barrie/Innisfil IRRP recommended an additional feeder due to the continued development of data centres in the city of Barrie and forecast growth in the Town of Innisfil. Demand growth continues to increase in the Innisfil area with InnPower's demand forecasted to reach 113 MW by 2029 which is more than the supply capability of the two feeders. Also, the overall demand forecast for Barrie TS will reach its 10-day LTR in 2027.

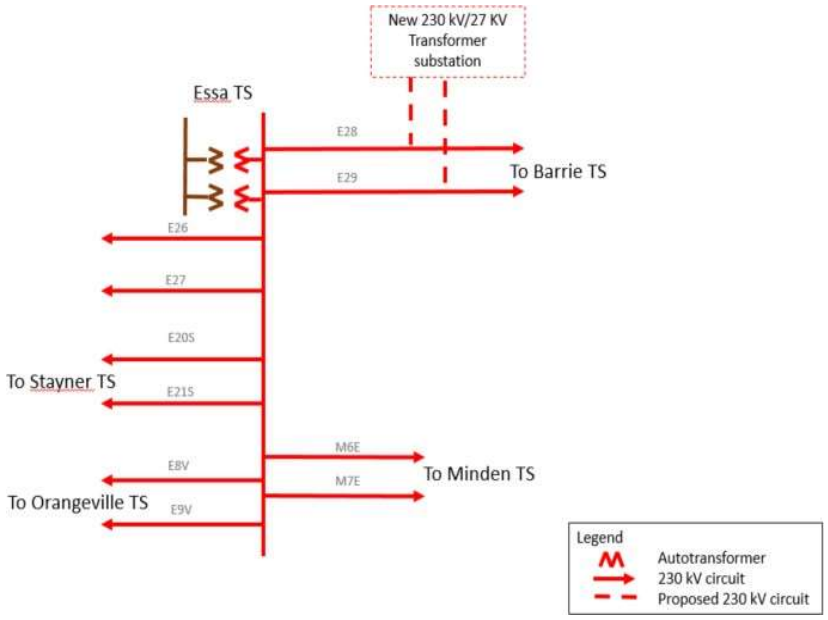
A variety of wires options are considered to address the increased demand growth served by Barrie TS and the supply capacity constraint at the 44 kV feeder level. These wires options are formulated from the detailed options analysis conducted after the Needs Assessment between the transmitter and the LDCs[6]. The following three options were explored and screened out on the basis that they do not fully meet the needs:

- InnPower to connect to existing Alectra feeder as an embedded customer. This requires InnPower to build a distribution tap to the closest Alectra owned feeder. However, there is no available feeder capacity.
- Additional 44 kV feeder position from Barrie TS at a cost of $20M. This solution would provide up to 25 MW of supply capacity which would help the need until 2027. Another solution would still need to be implemented to meet the needs beyond 2027 which would be at an additional cost.
- Load the existing 44 kV supply feeders beyond normal capacity. This alternative would increase each feeder supply capacity by 10 MW per feeder for a total of 20 MW at a cost of $8M. Again, this alternative would help delay the capacity need until 2027 and another solution would have to be implemented beyond 2027.

The wires alternative that is capable of meeting the need includes providing a 230 kV tap connection to the new 230 kV circuits E28/E29 (that will be available post BATU) for a new 230/27.6 kV transformer substation to service the InnPower demand growth. An existing Hydro One Transmission right-of-way (ROW) can be used for this and the length of the tap connection is between 7 to 10 km depending on the location of the transformer substation. This alternative would provide the supply capacity needed beyond the study period and would provide enough capacity for future demand growth in the area. For these reasons, the new transformer substation is chosen as the wires option to be compared against the non-wires alternatives.

[6] Refer to the South Georgian Bay-Muskoka Innisfil Area Supply Alternatives report

Figure 14| Transmission Option for Barrie Station Capacity Need



In terms of non-wires options, the Technical Working Group first reviewed the findings of the Local Achievable Potential Study for the Barrie TS service area that was recommended in the last Barrie/Innisfil IRRP, and subsequently completed between cycles. This study was conducted by Navigant and assessed potential demand-side resources available within the Alectra/InnPower service territories that could defer the need for transmission system investment. The study considered solar PV, CDM and demand response. The forecast technical potential for each non-wires alternative required to meet the need in each year of the forecast was determined and informed the total procurement cost of the non-wires portfolio. The net present value of the costs of the non-wires portfolio was compared to the net present value of the avoided costs associated with the wires solution and it was found that the non-wires portfolio was not cost effective when considering the value streams considered.

As part of the development of this IRRP, the Technical Working Group updated the analysis of non-wires alternatives to ensure it captures the latest information related to option screening, informed by the needs characterization, and option costs. Based on the characteristics of the need, incremental CDM was screened out due to the magnitude of the need as a percentage of the total demand at Barrie TS, and energy storage was considered as it is the least cost of the distributed resource options and serves as a benchmark that can be compared to the wires option.

Table 5 below summarizes the options considered and the net present value of their levelized cost for the Barrie station capacity need arising in 2027 and the supply capacity constraint at the 44 kV feeder level starting in 2025. The new transformer substation is the most cost effective option and the IRRP recommends that the RIP led by Hydro One should further develop and scope this solution.

Table 5 | Options for Barrie TS Station Capacity Needs and Costs

	Option	Cost NPV
Wires	Construct a new 230/27.6 kV transformer substation and connect it to the new 230 kV circuits E28B/E29B available post BATU	$48 M
Non-wires	Construct 81 MW battery storage	$130 M

Everett Station Capacity Need

Everett's near and medium-term needs can be addressed by adjusting the CT ratio of the transformers breakers; the NPV of this option is $ 0.5 M. The estimated costs of non-wires options are orders of magnitude larger and thus screened out from further consideration.

E8V/E9V End-of-Life Needs

When equipment reaches the end of its life and requires replacement, a number of options can be considered.

- Replacement of the equipment with "like-for-like" or closest available standard
- Reconfiguration of existing equipment to "right-size" the replacement option based on:
    - Demand forecast
    - Changes to the use of the equipment since it was originally installed
    - Reliability or other system benefits that an alternate configuration may provide
- Retirement of equipment, considering the impact on load supply and reliability

Since no violations were identified for sections of circuits E8V/E9V in system studies, a like-for-like replacement with the closest available standard is appropriate and can best address the end-of-life needs.

7.2 Options and Recommendations for Meeting Longer-Term Needs

A number of alternatives are possible to meet the region's longer-term needs. While specific solutions do not need to be committed to today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

Additionally, the Technical Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the demand forecast, it may be necessary to initiate the next iteration of the regional planning process earlier.

7.2.1 Midhurst and Alliston Station Capacity Needs

Midhurst TS and Alliston TS are expected to have station capacity needs by 2035 and 2037 respectively. Given the timing of the need, no firm recommendation is required at this time. It is advised to monitor the demand growth in the areas and provide enough lead time to capture changes into the next cycle of regional planning where these needs can be revisited.

7.2.2 M6E/M7E circuits Essa x Midhurst System Capacity Need

The IRRP considered a number of options include incremental cost-effective CDM and storage, even though this is a longer-term need. This analysis showed that incremental cost-effective CDM is a potentially well-suited for deferring this need. As such, the Technical Working Group should continue to consider incremental, cost-effective CDM in between cycles and in the next cycle of regional planning in the region.

7.3 Summary of Recommended Actions and Next Steps

Table 6, below, summarizes the specific recommendations that should be implemented to address the electricity supply needs in the Barrie/Innisfil sub-region.

Table 6 | Summary of Barrie/Innisfil IRRP Recommendations

Need Description	Recommendation	Lead Responsibility	Estimated Cost	Timeline
Everett TS to reach its summer 10-day LTR	Adjust the CT ratio of transformer breakers	Hydro One	~0.5M	2025
Barrie TS to reach its summer 10-day LTR and supply capacity constraint at 44 kV feeder level	Construct a new 230/27.6 kV transformer substation and connecting to the new 230 kV E28B/E29B post BATU	Hydro One and InnPower	~48M	2025
Sections of E8V/E9V circuits to reach end-of-life	Like-for-like replacement	Hydro One		2027

Need Description	Recommendation	Lead Responsibility	Estimated Cost	Timeline
M6E/M7E (Essa TS x Midhurst TS) supply capacity	Monitor demand growth in the area; consider CDM option in next cycle of regional planning as a means of deferring transmission upgrade	Technical Working Group		2034
Midhurst TS to reach its summer 10-day LTR	Monitor demand growth to ensure load supplying capability is maintained; consider in the next cycle of regional planning	Technical Working Group		2035
Alliston TS to reach its summer 10-day LTR	Monitor demand growth to ensure load supplying capability is maintained; consider in the next cycle of regional planning	Technical Working Group		2037
Essa TS Bulk System Supply	Will further be studied as part of Essa Bulk Study	IESO		Today

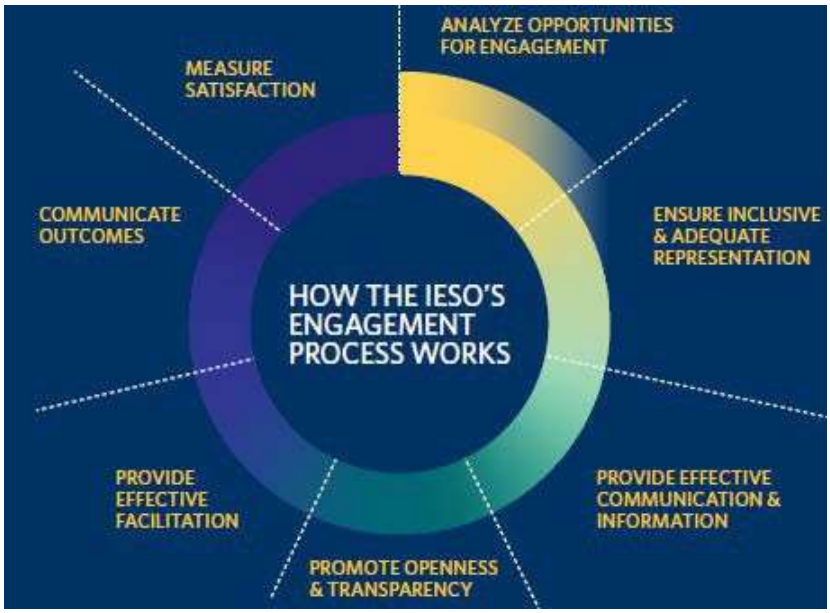
8. Engagement and Consultation

Engagement and consultation are critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Barrie/Innisfil IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 15 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Barrie/Innisfil

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

- Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle;

- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email and through the IESO weekly Bulletin;
- Public webinars;
- Targeted individual and small group meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this new round of planning and establish new relationships with communities and stakeholders in the region.

An invitation was sent to targeted municipalities, Indigenous communities and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the draft South Georgian Bay/Muskoka Scoping Assessment Outcome Greater before it was finalized. Feedback received encouraged the IESO to consider renewable technologies to help reduce local demand.

Following a written comment window, the final Scoping Assessment Outcome Report was published in November 2020 that identified the need for a coordinated planning approach done through two sub-regional Integrated Regional Resource Plans (IRRP): Barrie/Innisfil and Parry Sound/Muskoka.

Following these initial discussions and finalization of the Scoping Assessment, the launch of a broader engagement initiative followed with an invitation to subscribers of the South Georgian Bay/Muskoka region, Indigenous communities and municipalities within boundaries of the sub-region to ensure that all interested parties were made aware of this opportunity for input.

Three public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. The webinars received cross-representation of stakeholders and community representatives attending the webinar and submitting written feedback during a 21-day comment period.

The three stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.

2. The defined electricity needs for the region and potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

All interested parties were kept informed throughout this engagement initiative via email to South Georgian Bay/Muskoka region subscribers, municipalities and Indigenous communities as well as the members of the GTA/Central Regional Electricity Network.

Based on the discussions both through the Barrie/Innisfil IRRP outreach activities and broader network dialogue, there appears to be significant community growth planned and broad interest in electrification, net-zero development, and decarbonisation of electricity supply. To that end, ongoing discussions will continue through the IESO's GTA Central Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the dedicated regional planning engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on local planning and development activities as well as strategic initiative related to electricity to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, other opportunities for broader community engagement. These meetings helped to inform the municipal/community electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made throughout the development of the plan to Indigenous communities in or near the Southern Huron-Perth electricity planning sub-region or those that may have interests in the sub-region. This includes the First Nation communities of Beausoleil, Chippewas of Georgina Island, Chippewas of Rama, Henvey Inlet, Huron Wendat, Magnetawan, Moose Deer Point, Shawanaga, Wahta Mohawks and Wasauksing, as well as the Métis Nation of Ontario communities of Barrie South-Simcoe Métis Council, Georgian Bay Métis Council and Moon River Métis Council.

9. Conclusion

This report documents an IRRP that has been developed for the Barrie/Innisfil sub-region and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. The IRRP makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs. To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring demand growth and efficiency achievements. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the near term, the IRRP recommends the construction of a new transformer substation in or near Innisfil adjusting the CT ratio of transformer breakers at Everett TS, and replacing the E8V/E9V end-of-life with like-for-like. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group monitor growth for Alliston and Midhurst stations to determine when further reinforcements will be needed. The IRRP also recommends to monitor the demand growth in the area served by the M6E/M7E circuits including Midhurst and to consider incremental cost-effective CDM to defer this need in the next cycle of regional planning given the suitability of this option observed as part of this IRRP. The IESO and the Technical Working Group will also continue to monitor community energy planning and monitor electrification trends.

The Technical Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

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Barrie/Innisfil Integrated Regional Resource Plan

Appendices June 2022

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The IESO recognizes the need for, and value of, transparency related to planning data underpinning the development of the Barrie/Innisfil IRRP. In addition to the data provided in these appendices in tabular form, the IESO has published the data in excel format on its website1.

[1] This file can be accessed in the link: https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Barrie-Innisfil

Appendix A. Overview of the Regional Planning Process

A.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium and long term time frame and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board (OEB) convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. [2] The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a Scoping Assessment to determine what type of planning is required for a region. A Scoping Assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused Regional Infrastructure Plan ("RIP") can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference.

[2] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

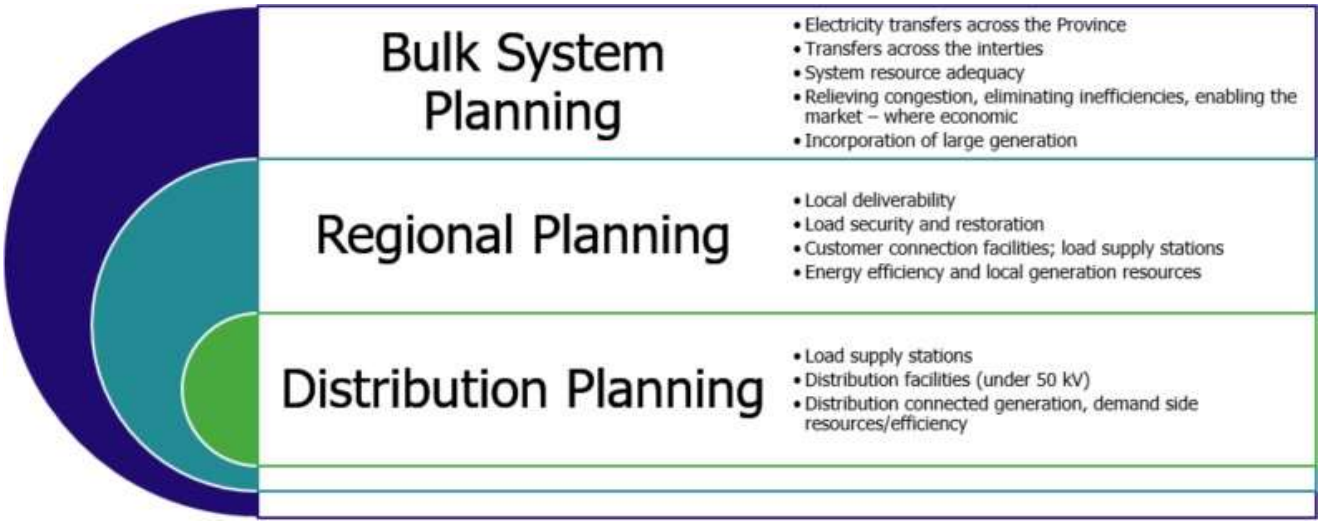
The final Needs Assessment Report, Scoping Assessment Outcome Report, IRRP and RIP are posted on the IESO's and the relevant transmitter's web sites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure 1, three levels of electricity system planning are carried out in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. Distribution planning, which is carried out by local distribution companies ("LDCs"), considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

Figure 1 | Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Appendix B. Demand Forecast

This Appendix describes the methodologies used to develop the demand forecast (peak and duration) for the Barrie/Innisfil sub-region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participating LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the method used by the IESO to determine the forecast starting point, the approaches and methods used by each LDC to forecast demand in their respective service area, the conservation and DG assumptions and the duration forecast methodology.

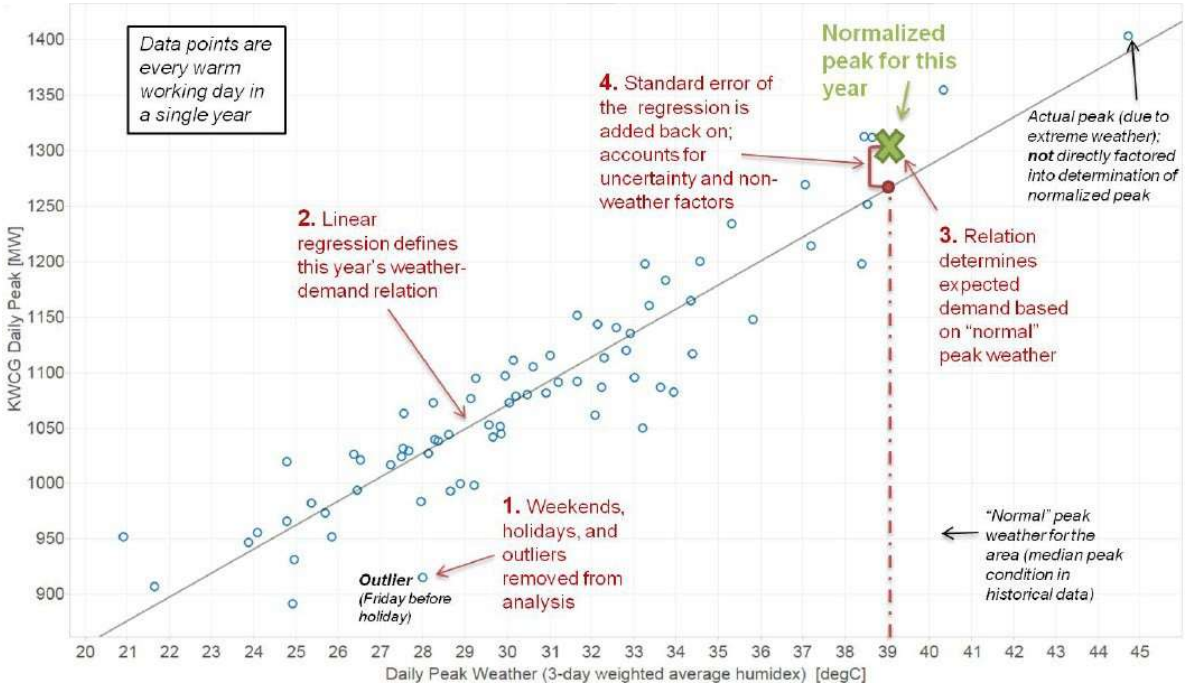
B.1 Method for Determining Forecast Starting Point

To develop a standardized starting point for the Barrie/Innisfil sub-region demand forecast, the following steps were performed:

- 5-year i.e., 2015-2020, historical coincident peak demand data was gathered for each station
- Historical demand data was weather normalized to reflect median peak weather conditions at each station
- Historical output from Distributed Generation at the time of peak was added back to the historical demand for each year (because DG output is subtracted from the gross forecast)
- The starting point is typically selected using the most recent weather-corrected gross peak load; previous year's data points are used to observe trends and outliers

In order to weather-normalize the data, historical demand was adjusted to reflect the median peak weather conditions for each transformer station in the area for all historical years. Median peak refers to the expected peak demand under the most likely, or 50th percentile, weather conditions. This means that in any given year there is an estimated 50% chance that the actual peak demand will exceed this peak, and a 50% chance that the actual peak demand will be lower than this peak. The methodological steps are described in Figure 2; note that this is an illustrative example that was developed for a different region.

Figure 2 | Method for Determining the Weather-Normalized Peak



The impact of Distributed Generation was then added to the median weather peak for all historical years and the most recent year (2020) was used as a starting point, for each LDC station. This data was provided to the LDCs to inform the starting point of their 20-year demand forecasts, which were developed using their methodology (described in Appendix B.2, below).

Once the LDC 20-year, median peak demand forecasts were provided to the IESO, the forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the reliability of the electric power system generally require the use of extreme weather demand forecasts, or, expected demand under the hottest weather conditions (in the case of Barrie/Innisfil sub-region, which is a summer peaking region) that can be reasonably expected to occur. Peaks that occur during extreme weather are generally when the electricity system infrastructure is most stressed. The extreme weather adjustment factors used in the Barrie/Innisfil IRRP were calculated as per IESO's methodology for modelling extreme weather conditions, which determines the relationship between weather and demand for a given region in a given timeframe.

B.2 LDC Forecast Methodologies

This section describes the methodologies used by the participating LDCs to develop their planning forecasts. These include:

- Alectra Utilities Inc.
- Hydro One Networks Distribution
- InnPower Corporation

B.2.1 Alectra Utilities Inc.

The Alectra Utilities long-term load forecast provides an indication as to where and how much the load increases are occurring. Alectra Utilities performs a load forecasting exercise annually.

Alectra Utilities performed a combination of two methods of forecasting to determine the long-term system capacity adequacy assessment:

- End-use analysis using the latest information available from municipal report; and
- Past system peak performance and trend (statistical) analysis

End-Use Analysis Using the Latest Information

Alectra Utilities reviewed economic development and outlook for different regions that include Ontario Government development, population growth and job growth projections, municipal economic analysis report, past housing completion statistics and future housing projection, Industrial, Commercial, Institutional (ICI) activities and news from media.

- **Population Growth**: Historical annual population growth was obtained from Regional Annual Economic and Municipal Development Review Reports. Long-term annual population projections were obtained from provincial and municipal official plan reports published by the Ontario government, and regional/municipal governments.
- **Employment Growth**: Historical employment and economic growth statistics reports published by Provincial and Municipal governments were used to extract the historic economic development and growth rates. Employment growth and structure projections were used to develop the long-term employment forecast categorized by the sector, industry and service types.
- **Housing Activities**: The number and mix of housing completions, vacancy rates and building permit activities in the Region/Municipal boundaries, and residential developments plan were reviewed. Plans of subdivisions and condominiums were obtained and analyzed to develop the long-term load forecast.
- **ICI Building Activity**: Industrial and Commercial development rate, commercial vacancy rate, industrial sale prices per square feet, total ICI construction and commercial/industrial building permits were obtained and compiled to develop the long-term load forecast.

Weather Correction

Alectra used weighted 3-day moving average temperature to correlate the peak demand and weather. Peak demand weather normalization is the process for estimating what peak demand would have occurred in a given time period if the weather had been normal (1 in 2). The weather normalized peak demand was used as the starting point for the forecast. Alectra used "1- in – 10" (extreme) weather (i.e., high temperatures) on peak demand[3].

[3] The 1 in 2 forecast was used to develop the gross IRRP median weather forecast. This was subsequently adjusted for extreme weather according to the methodology in Appendix B.1.

Other Factors

The other contributing factors to long-term load projections were CDM contribution and other government incentives and programs (i.e., Global Adjustment), emerging industrial technologies (i.e., Microgrid, battery storage, combined heat & power, etc.), newly introduced load types (i.e., electric vehicles, fleets) that were reviewed and assessed in load forecast procedure.

CDM

Alectra Utilities' load forecast was performed using current year's peak (weather normalized) as starting point. The impact of CDM programs in the previous years is reflected in the actual peak. The CDM for future years was considered in the forecast[4]

DG

Alectra Utilities' forecast considered the existing DG and DG connections forecasted over the horizon period.

Electrification of Transportation

Alectra Utilities continues to monitor the uptake of electric vehicles and projects related to electrification of transportation to better understand and determine the impact on local electricity needs. Alectra Utilities used the available information on EV adoption and evaluates the impact of the EVs at the peak.

Past System Peak Performance and Trend Analysis

The trend analysis was performed to forecast the system peak from historical peak demand results. The purpose of the trend analysis is to compare the results with end-use method to obtain more realistic long-term load projections considering the historical demand peak.

Conclusion

There is a level of uncertainty with respect to any forecasting exercise. Any major unexpected changes to assumptions, economic pressure or crisis events, government directives and other social/economic/political events that can impose changes and that were not contemplated at the time of forecasting will be reviewed and the forecast will be adjusted annually accordingly to reflect the changes.

B.2.2 Hydro One Networks Distribution.

Hydro One Distribution services the areas of South Georgian Bay Muskoka region that are not serviced by other LDCs. It supplies power through various stations included in the study area.

[4] Note that, while the impact of existing/past CDM programs were included in the starting point, future CDM program impact was forecasted by the IESO

Hydro One Distribution used both econometric and end-use forecasting to develop the 20-year load forecast provided to the IESO. A baseline forecast (MW station peak in the base year) was developed, taking into account such factors as normal operating conditions, coincident peak loading, and extreme weather conditions.

For the Barrie/Innisfil IRRP forecast, Hydro One Distribution used the weather corrected peak demand levels for the stations serving Hydro One customers. From the established baseline year, a growth rate (%) was applied to station demand levels to provide forecast values, at each station, within the study frame.

Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW/sq.ft); and electrification trends (e.g., more vehicles switching from gas to electrical vehicles).

Where possible, detailed information about load growth, based on local knowledge and or municipal/provincial plans, was used to augment the forecast values within the study period.

B.2.3 InnPower Corporation.

As one of the fastest growing electrical utilities in Ontario, InnPower maintains a service territory of 292 square kilometers and provides services to Town of Innisfil and South of Barrie.

InnPower's load forecast methodology was mainly based on the actual load requests received from customers (Developers/ Individuals). This information provided the planning inputs which were categorized in three main sectors of residential, ICI and employment load demand.

The calculated baseline forecast was then adjusted considering factors such as normal operating conditions, coincident peak loading, municipal fact sheet on number of issued building permits, population growth rate in the area and the historical peak load records.

In order to capture the housing market demand, InnPower considered the historical number of energized units in the previous years to regulate the long-term forecast on the annual basis. Also, from 2021, demand for electrical vehicles was added to the load forecast as a new factor impacting the peak demand and required capacity.

Winter peak forecasting was projected based on the historical data in comparison to the summer peak, given the fact that peak load trend for InnPower is in summer.

B.3 Conservation Assumptions in Barrie/Innisfil Forecast

Conservation & Demand Management (CDM) measures can reduce the electricity demand and its impact can be separated into the two main categories: Building Codes & Equipment Standards, and Energy Efficiency Programs. The assumptions used for the Barrie/Innisfil IRRP forecast are consistent with the CDM assumptions in the IESO's 2020 Annual Planning Outlook (APO), which was the latest provincial planning product when the demand forecast for this IRRP was developed. A top down approach was used to estimate peak demand savings from provincial level to the Essa transmission zone and then allocated to the Barrie/Innisfil sub-region. This section describes the process and methodology used to estimate CDM savings for the Barrie/Innisfil sub-region and provides more detail on how the estimated savings were developed.

B.3.1 Estimate Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the Essa zone and compared with the gross peak demand forecast for the zones separately. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region.

Consistent with the gross demand forecast, 2020 was used as the base year. New peak demand savings from codes and standards were estimated from 2021 to 2040. The sectoral annual peak reduction percentages of each year were applied to the demand that was forecasted at each station in order to develop an estimate of the peak demand impacts from codes and standards as well as energy efficiency programs. The forecasted savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

B.3.2 Estimate Savings from Conservation Programs

In addition to codes and standards, the delivery of energy efficiency programs reduces electricity demand. The impact of existing and committed energy efficiency programs were analyzed, which include the 2021 – 2024 CDM Framework and other provincial and federal EE programs. A top down approach was used to estimate the peak demand reduction due to the delivery of EE programs, from provincial to Essa zone to the stations in the region. Persistence of the peak demand savings from energy efficiency programs was also considered over the forecast period.

B.3.3 Total Conservation Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector. Summer peak demand savings by TS were summarized in Table 1. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings, along with the impact of distributed generation resources, were applied to gross demand to determine net peak demand for further planning analyses.

Table 1 | Forecast of Expected Summer Peak Demand Savings (MW) Due to Codes and Standards and Funded CDM Programs - by Station

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Alliston TS	1.3	2.6	3.9	5.4	6.2	6.7	7.3	7.8	8.2	8.4	8.4	8.5	8.5	8.5	8.5	8.5	8.7	8.8	8.9	9.0
Barrie TS	0.8	1.7	3.2	4.8	6.0	6.9	8.0	8.9	9.7	10.5	10.8	10.9	10.8	10.7	10.6	10.6	10.7	10.8	10.9	10.9
Everett TS	0.9	1.8	2.6	3.6	4.2	4.5	4.9	5.2	5.4	5.6	5.7	6.0	6.2	6.5	7.0	7.5	8.0	8.4	8.8	9.2
Midhurst TS	2.9	5.7	8.0	10.9	12.7	13.6	14.7	15.4	16.1	16.7	16.7	16.9	16.9	16.9	16.9	17.1	17.4	17.6	17.9	18.2

B.4 Distributed Energy Resources Assumptions

Besides conservation savings, the expected peak contribution of existing and contracted DG in the area were also taken into account.

Table 2 | DG Forecast by Station

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Alliston TS	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.21	0.04	0.03	0.03	0.00	0.00	0.0
Barrie TS	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.22	0.17	0.10	0.10	0.06	0.06	0.06	0.00	0.00	0.0
Everett TS	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.27	0.26	0.20	0.20	0.16	0.16	0.07	0.00	0.00	0.0
Midhurst TS	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.02	4.93	1.85	0.18	0.04	0.02	0.00	0.00	0.00

DG capacity factors were applied using factors from the Reliability Outlook (RO) and the APO.

- Solar capacity contribution: Summer Average 13.8% - Winter Average 0%
- Wind capacity contribution: Summer Average 13.7% - Winter 37.8%
- Hydro Capacity contribution: Summer Average 86.2% - Winter 81.6%

B.5 Planning Forecast by Station

After taking the median weather forecast provided by LDCs and applying the CDM assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided below:

Table 3 | Summer Peak Demand Forecast (MW) by Station

Transformer Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Alliston TS	132.6	136.1	139.1	140.6	142.3	146.4	149.9	153.9	157.0	159.5	160.9	163.5	166.2	168.9	171.7	174.2	176.8	179.3	181.8	184.3
Barrie TS	95.7	105.3	131.6	144.4	157.2	171.1	186.6	200.9	213.9	225.7	237.6	239.5	241.7	243.7	245.9	247.6	249.3	251.1	252.8	254.5
Everett TS	82.1	83.1	84.2	85.0	86.2	87.8	89.4	91.1	92.9	94.8	98.1	102.5	109.1	116.6	127.3	137.4	146.6	153.7	160.8	167.9
Midhurst TS	271.9	275.0	257.5	259.7	263.2	267.2	271.1	275.5	280.0	284.7	289.5	294.4	299.6	307.9	314.9	319.7	324.4	329.3	334.2	339.1

B.6 Duration Forecast Methodology

B.6.1 General Methodology

A load duration forecast consists of a series of year long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are studied to determine the feasibility of using non-wires alternatives to address needs in the region, and to determine which type of non-wires alternatives may be best suited to meet the needs.

Hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five years' worth of historical hourly load data. Firstly, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused by load transfers, outages, or infrastructure changes).

Subsequent to the removal of outliers, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station's hourly load profile. For the Barrie/Innisfil sub-region, the following predictor variables were used:

- Calendar factors (such as holidays and days of the week)
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled)
- Demographic factors (population data[5])
- Economic factors (employment data[6])

Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 10 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 10 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 150 possible hourly load forecasts for each future year being forecast. For example:

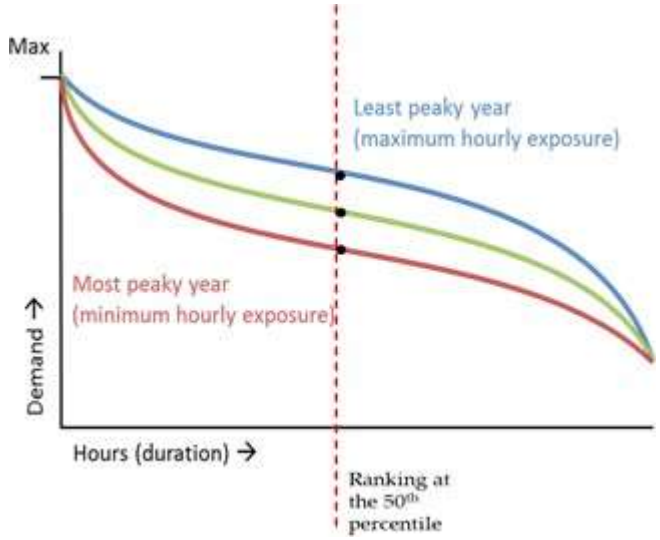
- 10 years of historical weather data ×15 weather sequence shifts =150 weather scenarios for each year being forecast
- E.g., June 2nd 2025 was forecasted assuming the historical weather from every May 26th to June 9th that occurred between 2011 and 2020.

Subsequently, the list of 150 forecasts were ranked in ascending order based on their median values. Load duration curves which illustrate this ranking can be seen in Figure 3.

[5] Sourced from the Ministry of Finance and Statistics Canada

[6] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

Figure 3 | Example of Ranking Load Duration Curves Created from Hourly Load Profiles



The forecast in the 3rd percentile was chosen as the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve).

The yearly forecasts were scaled to their respective maximums from the peak demand forecast, and added together to form a single multi-year forecast.

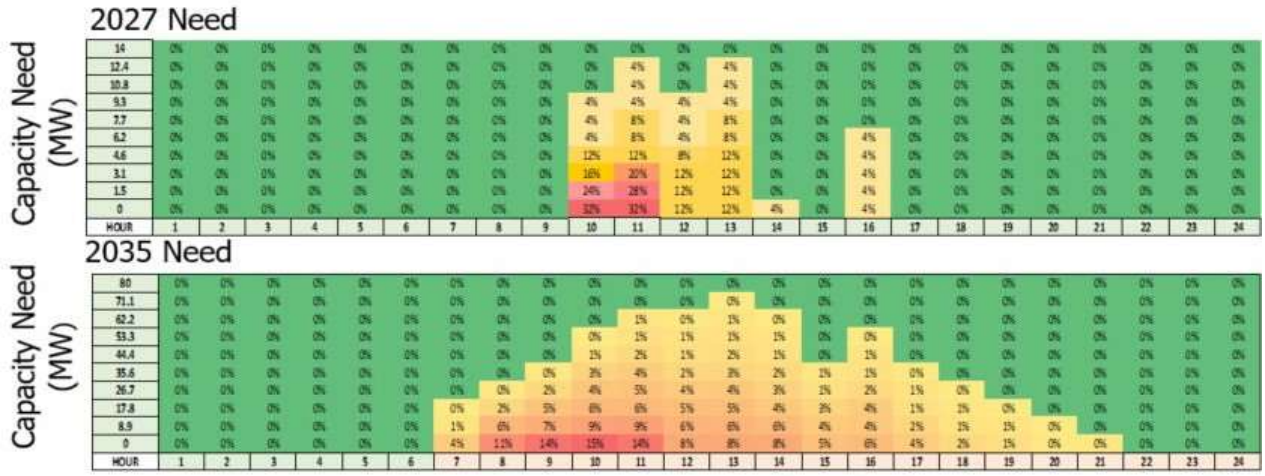
B.6.2 Hourly Need Characterization

Barrie TS Capacity Need

Table 4 | Barrie Capacity Need Key Metrics

Key Metrics	2027	2035
Limit (MW)	172.8	172.8
Capacity Need (MW)	13.8	73
Number of Events	8	146
Maximum Energy Per Event (MWh)	53.15	565.1
Maximum Event Length (Hours)	6	15
Average Event Length (Hours)	2.8	5.7
Total Energy (MWh)	118.5	15,379

Figure 4 | Barrie TS Capacity Need Daily Heat Map (% of Need Hours at or Above MW value)

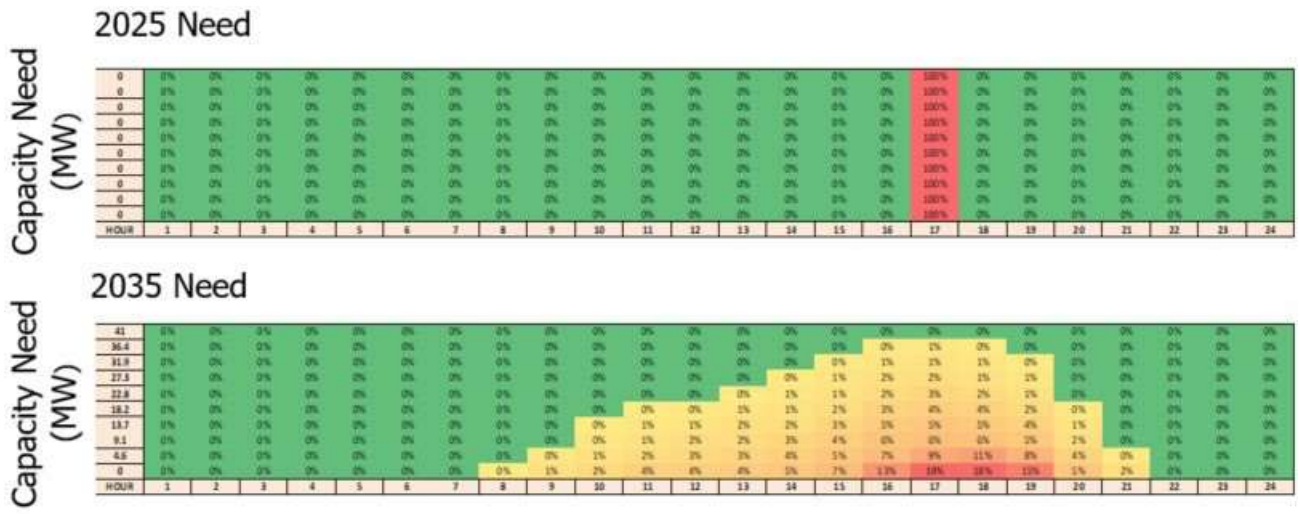


Everett TS Capacity Need

Table 5 | Everett Capacity Need Key Metrics

Key Metrics	2027	2035
Limit (MW)	86	86
Capacity Need (MW)	0.2	41.25
Number of Events	1	221
Maximum Energy Per Event (MWh)	0.2	320.2
Maximum Event Length (Hours)	1	14
Average Event Length (Hours)	1	4.6
Total Energy (MWh)	0.2	9,935.4

Figure 5 | Everett TS Capacity Need Daily Heat Map (% of Need Hours at or Above MW value)

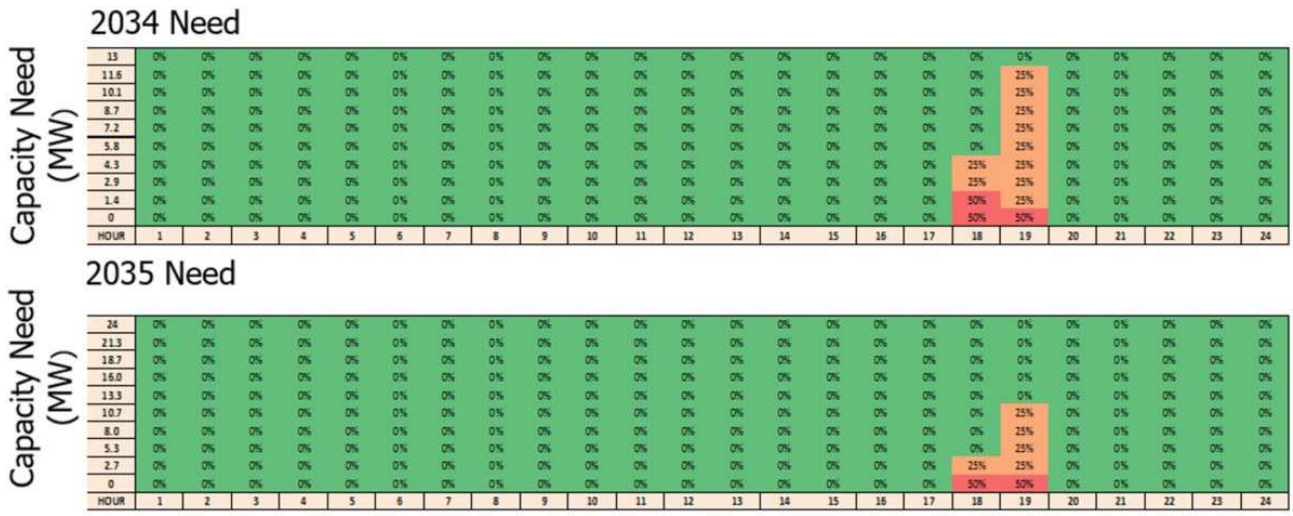


MxE System Capacity Need

Table 6 | MxE System Capacity Need Key Metrics

Key Metrics	2034	2035
Limit (MW)	581	581
Capacity Need (MW)	12.8	23.87
Number of Events	5	8
Maximum Energy Per Event (MWh)	20.5	47.1
Maximum Event Length (Hours)	2	3
Average Event Length (Hours)	1.6	2.1
Total Energy (MWh)	53.9	161.6

Figure 6 | MxE Capacity Need Daily Heat Map (% of Need Hours at or Above MW value)



Appendix C. Options and Assumptions

C.1 Economic Assumptions

An economic analysis was performed in order to compare the relative net present value ("NPV") of the feasible IRRP alternatives, including the lowest cost generation option that could meet the characteristics of the need and transmission options. The relative performance of the option (or combination of options) NPVs informs the identification of the most cost-effective options for meeting the region's needs.

The following is a list of the assumptions made in the economic analysis:

- The NPV of the cash flows is expressed in 2021 CAD.
- The USD/CAD exchange rate was assumed to be 0.78 for the study period.
- The NPV analysis was conducted using a 4% real social discount rate. Sensitivities at 2% and 8% were performed. An annual inflation rate of 2% is assumed.
- The life of the station upgrades was assumed to be 45 years; and the life of the storage assets was assumed to be 30 years and 10 years respectively. The life of the storage asset was based 3600 cycles, which is assumed to be used to serve the local need first, and then global energy and ancillary services for the rest of the year. Cost of asset replacement were included where necessary to ensure the same NPV study period.
- Development timelines for generation and storage were assumed to be 3 years.
- An energy storage facility was identified as a low-cost resource alternative. Total energy storage system costs are composed of capacity and energy costs (I.e. energy storage devices are constrained by their energy reservoir). The estimated overnight cost of capital assumed is about $900-$1600/kW (2021 CAD) depending on the storage capacity to energy requirement, based on escalating Ontario-specific values from a previous study independently conducted for a collection of entities including the IESO.
- The size of the resource option was determined by deterministic capacity assessment.
- Sizing of the storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size is capable of using existing gas resources to sufficiently charge to meet the hours of unserved energy.
- System capacity value was $144k/MW-yr (2021 CAD) based on an estimate for the Cost of the Marginal New Resource (Net CONE), a new SCGT in southwestern Ontario, with a sensitivity of +/- 25% assessed. Note that the IESO's Pathways to Decarbonization Study is exploring different scenarios regarding new capacity to meet provincial resource adequacy needs.

- Production costs were determined based on energy requirements to serve the local reliability need, assuming fixed operating and maintenance costs of $12/kW-yr for storage, variable operating and maintenance costs of $5/MWh and a heat rate of 12 MMBtu/MWh for gas-fired resources.
- Carbon pricing assumptions are based on the proposed Federal carbon price increase, from $50/t in 2022 to $170/t by 2030, and applied to a facility's production. A sensitivity of up to +225% was assessed on the carbon costs for the gas-fired generation option to assess the risk potential policy changes to the current carbon pricing strategy.
- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

C.2 Wires Options for Barrie TS Capacity Need

Table 7 presents the wires options to address the increased demand growth served by Barrie TS and the supply capacity constraint at the 44 kV feeder level. These wires options were formulated from the detailed options analysis conducted after the South Georgian Bay Muskoka Needs Assessment.

Table 7 | Wires Alternative Comparison for Barrie TS Capacity Need

Alternatives	InnPower to connect to existing Alectra feeder as embedded customer	Additional 44 kV feeder position from Barrie TS	Load existing 44 kV supply feeders beyond normal capacity	Provide 230 kV tap connection to Innisfil service territory for new TS
Scope/ Proposal	To utilize spare capacity at Barrie TS, this alternative will require Inn Power to build a distribution tap to the closest Alectra owned feeder and utilize spare capacity (if available). For this to occur, both station capacity and individual feeder capacity must be within limits.	InnPower will be supplied with 2-44 kV feeders from Barrie TS once the BATU project is completed. This alternative seeks to install a 3rd feeder to provide additional supply capacity.	InnPower will be supplied with 244kV feeders from Barrie TS once the BATU project is completed. This alternative will require Hydro One Dx to increase loading these two feeders beyond the normal planning capacity while staying within the overall station capacity offered by BATU. This alternative would increase each feeder supply capacity by 10MW/feeder for a total of 20MW.	This alternative provides increases supply capacity for InnPower by constructing a new 230/27.6kV transformer substation and connecting to the new 230kV transmission lines (E28B/E29B) that will be available post BATU.
Impacted Participants	Alectra InnPower	Hydro One Tx, Dx InnPower	Hydro One Dx InnPower	Hydro One Tx InnPower
Transmission Considerations	OGCC presently utilizes Barrie TS M4 feeder as a backup supply and this supply requirement for Hydro One will remain in place following the completion of the BATU project.	Barrie TS will be built to follow H1 standard 230/44kV Jones arrangement with 8 feeder positions. To accommodate an additional feeder, the existing layout and station footprint will require redesign. Modifications to the low voltage steel structure, access road, relocation of capacitor banks, and fence extension will be required. Note:	No significant transmission considerations.	Provide approximately 7km new 230kV double circuit line tap from E28B/E29B circuits to the new substation.
Distribution Considerations	Alectra M4 feeder provides low exposure backup for OGCC, and its short feeder length and geographic location restricts new load/tap connections. Alectra has indicated the feeder capacity is not available on the remaining feeders closest to InnPower service territory, due to its existing load and anticipated growth.	There are known physical challenges due to clearances adding additional complexity for a new feeder egress. To build a new feeder, an underground egress would be required transitioning to an overhead lines and will follow a similar path to the existing feeders travelling south to Innisfil.	Voltage support will be required along each of the 2-44kV feeders to maintain acceptable voltage profile on the feeders. Further Dx studies (coordinated with InnPower) are needed to determine the location of regulating stations (RS)	Inn Power will construct and own a new 230/27.6 83MVA transformer station.

Alternatives	InnPower to connect to existing Alectra feeder as embedded customer	Additional 44 kV feeder position from Barrie TS	Load existing 44 kV supply feeders beyond normal capacity	Provide 230 kV tap connection to Innisfil service territory for new TS
Implementation Timing	2-3yrs	2-3yrs	2-3yrs	3-5 years
Solution Valid Until	50MW+0MW* =50MW 2025 Note: * capacity is not available at this time.	50MW+25MW=75MW 2027	50MW+20MW=70MW 2027	50MW+ (100MW) >2030
Costs	Costs = Not Applicable. Costs have not been explored as there is no available feeder capacity. Should capacity become available in the future, estimates can be obtained from the working group if practical to do so.	HONI Transmission - $5M HONI Distribution – $15M Total - $20M The cost of a new feeder position will be substantially higher than what would normally be expected for this type of work for both Hydro One and Hydro One Distribution due to the egress challenges outside the station and physical space limitations inside Barrie TS.	HONI Transmission – N/A HONI Distribution - $8M Total - $8M	HONI Transmission - $14M InnPower - $30M Total - $44M
Meets the Need	This solution is only viable if OGCC backup control strategy changes, and feeder capacity on the closest feeders from Alectra becomes available. Any spare capacity that would be available if this alternative proceeds would still fail to meet the full supply needs within the study period, and will need to be combined with alternate solutions.	A new feeder position will provide up to 25MW supply capacity, which will help to delay the need to 2027. Another solution will need to be implemented to meet the full capacity needs beyond 2027 which would be at additional cost to this alternative or to replace this alternative. This alternative is not viable as a standalone option and still must be combined with options 4 to meet supply needs within the study period.	This alternative will provide up to 20MW increased supply capacity which will help to delay a capacity need until 2027. Another solution will need to be implemented to meet the full capacity needs beyond 2027 which would be at additional cost to this alternative or to replace this alternative. This alternative is not viable as a standalone option and still must be combined with option 4 to meet supply needs within the study period.	This alternative will provide the supply capacity needed well beyond the study period. The station is presently being sized with 83MVA transformers will provide sufficient supply capacity for area load growth and this alternative can be utilized as standalone solution to meet the needs without additional interim investments.

Appendix D. Planning Study Results

D.1. Introduction

This document provides the scope of the technical study for both the Parry Sound/Muskoka and Barrie/Innisfil Integrated Regional Resource Plans (IRRPs). Both sub-regions form part of the larger South Georgian Bay/Muskoka (SGBM) region.

D.1.1 Area of Study

The area of study encompasses the SGBM region, bounded by Parry Sound Transformer Station (TS) to the north, Minden TS to the east, Everett TS to the south, and Meaford TS to the west. An overview of the SGBM Region can be seen in Figure 1 below. The largest transmission connected generators in the area are Des Joachims GS (430 MW, hydroelectric) to the east and Henvey Inlet Wind (300 MW, wind) to the north.

Figure 1 - Overview of SGBM Region

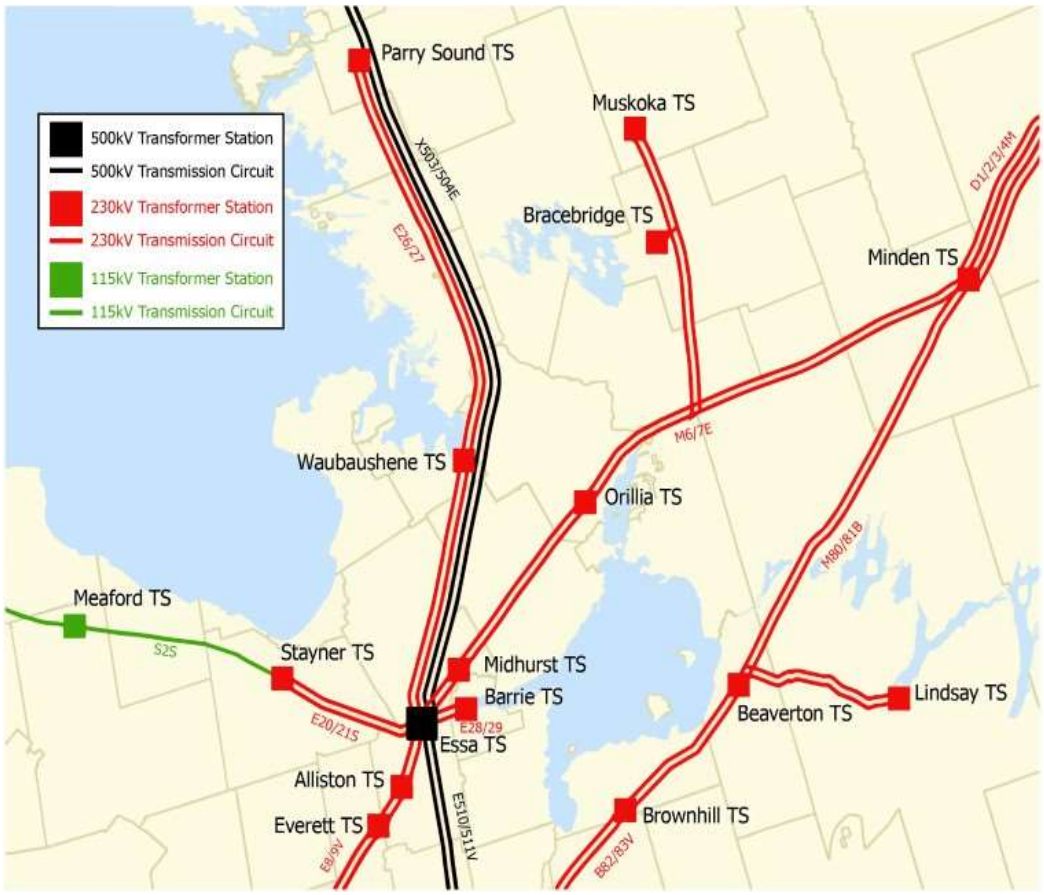
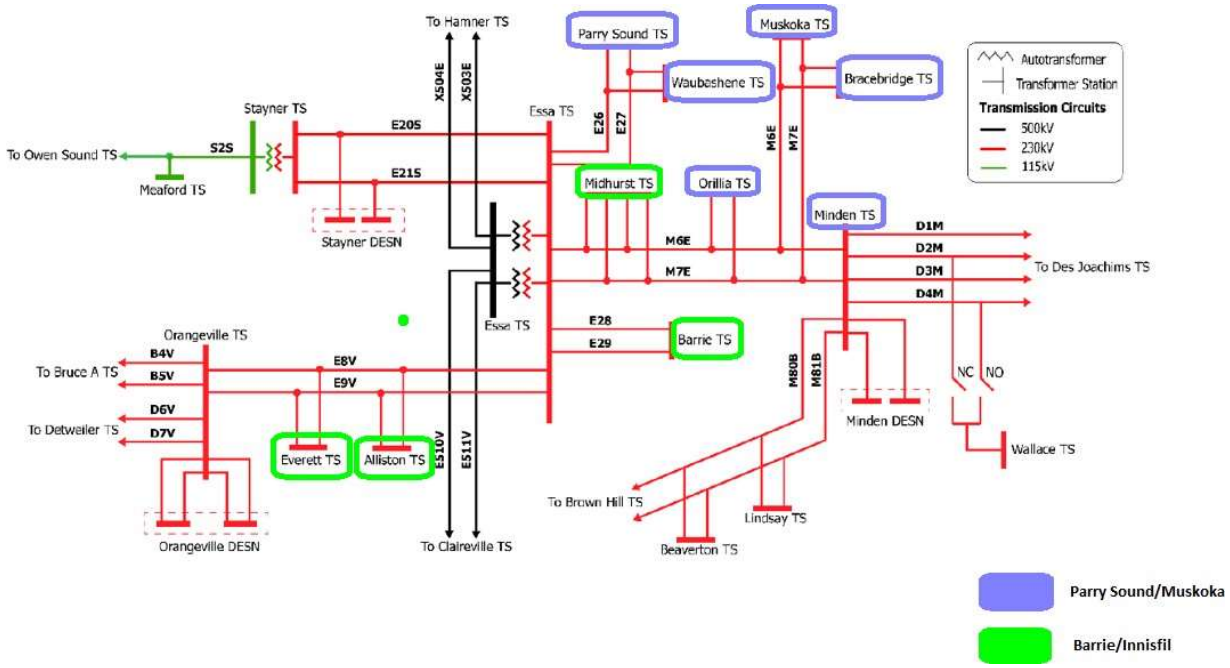


Figure 2 - Electricity Infrastructure in the SGBM Region



The region is currently supplied from 115 kV and 230 kV transmission lines and stations that connect at Essa TS. The 500/230 kV autotransformers at Essa TS provide the major source of supply to the area. As an outcome of the last planning cycle, the 115 kV supply in the region (from Essa TS to Barrie TS) is currently being converted to a 230 kV supply, and will be completed in 2023. An overview of the electrical infrastructure that currently supplies the region is provided in the single line diagram in Figure 2.

D.2. Scenarios Assessed

D.2.1 Summary of Scenarios

This section outlines the scenarios assessed by the technical study. It covers both summer and winter scenarios of the SGBM area.

Table below summarizes the scenarios assessed. Further details on the load forecast, local generation assumption, and interface flows are discussed in the subsequent subsections. Note that all scenarios assume peak summer load conditions consistent with the IRRP forecast.

Table 1 - Summary of Scenarios to be Assessed

Scenario Name	Local Generation	Interface Flows	Contingencies Assessed
Summer A	All I/S[7]	Flow South: 1,296 MW	N-1, N-2, N-1-1
Winter A	All I/S[8]	Flow South: 303 MW	N-1, N-2, N-1-1
Summer B	Des Joachims GS O/S	Flow South: 1,296 MW	N-1, N-2
Winter B	Des Joachims GS O/S	Flow South: 305 MW	N-1, N-2
Summer C	Henvey Wind Inlet GS O/S	Flow South: 1,296 MW	N-1, N-2
Winter C	Henvey Wind Inlet GS O/S	Flow South: 304 MW	N-1, N-2

D.2.2 Load Forecast

The initial need identification study uses net peak summer forecast snapshots in 2022, 2030, and 2040 (end of planning horizon). The coincident station level forecast is provided in Table 2 below.

Where needs were identified, further studies were performed to refine the need and determine the exact load level/year the need occurs in. Coincident forecasts for select groups of stations were also constructed where appropriate such as when assessing a circuit capacity need serving multiple stations.

Where appropriate, hourly load profiles were developed to aid in the evaluation of non-wires alternatives.

[7] This assumes summer capacity factors of 31% and 14% for hydroelectric and wind power, respectively.
[8] This assumes winter capacity factors of 59% and 38% for hydroelectric and wind power, respectively

A load's power factor of 0.9 at the load was used (without consideration for the status of low-tension capacitor banks[9]).

Table 2 – SGBM Area Coincident Summer Demand Forecast

Station Name	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	120.4	141.2	163.2
Barrie TS	81.6	174.9	197.3
Beaverton TS	68.1	70.9	86.0
Bracebridge TS	26.8	27.0	28.6
Everett TS	82.2	93.7	166.0
Lindsay TS	82.5	87.5	102.4
Meaford TS	33.3	34.2	39.1
Midhurst TS	271.4	281.0	334.8
Minden TS	35.7	37	43.5
Muskoka TS	108.2	119.5	131.1
Orangeville TS	139	160.4	189
Orillia TS	102.4	117.2	131.6
Parry Sound TS	41.6	50.3	54.4
Stayner TS	122.6	133.3	160.3
Wallace TS	29.9	30.4	32.0
Waubashene TS	78.7	87.2	104.5

[9] Low tension capacitor banks are often installed for the purpose of transmission system voltage control, and not power factor correction, and so, they are not considered for load power factor issues.

Table 3 – SGBM Area Coincident Winter Demand Forecast

Station Name	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	97.7	116.7	134.7
Barrie TS	68.8	152.7	171.4
Beaverton TS	77.0	80.5	88.1
Bracebridge TS	32.7	33.2	34.9
Everett TS	55.9	63.8	130.8
Lindsay TS	87.7	93.4	101.7
Meaford TS	43.5	44.8	54.4
Midhurst TS	185	192.6	223.6
Minden TS	52.6	54.7	61.7
Muskoka TS	139.2	151.8	160.8
Orangeville TS	119.8	134.9	162.7
Orillia TS	101	116.2	125.3
Parry Sound TS	56.4	65.9	70.7
Stayner TS	132.5	142.5	172.1
Wallace TS	38.0	38.8	40.8
Waubashene TS	77.7	83.4	91.5

D.2.3 Local Generation Assumptions

Generation facilities are tabulated in Table 4. The base case used dependable generation (i.e., unforced capacity or "UCAP") based on Power System Planning's Capacity Tally for hydroelectric power and assumptions from the 2020 Annual Planning Outlook (APO) for wind power. Scenarios with up to four Des Joachims GS units and all of Henvey Inlet Wind out of service were also studied. Distributed-connected generation (DG) was netted out in the load forecast (load modifier) based on summer peak contribution factors consistent with the Reliability Outlook.

Table 4 – Local Dependable Generation Capacity

Facility Name	Installed Capacity	Seasonal Capacity
Des Joachims GS	430 MW	Summer: 133.35 MW Winter: 253.7 MW
Henvey Wind Inlet GS	300 MW	Summer: 42 MW Winter: 114 MW

D.2.4 Major Interface Flows

- The Flow North/Flow South (FN/FS) interface comprises the circuits that connect the Essa Zone and Northeast Zone. This includes the two 500 kV circuits connecting Hanmer TS to Essa TS and one 230 kV circuit connecting Otto Holden TS to Des Joachims TS. The FS interface is defined identically to the FN interface, but the power transfer is measured in the reverse direction. FN transfer capability is important to reliably supply demand in the Northeast and Northwest zones, as well as facilitate exports to Manitoba, Minnesota and Québec; FS transfer capability is important to deliver imports and supply from the Northwest and Northeast Zones to the rest of the province.
- FN and FS transfers can be limited under certain conditions to ensure acceptable voltage and stability performance (e.g., FN can be limiting under low water conditions and sensitive to demand; and FS can be limiting under heavy water conditions). As of the 2020 APO, FN is limited to 1,500 MW while FS is limited to 2,100 MW.

D.3 System Topology

As mentioned in Section 1, the region is currently supplied from 115 kV and 230 kV transmission lines and stations that connect at Essa TS. The 500/230 kV autotransformers at Essa TS provide the major source of supply to the area.

Table 5 and Table 6 below list the monitored circuit sections in the SGBM area for summer and winter seasons, respectively. Note that the 500 kV circuits are not included.

Table 5 - Summer Ratings of Monitored Circuits and Ratings

Circuit Name	From	To	Continuous	LTE	STE
D1M	Des Joachims TS	Minden TS	550	550	550
D2M	Des Joachims TS	Otter Creek JCT	550	550	550
D2M	Otter Creek JCT	Minden TS	550	550	550
D2M	Otter Creek JCT	Wallace JCT	550	550	550
D2M	Wallace JCT	Wallace TS	550	550	550
D3M	Des Joachims TS	Minden TS	550	550	550
D4M	Des Joachims TS	Otter Creek JCT	550	550	550
D4M	Otter Creek JCT	Minden TS	550	550	550
E20S	Essa TS	Stayner TS	840	1090	1210
E21S	Essa TS	Stayner TS	840	1090	1210
E26	Essa TS	Waubaushene JCT	840	1060	1160
E26	Holmur JCT	Parry Sound JCT	840	1090	1400
E26	Holmur JCT	Holmur SS	840	1050	1140
E26	Parry Sound JCT	Parry Sound TS	840	1090	1400
E26	Waubaushene JCT	Waubaushene TS	840	1090	1400
E26	Waubaushene JCT	Holmur JCT	840	1050	1140

Circuit Name	From	To	Continuous	LTE	STE
E27	Essa TS	Waubaushene JCT	840	1090	1250
E27	Holmur JCT	Parry Sound JCT	840	1090	1250
E27	Holmur JCT	Holmur SS	840	1050	1140
E27	Parry Sound JCT	Parry Sound TS	840	1090	1250
E27	Waubaushene JCT	Waubaushene TS	840	1090	1400
E27	Waubaushene JCT	Holmur JCT	840	1090	1250
E28	Allandale TPS JCT	Barrie TS	1160	1530	1830
E28	Allandale TPS JCT	Allandale TPS	550	550	550
E28	Essa TS	Allandale TPS JCT	1160	1530	1830
E29	Allandale TPS JCT	Barrie TS	1160	1530	1830
E29	Allandale TPS JCT	Allandale TPS	550	550	550
E29	Essa TS	Allandale TPS JCT	1160	1530	1830
E8V	Alliston JCT	Everett JCT	840	1090	1400
E8V	Alliston JCT	Alliston TS	840	1090	1400
E8V	Alliston JCT	Alliston JCT	840	1090	1400
E8V	Essa TS	Alliston JCT	840	1090	1400
E8V	Everett JCT	Orangeville TS	840	1040	1130
E8V	Everett JCT	Everett TS	840	1090	1210
E9V	Alliston JCT	Everett JCT	840	1090	1400
E9V	Alliston JCT	Alliston TS	840	1090	1400
E9V	Alliston JCT	Alliston JCT	840	1090	1400
E9V	Essa TS	Alliston JCT	840	1090	1400
E9V	Everett JCT	Orangeville TS	840	1090	1400

Circuit Name	From	To	Continuous	LTE	STE
E9V	Everett JCT	Everett TS	840	1090	1210
M6E	Bracebridge JCT	Bracebridge TS	810	810	810
M6E	Bracebridge JCT	Muskoka TS	550	550	550
M6E	Cooper's Falls JCT	Orillia TS	440	440	440
M6E	Cooper's Falls JCT	Bracebridge JCT	550	550	550
M6E	Midhurst TS	Essa TS	840	1070	1180
M6E	Minden TS	Cooper's Falls JCT	440	440	440
M6E	Orillia TS	Midhurst TS	550	550	550
M7E	Bracebridge JCT	Muskoka TS	770	770	770
M7E	Cooper's Falls JCT	Orillia TS	550	550	550
M7E	Cooper's Falls JCT	Bracebridge JCT	770	770	770
M7E	Midhurst TS	Essa TS	840	1090	1230
M7E	Minden TS	Cooper's Falls JCT	550	550	550
M7E	Orillia TS	Midhurst TS	770	770	770
M80B	Beaver JCT	Brown Hill TS	840	1090	1210
M80B	Beaver JCT	Beaverton JCT	840	1090	1400
M80B	Beaverton JCT	Beaver JCT	840	1090	1270
M80B	Beaverton JCT	Lindsay TS	840	1090	1400
M80B	Minden TS	Beaverton JCT	840	930	970
M81B	Beaver JCT	Beaverton JCT	840	1090	1400
M81B	Beaver JCT	Brown Hill TS	840	1090	1210
M81B	Beaverton JCT	Lindsay TS	840	1090	1200
M81B	Beaverton JCT	Beaver JCT	840	930	970

Circuit Name	From	To	Continuous	LTE	STE
M81B	Minden TS	Beaverton JCT	840	930	970
S2S	Meaford TS	Stayner TS	590	770	850
S2S	Owen Sound TS	Meaford TS	590	770	950

Table 6 - Winter Ratings of Monitored Circuits and Ratings

Circuit Name	From	To	Continuous	LTE	STE
D1M	Des Joachims TS	Minden TS	750	750	750
D2M	Des Joachims TS	Otter Creek JCT	750	750	750
D2M	Otter Creek JCT	Minden TS	750	750	750
D2M	Otter Creek JCT	Wallace JCT	750	750	750
D2M	Wallace JCT	Wallace TS	750	750	750
D3M	Des Joachims TS	Minden TS	750	750	750
D4M	Des Joachims TS	Otter Creek JCT	750	750	750
D4M	Otter Creek JCT	Minden TS	750	750	750
E20S	Essa TS	Stayner TS	1020	1230	1340
E21S	Essa TS	Stayner TS	1020	1230	1340
E26	Essa TS	Waubaushene JCT	1020	1200	1300
E26	Holmur JCT	Parry Sound JCT	1020	1230	1510
E26	Holmur JCT	Holmur SS	1020	1190	1280
E26	Parry Sound JCT	Parry Sound TS	1020	1230	1510
E26	Waubaushene JCT	Waubaushene TS	1020	1230	1510
E26	Waubaushene JCT	Holmur JCT	1020	1190	1280
E27	Essa TS	Waubaushene JCT	1020	1230	1370
E27	Holmur JCT	Parry Sound JCT	1020	1230	1370
E27	Holmur JCT	Holmur SS	1020	1190	1280
E27	Parry Sound JCT	Parry Sound TS	1020	1230	1370
E27	Waubaushene JCT	Waubaushene TS	1020	1230	1510

Circuit Name	From	To	Continuous	LTE	STE
E27	Waubaushene JCT	Holmur JCT	1020	1230	1370
E28	Allandale TPS JCT	Barrie TS	1420	1720	2000
E28	Allandale TPS JCT	Allandale TPS	750	750	750
E28	Essa TS	Allandale TPS JCT	1420	1720	2000
E29	Allandale TPS JCT	Barrie TS	1420	1720	2000
E29	Allandale TPS JCT	Allandale TPS	750	750	750
E29	Essa TS	Allandale TPS JCT	1420	1720	2000
E8V	Alliston JCT	Everett JCT	1020	1230	1510
E8V	Alliston JCT	Alliston TS	1020	1230	1510
E8V	Alliston JCT	Alliston JCT	1020	1230	1510
E8V	Essa TS	Alliston JCT	1020	1230	1510
E8V	Everett JCT	Orangeville TS	1020	1180	1270
E8V	Everett JCT	Everett TS	1020	1230	1340
E9V	Alliston JCT	Everett JCT	1020	1230	1510
E9V	Alliston JCT	Alliston TS	1020	1230	1510
E9V	Alliston JCT	Alliston JCT	1020	1230	1510
E9V	Essa TS	Alliston JCT	1020	1230	1510
E9V	Everett JCT	Orangeville TS	1020	1230	1510
E9V	Everett JCT	Everett TS	1020	1230	1340
M6E	Bracebridge JCT	Bracebridge TS	1000	1000	1000
M6E	Bracebridge JCT	Muskoka TS	750	750	750
M6E	Cooper's Falls JCT	Orillia TS	760	760	760
M6E	Cooper's Falls JCT	Bracebridge JCT	750	750	750

Circuit Name	From	To	Continuous	LTE	STE
M6E	Midhurst TS	Essa TS	1020	1210	1310
M6E	Minden TS	Cooper's Falls JCT	760	760	760
M6E	Orillia TS	Midhurst TS	750	750	750
M7E	Bracebridge JCT	Muskoka TS	970	970	970
M7E	Cooper's Falls JCT	Orillia TS	750	750	750
M7E	Cooper's Falls JCT	Bracebridge JCT	970	970	970
M7E	Midhurst TS	Essa TS	1020	1230	1350
M7E	Minden TS	Cooper's Falls JCT	750	750	750
M7E	Orillia TS	Midhurst TS	970	970	970
M80B	Beaver JCT	Brown Hill TS	1020	1230	1340
M80B	Beaver JCT	Beaverton JCT	1020	1230	1510
M80B	Beaverton JCT	Beaver JCT	1020	1230	1390
M80B	Beaverton JCT	Lindsay TS	1020	1230	1510
M80B	Minden TS	Beaverton JCT	1020	1090	1130
M81B	Beaver JCT	Beaverton JCT	1020	1230	1510
M81B	Beaver JCT	Brown Hill TS	1020	1230	1340
M81B	Beaverton JCT	Lindsay TS	1020	1220	1330
M81B	Beaverton JCT	Beaver JCT	1020	1090	1130
M81B	Minden TS	Beaverton JCT	1020	1090	1130
S2S	Meaford TS	Stayner TS	720	870	940
S2S	Owen Sound TS	Meaford TS	720	870	1020

D.4 Credible Planning Events & Criteria

D.4.1 Studied Contingencies

Table below shows the contingencies assessed in the technical report.

Table 7 - Contingencies to be Assessed

Pre-contingency	Contingency[10]	Type	Mapping to TPL/ Directory 1 Event	Rating[11]	Maximum Allowable Load Loss
All in-service	None	N-0	P0	Continuous	None
All in-service	Single	N-1	P1, P2	LTE	150 MW by-configuration
All in-service	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW lost by curtailment; 600 MW Total
Local Generation out-of-service	None	N-0	N/A	Continuous	None
Local Generation out-of-service	Single	N-1	P3	LTE	150 MW by-configuration; >0 MW lost by curtailment[12]; Total 150 MW
Transmission element out-of-service, followed by system adjustments	Single	N-1-1	P6	STE, reduced to LTE	150 MW lost by curtailment; Total 600 MW

[10] Single contingency refers to a single zone of protection: a circuit, transformer, or generator. Double contingency refers to two zones of protection; the simultaneous outage of two adjacent circuits on a multi-circuit line, or breaker failure.

[11] LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.

STE: Short-term emergency rating. 15-min rating for circuits and transformers.

[12] Only to account for the magnitude of the generation outages

The lists below show the specific single, common tower, and breaker failure contingencies to be studied. Note that:

- Breaker failures and transformer failures that result in the same post-contingency state as the N-1 already documented are omitted.
- The outage events used for the N-1-1 and N-1-2 studies are very similar to the N-1 contingencies documented in below but may be slightly different in some cases to reflect the fact that outages are the removal of a single element rather than all elements in a single zone of protection. For example, if the circuits have a capacitor, the capacitor is taken out of service for the contingency but not in an outage situation.

The specific single contingencies (N-1) studied are:

- E8V
- E9V
- E20S
- E21S
- E26
- E27
- E28
- E29
- M6E
- M7E
- M80B
- M81B
- D1M
- D2M
- D3M
- D4M
- Essa T3
- Essa T4

The specific common tower and breaker failure contingencies (N-2) studied are:

- D1M + D2M
- E8V + E9V
- E20S + E21S

- E26 + E27
- E28 + E29
- M6E + M7E
- M80B + M81B
- Essa AL26
- Essa AL6
- Essa AL8
- Essa HT4
- Essa HL7
- Essa HL9
- Essa HT3L9
- Essa HT3L6
- Essa L7L20
- Essa L8L20
- Essa T4L26
- Essa CB1[13]
- Essa CB2[7]
- Essa CB3[7]
- Minden AL1
- Minden AL2
- Minden AL3
- Minden AL4
- Minden L1L6
- Minden L2L7
- Minden L3L80
- Minden L4L81
- Minden HL6
- Minden HL7

[13] These are new circuit breakers to be installed at Essa TS following the completion of the Barrie Area Transmission Upgrade project. The name of this circuit breaker is subject to change and is located in Essa TS as per Figure 1 of the CAA 2016-580 Final Report.

- Minden HL80
- Minden HL81
- Holmur CSS L25L26
- Holmur CSS L25L27

D.4.2 Planning Criteria

The study will use the planning criteria in accordance with events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"),
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

D.4.2.1 Supply Capacity Requirements

All elements in-service – No Contingency

No issues have been identified with all elements in-service with no contingency.

All elements in-service – Loss of Single Contingency

As per Table 7, transmission system loading for the loss of a single contingency should not exceed LTE ratings with all elements in-service pre-contingency. With all elements in service, the following was seen for loss of a single contingency:

- The 230 kV circuit M7E section from Essa TS to Midhurst TS exceeds the LTE rating for the loss of M6E circuit by 4% in 2040 and it is at 87% of its LTE rating in 2030.
- The 230 kV circuit M6E section from Essa TS to Midhurst TS exceeds the LTE rating for the loss of M7E circuit by 11% in 2040 and it is at 87% of its LTE rating in 2040.
- The 230 kV circuit M6E section from Minden TS to Cooper's Falls JCT is just above the LTE rating for loss of M7E in 2040 and 87% of its LTE rating in 2030.
- Essa T3 is shown to be at 100% of its LTE rating for the loss of Essa T4 in 2022, followed by 111% in 2030 and 130% in 2040.
- Essa T4 is shown to be at 100% of its LTE rating for the loss of Essa T3 in 2040. The loss of an Essa autotransformer will be further considered as part of a bulk planning study.

All elements in-service – Loss of Double Contingency

As per Table 7, transmission system loading for a double contingency should not exceed STE ratings immediately after the contingency with all elements in-service pre-contingency. The 230 kV circuit M6E section from Essa TS to Midhurst TS exceeds the STE rating by 1% in 2040 for the Essa HL7, Essa L7L20 or Minden L2L7 breaker failure contingencies. In 2030, the loading of M6E for these double contingencies are at 84% of STE rating.

Local Generation out-of-service – No Contingency

No issues have been identified with local generation out-of-service with no contingency.

Local Generation out-of-service – Loss of Single Contingency

For the loss of a single contingency with a local generation out-of-service, the LTE rating should not be exceeded. The following was seen with local generation out-of-service:

- With Des Joachims G5 - G8 or with Henvey Wind Inlet GS out-of-service, the 230 kV circuit M7E section from Essa TS to Midhurst TS exceeds the LTE rating for the loss of M6E circuit by 7% or 4% in 2040 (89% and 86% of LTE rating in 2030).

- With Des Joachims G5 - G8 or with Henvey Wind Inlet GS out-of-service, the 230 kV circuit M6E section from Essa TS to Midhurst TS exceeds its LTE rating for the loss of M7E circuit by 13% or 10% in 2040 (95% and 92% of LTE rating in 2030).

- With Henvey Wind Inlet GS out-of-service, the 230 kV circuit M6E section from Minden TS to Cooper's Falls JCT exceeds the LTE rating for the loss of M7E circuit by 1% in 2040 (88% of LTE rating in 2030).

- With Henvey Wind Inlet GS out-of-service, Essa T3 is at 3% over its LTE rating for the loss of Essa T4 in 2022. This value increases to 14% in 2030 and 32% in 2040. Essa T4 is at 1% over its LTE rating in 2040. Consistent with the finding above, this will be further considered as part of a bulk planning study.

- With Des Joachims 5-8 GS out-of-service Essa, T3 is at 1% over its LTE rating for the loss of Essa T4 in 2022. This value increases to 12% in 2030 and 32% in 2040. Essa T4 is at 1% over its LTE rating in 2040. Consistent with the finding above, this will be further considered as part of a bulk planning study.

Transmission element out-of-service – Loss of Single Contingency

As per Table 7, with a transmission element out-of-service pre-contingency, transmission system loadings for the loss of a single contingency can go up to STE if there are control actions (e.g. SPS, generator re-dispatch) that can be used to reduce it to LTE ratings within the allotted time. If no control actions exist in the area, then LTE ratings should not be exceeded for a single contingency. For this analysis, we assume that there are no control actions available in this area.

- With M7E out-of-service pre-contingency, the section of M6E between Minden TS to Cooper's Falls JCT is over its LTE rating by 4% for the loss of M81B in 2040 and by 33% for loss of an Essa autotransformer. The section of M6E between Essa TS to Midhurst TD is over 10% of its LTE rating for the loss of one DxM circuit in 2040.

- With M7E out-of-service pre-contingency, the section of M6E between Essa TS to Midhurst TS is at 10% over its LTE rating for the loss of either D1M, D3M or D4M in 2040.

- With either Essa T3 or T4 out pre-contingency, the section of M6E between Minden TS to Cooper's Falls JCT is over its LTE rating by 28% for the loss of the companion Essa 500/230 kV transformer in 2022 and 50% in 2030.

- With M7E out-of-service pre-contingency, the section of M6E between Minden TS to Cooper's Falls JCT is over its LTE rating by 3% for the loss of Essa T3 in 2022. This increases to 17% in 2030 and 33% in 2040. The results are similar for the loss of Essa T4.

D.4.2.2 Step-Down Station Capacity Requirements

As shown in Table 8, there are step-down station capacity needs identified in Barrie TS, Everett TS and Waubaushene TS.

Table 8 – Step-down Station Summer Capacity Needs

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	175.0	175.0	136.1	159.5	184.3
Barrie TS	172.8	172.8	105.3	225.7	254.5
Beaverton TS	193.0	193.0	68.6	71.5	86.6
Bracebridge TS	75.0	75.0	27.4	27.6	29.2
Everett TS	86.0	86.0	83.1	94.8	167.9
Lindsay TS	161.0	161.0	84.2	89.3	104.3
Meaford TS	52.0	52.0	33.4	34.2	39.2
Midhurst TS	311.0	311.0	275.0	284.7	339.1
Minden TS	52.0	52.0	44.3	45.8	52.8
Muskoka TS	169.0	169.0	113.2	124.6	136.5
Orangeville TS	194.0	194.0	139.3	160.4	189.3
Orillia TS	154.0	154.0	105.0	119.9	134.6

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Parry Sound TS	102.0	102.0	44.8	53.8	58.2
Stayner TS	181.0	181.0	129.1	140.3	168.4
Wallace TS	49.0	49.0	35.9	36.5	38.5
Waubaushene TS	94.0	94.0	89.9	98.6	116.4

Table 9 – Step-down Station Winter Capacity Needs

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Alliston TS	190.0	190.0	114.7	136.9	158.0
Barrie TS	194.4	194.4	80.8	179.5	201.4
Beaverton TS	213	213	77.0	80.5	88.1
Bracebridge TS	75.0	75.0	34.1	34.6	36.4
Everett TS	86.0	86.0	58.1	66.3	136.0
Lindsay TS	182.0	182.0	92.2	98.2	106.9
Meaford TS	59.0	59.0	43.5	44.8	54.4
Midhurst TS	355.0	355.0	202.2	210.7	244.7
Minden TS	64.0	64.0	54.5	56.7	63.8
Muskoka TS	199.0	199.0	145.6	158.4	167.8
Orangeville TS	226.0	226.0	119.8	135.0	162.8
Orillia TS	175.0	175.0	107.8	123.3	132.9

Station	Cont. Rating (MW)	LTR Rating (MW)	2022 (MW)	2030 (MW)	2040 (MW)
Parry Sound TS	119.9	119.9	59.2	69.1	74.1
Stayner TS	202.0	202.0	135.0	145.1	175.1
Wallace TS	54.0	54.0	38.2	39.1	41.1
Waubaushene TS	104.0	104.0	74.4	80.5	88.9

Barrie TS

With the Barrie Area Transmission Upgrade (BATU) project underway, Barrie TS will have a 10-day LTR of 172.8 MW. The summer demand forecast will exceed the 10-day LTR by 2027.

Everett TS

Everett TS has a summer 10-day LTR of 86 MW. The summer demand forecast starts exceeding the 10-day LTR in 2025 and is exceeded by 82 MW in 2040.

Waubaushene TS

Waubaushene TS has a summer 10-day LTR of 94 MW. The summer demand forecast starts exceeding the 10-day LTR in 2027 and is exceeded by 22 MW in 2040.

D.4.2.3 Load Security

Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. The transmission system must exhibit acceptable performance while following specified design criteria contingencies. Load security criteria, as described by ORTAC Section 7.1, specify a load interruption limit of 150 MW for single element contingencies and 600 MW for double element contingencies. A summary of the load security criteria can be found in Table XX of the IRRP Report.

No load security need has been identified in the planning timeframe. For single contingencies, there is no loss of load greater than 150 MW by configuration and for double contingencies, there is no loss of load greater than 600 MW in the 20-year study period.

D.4.2.4 Load Restoration

No load restoration issues identified for the region.

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Appendix G

South Georgian Bay – Muskoka Regional Infrastructure Plan



South Georgian Bay-Muskoka

REGIONAL INFRASTRUCTURE PLAN

December 16, 2022

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

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Hydro One Networks Inc. (Distribution)
InnPower
Orangeville Hydro
Elexicon Energy
Lakeland Power
Epcor Electricity Distribution Ontario Inc
Newmarket-Tay Power Distribution Ltd
Wasaga Distribution Inc.

Disclaimer

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Technical Working Group.

Technical Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The participants of the South Georgian Bay-Muskoka Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Alectra Utilities Corporation ("Alectra")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangevile Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

This RIP is the final phase of the second cycle of the South Georgian Bay-Muskoka Regional Planning (RP) process. It follows the completion of the South Georgian Bay-Muskoka Integrated Regional Resource Plan ("IRRP") which was subdivided into two sub-regions; Barrie Innisfil and Parry Sound/Muskoka both completed in May 2022. This also follows completion of the South Georgian Bay-Muskoka Needs Assessment ("NA") and Scoping Assessment ("SA") in April 2020 and November 2020, respectively.

The South Georgian Bay-Muskoka RIP provides a consolidated summary of needs and recommended plans for the region over a 10-year planning horizon (2022-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer term needs and trend. All needs for this long-term horizon will be reviewed again and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in August 2017 with the publication of the South Georgian Bay-Muskoka RIP report, which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

I. Update on the needs identified during the previous regional planning cycle

The following needs and projects identified in the previous regional planning cycle have been completed:

- Orillia TS M6E/M7E Switches (2021) - Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS (2021) – Replacement of end-of-life (EOL) 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units.

The following needs and projects identified in the previous regional planning cycle are currently underway:

- Parry Sound TS (2023) - Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment.

- Barrie TS (2023) Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV.

- Orangeville TS (2023)- Replace existing T1/T2 230/44/27.6 kV 75/125 MVA transformers with two 230/27.6 kV 50/83 MVA units and reconfigure the dual voltage switchyard to a standard DESN that would supply the 27.6 kV load. Also replace and upgrade T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate additional capacity.

II. Newly Identified needs:

The major infrastructure investments in this 2nd cycle recommended by the TWG in the South Georgian Bay-Muskoka Region over the near and medium-term (2022-2032) period are given in Table 1 below, along with their planned in-service date and budgetary estimate for planning purposes.

Table 1. South Georgian Bay-Muskoka Region - Recommended Plans over the 2022-2032 Study Period

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[1]	Cost ($M)[2]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal - Transmission Line	M6E / M7E (Orillia TS x Coopers Fls)	Replace end- f-life (EOL) transmission line conductor (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace EOL transmission line conductor and associated assets (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace EOL transmission line conductor and associated assets (62 km)	HONI	2028	70
Asset Renewal - Transmission Station	Wallace TS	Replace existing EOL 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units	HONI	2025	25
	Midhurst TS	Replace existing 230/44kV 125MVA EOL transformer (T4) with a new 230/44kV 125MVA unit	HONI	2026	12
	Orillia TS	Replace existing EOL 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing EOL 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing EOL 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

The South Georgian Bay-Muskoka TWG recommends that Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 1 while keeping the TWG apprised of project status.

[1] Planned in-service dates are tentative and subject to change

[2] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The next regional planning cycle for the South Georgian Bay-Muskoka Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will start in Q2 2025. However, the next regional planning cycle can be started earlier if required to address any emerging needs.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SOUTH GEORGIAN BAY- MUSKOKA REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Alectra Utilities Corporation ("Alectra")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangeville Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

Electrical supply to the South Georgian Bay-Muskoka region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) Hydro One step-down transformer stations in the region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders. Figure 1-1 represents the South Georgian Bay-Muskoka Region Map.

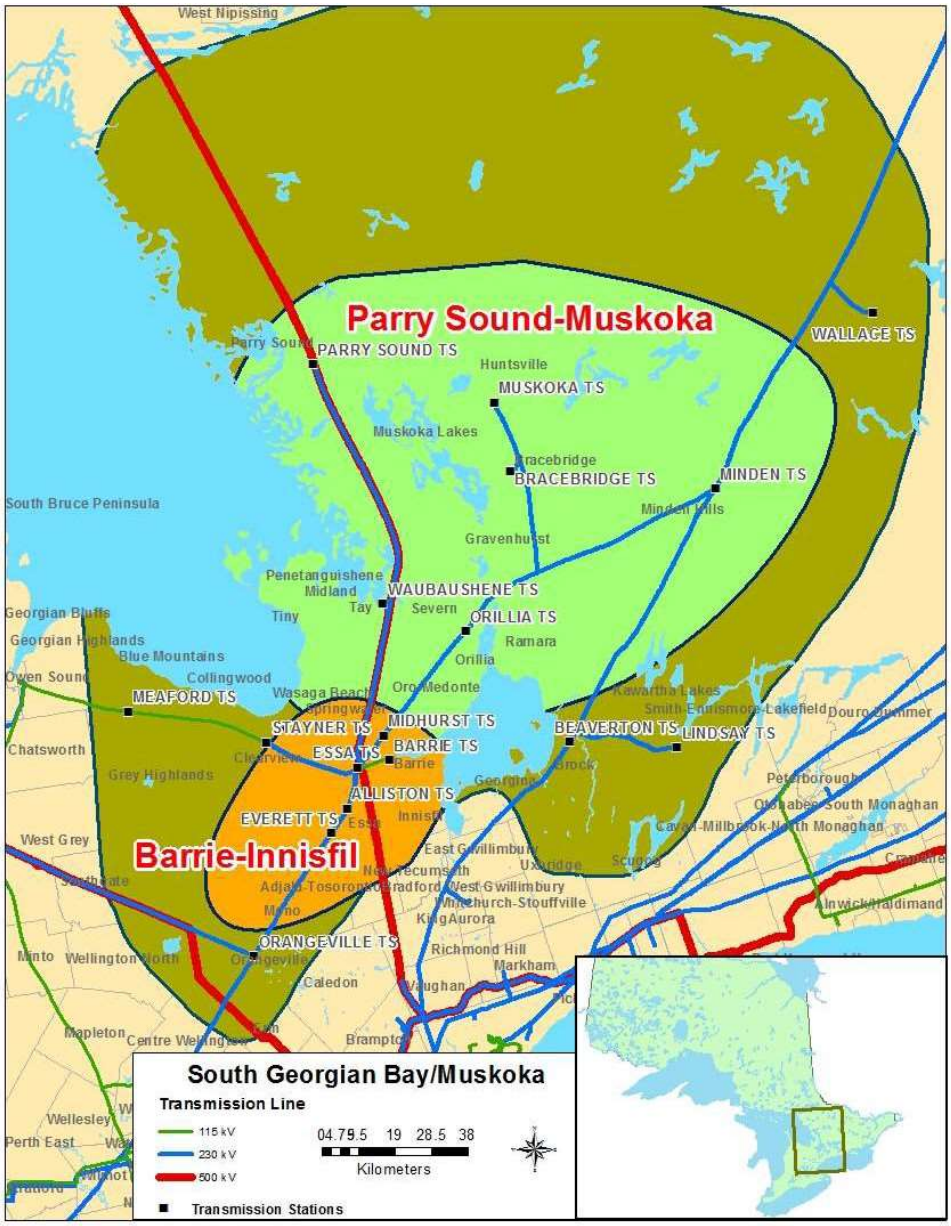


Figure 1-1 South Georgian Bay-Muskoka Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the South Georgian Bay-Muskoka Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs (2022-2032) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2022-2032 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the South Georgian Bay-Muskoka IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process;
- Section 3 describes the regional characteristics;
- Section 4 describes the transmission work completed over the last ten years;
- Section 5 describes the load forecast and study assumptions used in this assessment;
- Section 6 describes the results of the adequacy assessment of the transmission facilities in the region over the study period and identifies the needs;
- Section 7 discusses the needs, provides alternatives to address each need, and recommends a preferred solutions; and,
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: The Needs Assessment ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) determines whether further regional coordination is necessary to address them. If no further regional coordination is required to address the need(s), further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer to develop a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straightforward wires solution. The TWG considers various factors in determining that a LP is the appropriate planning approach.

In situations where identified needs require further coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the TWG, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and decides on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2 -1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

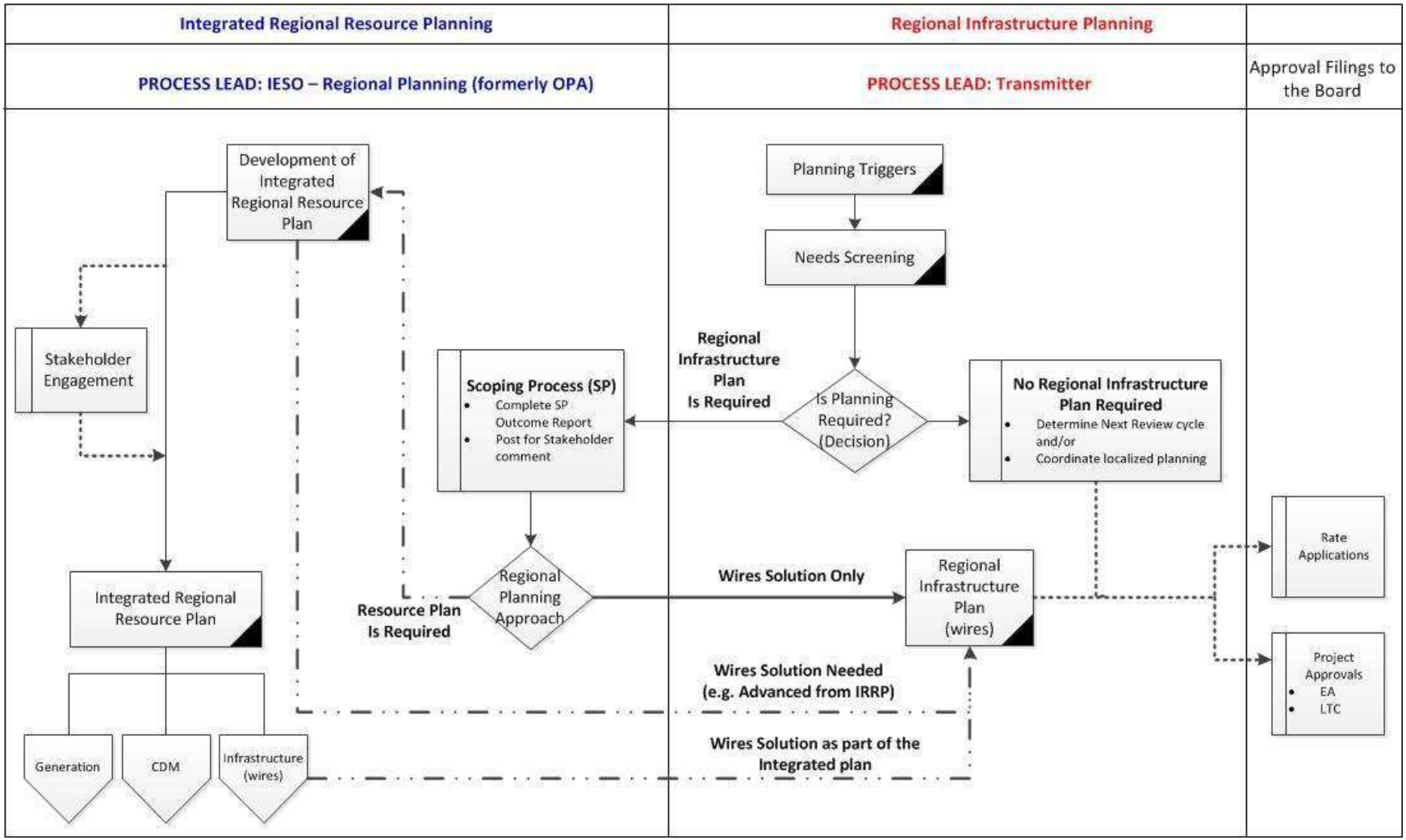


Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

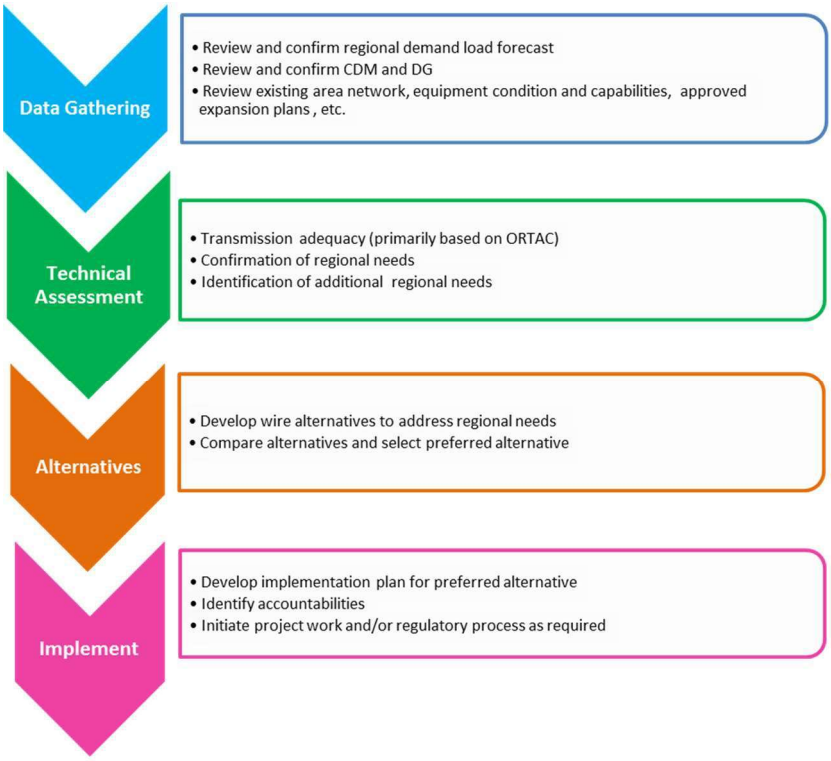


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/ INNISFIL AND THE PARRY SOUND/ MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4 M CONNECTING MINDEN TS TO DES JOACHIMS TS, THE 230 KV CIRCUITS E8V AND E9 V COMING FROM ORANGEVILLE TS AND THE SINGLE 115KV CIRCUIT S2S CONNECTING TO OWEN SOUND TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. The 500kV system is part of the bulk power system and is not studied as part of this report.

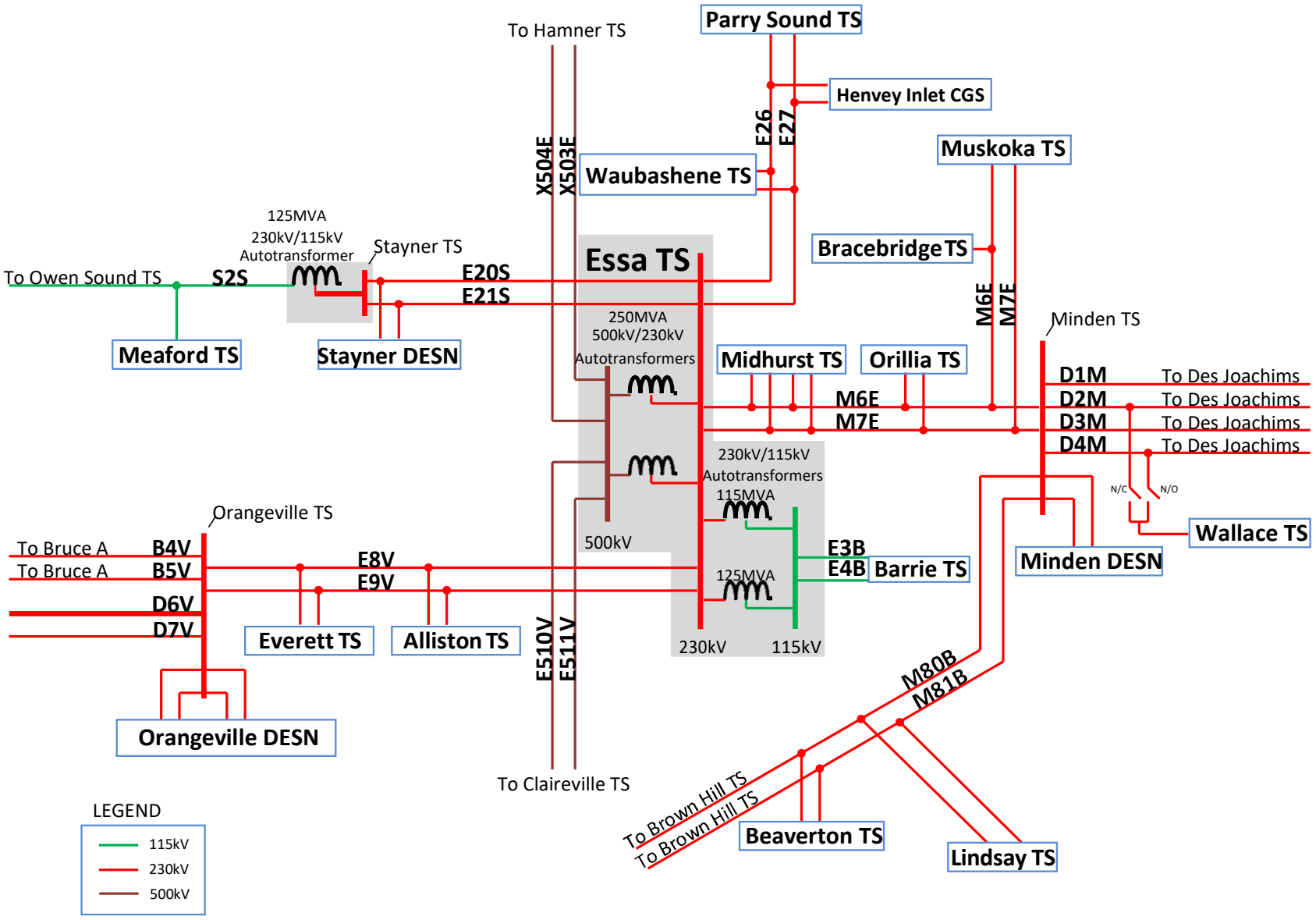
There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

The April 2020 South Georgian Bay/Muskoka Region second cycle NA report, prepared by Hydro One, considered the South Georgian Bay/Muskoka as a whole. Subsequently as a result of the Scoping Assessment, the South Georgian Bay/Muskoka Region was divided into two sub-regions, Barrie/Innisfil Sub-Region and Parry Sound-Muskoka Sub-Region.

The Barrie/Innisfil Sub-Region roughly encompasses the City of Barrie and the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury. It includes the townships of Essa, Springwater, Clearview and Mulmur, Adjala-Tosorontio. The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

This Parry Sound/Muskoka sub-region roughly encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County. The Parry Sound/Muskoka Sub-Region includes the areas supplied by Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS, and transmission circuits M6E/M7E and E26/E27.
The following circuits are not included in the South Georgian Bay/Muskoka Region:

- The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.
- The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.



Note: BATU project will convert E3B/E4B to 230kV and connect Barrie TS directly to Essa TS 230kV bus (In-Service 2023)

Figure 3-1 South Georgian Bay-Muskoka Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

A summary and brief description of the major projects completed and/or currently underway over the last ten years is provided below:

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44kV, 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (two banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and defer the overload on circuit M6E.

  Meaford TS Transformer Replacement (2015) – The 115/44 kV, 25/42 MVA T1/T2 transformers were at end-of-life (EOL) and replaced like-for-like.

- Orillia TS M6E/M7E Switches (2021) – Loss of M6E and M7E resulted in violation of ORTAC load restoration criteria based on the peak load forecast. Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS Transformer Replacement (2021) – The 230/44kV, 42MVA T1/T2 transformers were at EOL and replaced with new 230/44kV 83MVA units.

The following projects are underway:

- Barrie TS (2023) – This investment will convert the existing 115kV E3B/E4B circuits to 230kV and connect directly to the Essa 230kV bus. Barrie TS will be rebuilt with new 230/44kV 75/125MVA transformers and connect to the new 230kV E28/E29B circuits. The 230/115kV autotransformers at Essa TS will also be removed as part of this investment.

- Orangeville (2023) – Based on asset condition assessment the existing T3/T4 230/44kV 83MVA transformers will be replaced with new 125MVA units and also, the existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) be replaced with new dual winding 230/27.6, 83MVA units. This investment also involves reconfiguration of low voltage equipment and transfering existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN.

- Parry Sound TS (2023) - Parry Sound TS transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to their asset conditions. Hydro One will be installing new 230/44kV 83MVA transformers units to address both end of life and capacity needs at this station.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

During the study period, the load in the South Georgian Bay-Muskoka Region is expected to grow at an average annual rate of approximately 2% (summer) and 1.8% (winter) from 2022 to 2032.

Figure 5-1 shows the South Georgian Bay-Muskoka Region extreme summer weather net load forecast from 2022 to 2042. The load forecasts from the Barrie Innisfil sub-region IRRP and Parry Sound/Muskoka sub-region IRRP were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.
Non-coincident forecast for the individual stations in the region is available in Appendix D and is used to determine any need for station capacity relief.

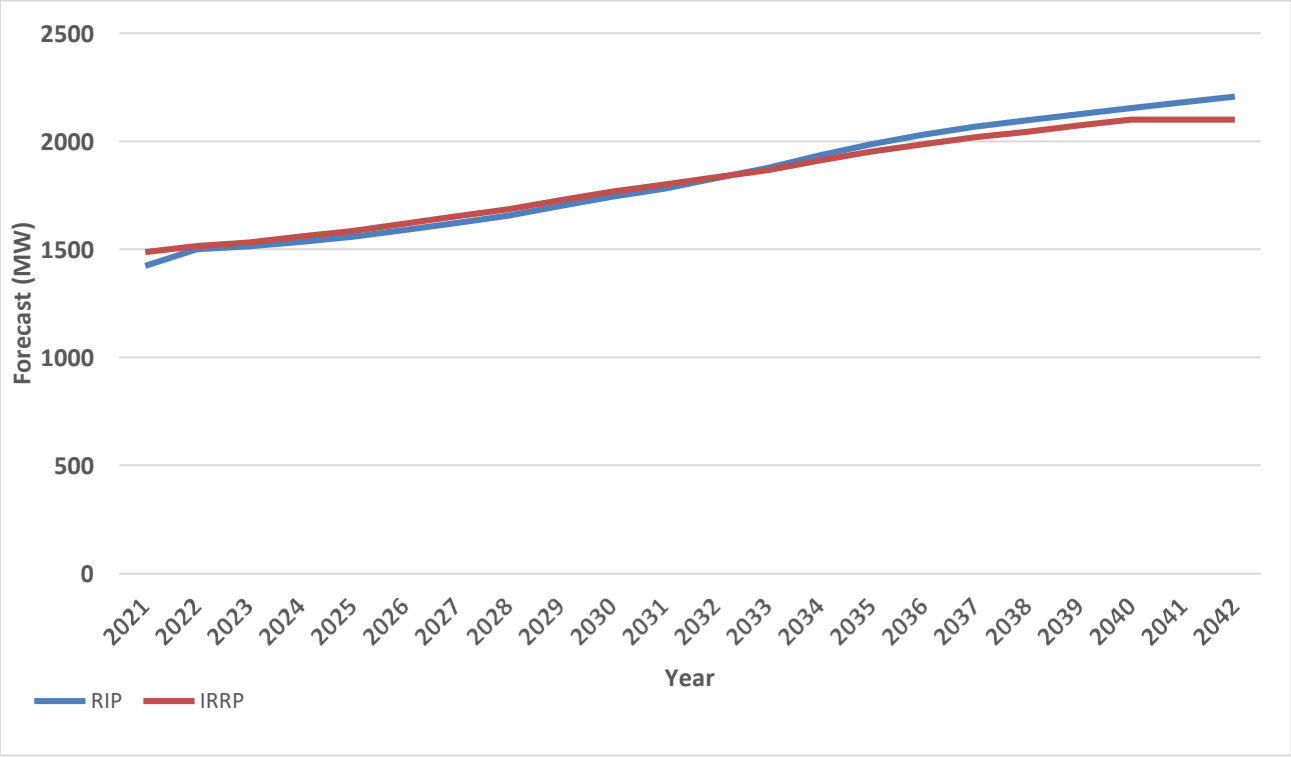


Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast

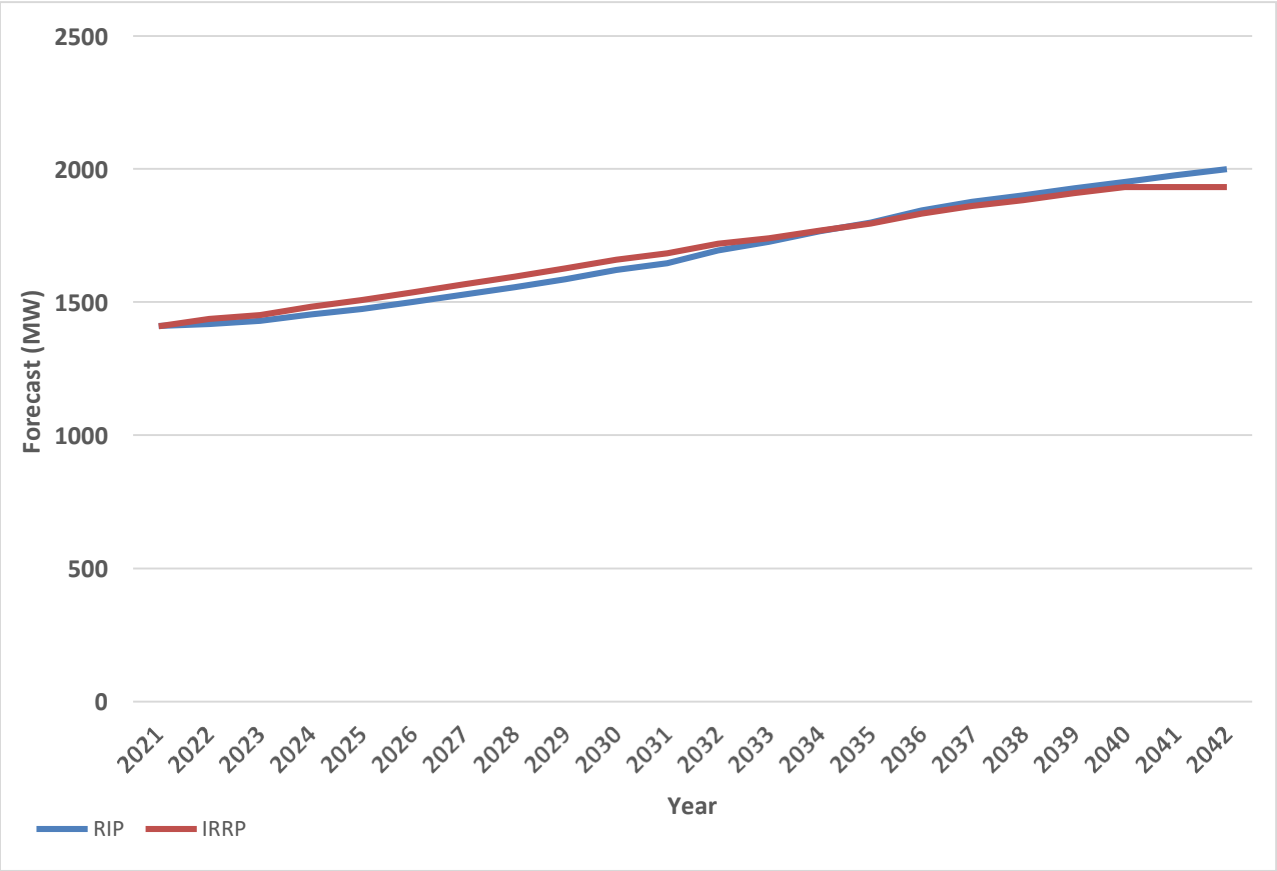


Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the IESO's Barrie Innisfil sub-region and Parry Sound/Muskoka sub-region IRRPs.
- LDCs reconfirmed load forecasts up to 2040. The additional two years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- Both summer and winter loads were considered to assess line and transformer loadings.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE SOUTH GEORGIAN BAY-MUSKOKA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, four regional assessments have been conducted for the South Georgian Bay-Muskoka Region. The findings of these assessments are inputs to this RIP. These assessments are:

1) South Georgian Bay-Muskoka Region second cycle Needs Assessment (NA) Report, April 2020
2) South Georgian Bay/Muskoka second cycle Scoping Assessment Outcome Report, November 2020
3) Barrie/Innisfil sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022
4) Parry Sound/Muskoka sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near to mid-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the South Georgian Bay/Muskoka Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service and specifically, the Barrie Area Transmission Reinforcement project and Orangeville/Parry Sound transformer replacements are in-service by 2023.

Sections 6.1- 6.3 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 500 kV and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the South Georgian Bay-Muskoka Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system. The 230 kV circuits also serve local area stations within the region and the power flow on these circuits vary depending on the bulk system transfers as well as the local area loads.

6.1.1 500/230 kV Transformation Facilities

Bulk power supply to the South Georgian Bay-Muskoka Region is provided by 500/230 kV autotransformers at Essa TS which serves as a hub for major power flows between Hanmer TS (Sudbury) and Clairville TS (Toronto). Additional support for the region is provided from the 230 kV generation facilities (Des Joachims GS, Henvey Inlet CGS)

6.1.2 230 & 115 kV Transmission Circuits

The 230kV circuits in the region are as follows;

- E20S/E21S (Essa TS x Stayner TS)
- E26/E27 (Essa TS x Parry Sound TS)
- M6E/M7E (Essa TS x Minden TS)
- D1M/D2M/D3M/D4M (Minden TS x Des Joachims)
- 115 kV - S2S (Stayner TS x Owen Sound TS)

Table 6-1 below highlights the line section(s) and violations identified in the IRRP and reaffirmed in this RIP.

Table 6-1 South Georgian Bay-Muskoka Region - Lines Sections Exceeding ratings

No.	Line	Section	Contingency	Year Line Rating exceeded
1	M6E/M7E	Essa TS x Midhurst TS	N-1[1]	2034
2	M6E	Minden x Coopers Fls JCT	N-1[2]	2038
3	M6E	Minden x Coopers Fls JCT	N-1-1[3]	2040

[1] Loss of one of either M6E or M7E will result in overload of the companion circuit.
[2] Minden TS HL7 breaker fail.
[3] M7E O/S followed by loss of Essa TS T3

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Step-Down Transformation Facilities

There are sixteen (16) step-down transformer stations in the South Georgian Bay-Muskoka Region as listed in Table 6-2.

Table 6-2 South Georgian Bay-Muskoka Region - Step-Down Transformer Stations

Alliston TS	Everett TS	Minden TS	Parry Sound TS
Barrie TS	Lindsay TS	Muskoka TS	Stayner TS
Beaverton TS	Meaford TS	Orangeville TS	Wallace TS
Bracebridge TS	Midhurst TS	Orillia TS	Waubaushene TS

This RIP reviewed the step-down transformation capacity for the stations within the South Georgian Bay-Muskoka Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the 2022-2032 study period are shown in Table 6-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) 10-dayLTR.

Table 6-3 South Georgian Bay-Muskoka Region - Stations Requiring Relief in the study period (2022-2032)

Station	Capacity (MW)	2022 Loading (MW)	Need Date
Everett TS	86	85	Immediate
Barrie TS	162[3]	98	2027
Waubaushene TS	94	90	2027

Further, based on the load forecast, the stations requiring relief beyond the study period are listed below:

- Midhurst TS (T1/T2) – 2033
- Midhurst TS (T3/T4) – 2034

6.3 Asset Renewal for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period as listed in Table 6-4 below.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as (but not limited to):

- Equipment deterioration;
- Technical obsolescence due to outdated design;
- Lack of spare parts availability or manufacturer support; and/or,
- Potential health and safety hazards, etc.

The major high voltage equipment considered includes the following:

1. 230/115kV autotransformers;
2. 230 and 115kV load serving step-down transformers;
3. 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two
4. 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
5. 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

[3] After completion of the BATU project

Table 6-4 South Georgian Bay-Muskoka Region - Planned Replacement Work

No.	Station / Line Section	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS (T1/T2)	2023
2	Orangeville TS (T1/T2 & T3/T4)	2023
3	Parry Sound TS (T1/T2)	2023
	In Development	
4	Wallace TS (T3/T4)	2025
5	Midhurst TS (T4)	2026
6	Orillia TS (T2)	2025
7	Bracebridge TS (T1)	2026
8	Waubaushene TS T5/T6	2027
9	Alliston TS (T3/T4)	2030
10	M6E/M7E – Cooper Falls Jct x Orillia TS	2026
11	E8V/E9V – Orangeville TS x Essa Jct	2027
12	D1M/D2M – Otter Creek Jct x Minden TS	2028

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[4] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interruped in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

[4] These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The electrical infrastructure needs for the South Georgian Bay-Muskoka Region are summarized in Table 7-1. These needs include those previously identified in the NA for the South Georgian Bay-Muskoka Region and IRRPs for the Barrie/Innisfil and the Parry Sound/Muskoka Sub-Regions as well as any new needs identified during the RIP phase. All estimated costs included in the altnerative analysis are considered as planning budgetary estimates and are used for comparative purposes only.

Table 7-1 South Georgian Bay-Muskoka Region – Near, Medium and Long Term Needs

Type	Section	Needs	Timing
Station Capacity	7.1	Everett TS	2023
		Barrie TS	2027
		Waubaushene	2027
		Midhurst TS	2033/2034
		Minden TS	2036
Supply Capacity	7.2	M6E/M7E (Essa x Midhurst)	2034
		M6E/M7E (Minden x Coopers Fls)	2038
Asset Renewal for Major HV Transmission Equipment	7.3.1	M6E/M7E (Orillia x Coopers Fls)	2026
		E8V/E9V (Orangeville TS x Essa Jct)	2027
		D1M/D2M (Otter Creek Jct x Minden TS)	2028
	7.3.2	Wallace TS (T3/T4)	2025
		Midhurst TS (T4)	2026
		Orillia TS (T2)	2025
		Bracebridge TS (T1)	2026
		Waubaushene TS (T5/T6)	2027
		Alliston TS (T3/T4)	2030
Load Security/Restoration	7.4	None Identified in this planning cycle	-

7.1 Station Capacity Needs

7.1.1 Everett TS

Everett TS is 230/44kV 50/83MVA transformer station with a summer and winter 10-Day LTR of 86MW. Load at this station is forecasted to increase up to 105MW by the end of 2032. Supply capacity is presently limited by a current transformer (CT) ratio setting on the transformer breaker bushing, thereby restricting the ability to utilize the full supply capability of the transformers.

Table 7-2 Everett TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Everett TS	86	85	86	87	88	90	92	93	95	97	100	105

The following alternatives were considered to address Everett TS capacity need:

Alternative 1 - Maintain Status Quo: This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.

Alternative 2 – Replace and upgrade T1/T2 with new 75/125MVA units: Under this alternative the existing T1/T2 transformers will be replaced with new 75/125MVA transformers. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire the T1/T2 transformers. These transformers remain in acceptable condition are not scheduled to be replaced by Hydro One within the study period.

Alternative 3 – Modify the CT Ratio: This alternative would require modifying the CT ratio of the low voltage transformer breaker CTs to realize the full supply capacity of the transformers.

The TWG recommends Alternative 3 as the preferred and cost effective alternative for addressing the need. CT ratios are established based on expected loading at a station and typically lower when transformer stations are initially constructed. As the load increases these ratios must be adjusted to ensure protection, control and metering continue to operate as intended. This solution utilizes existing assets without incurring additional high capital expenditures and will allow the station LTR to increase to 108MW (summer) and 177MW (winter) once completed. The budgetary cost for this alternative is expected to be $0.5M

7.1.2 Barrie TS

The Barrie Area Transmission Upgrade (BATU) project is presently underway and scheduled to be in-service in 2023. Barrie TS will be upgraded to a new 230/44kV 125MVA transformer station with 8 feeder positions (six for Alectra Utilities and two for Hydro One Distribution with InnPower as an embedded customer).

Barrie TS will have a 10-Day LTR of 162MW and the forecasted load will exceed its normal supply capacity in 2028 based on the summer demand forecast (see Table 7-3 below). Coincident with the station capacity violation, Hydro One distribution and its embedded LDC (InnPower) will also see a supply capacity constraint on their two 44kV feeders in 2028. Minor capacity increases can be accommodated on the 44kV system, but only on an emergency basis and cannot be used as a permanent supply solution for increased load growth. InnPower will

need new supply capacity into the Innisfil service territory to service its load growth beyond the 2-feeder capacity that Barrie TS can supply.

An Innisfil supply study was completed to evaluate supply options for InnPower and consequently help to offload demand from Barrie TS. Results of this study are described in the alternatives below.

Table 7-3 Barrie TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Barrie TS	162	98	119	128	141	154	161	163	164	167	170	174

Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address future station capacity restrictions at Barrie TS, nor does it provide InnPower with the mid-term supply capacity required for load growth in their service territory.

Alternative 2 – Inn Power to connect to existing Alectra Feeder as embedded customer:

This solution was initially discussed by the TWG in the first planning cycle to provide increased supply to InnPower without additional station work at Barrie TS. Spare feeder capacity is not available and thus, this alternative fails to meet the full supply needs within the study period and will need to be combined with alternate solutions. This alternative was rejected on this basis, and thus costs have not been explored further.

Alternative 3 – Install an Additional 44kV feeder position from Barrie TS:

This solution was discussed with the TWG and closely relates to Alternative 2. A new dedicated feeder position for InnPower will provide up to 25MW supply capacity, however this solution would still fail to meet the full supply needs of InnPower within the study period, and the increased load will still be seen at Barrie TS triggering a capacity need in 2028. This solution will need to be combined with alternate solutions to relieve Barrie TS. The combined transmission and distribution costs to install and construct a new distribution line from Barrie TS is estimated to cost $20M, however this alternative is rejected as it does address capacity needs at Barrie TS.

Alternative 4 – Load existing 44kV supply feeders beyond normal capacity

This alternative was explored by the TWG to increase supply on the two 44kV feeders from Barrie TS beyond the normal supply capacity. This solution requires increased voltage support on the distribution system along the feeders and will provide up to 20MW increased supply capacity (10MW/feeder). Distribution costs to facilitate increased feeder loading is estimated to cost $8M, however this alternative is rejected as it still does address Capacity needs at Barrie TS.

Alternative 5 – Provide 230kV tap connection to Innisfil service territory for new transformer station

This alternative involves construction of a 230/27.6kV 50/83MVA transformer station in Innisfil to supply the increased load demand forecast. This station will connect directly to the 230kV E28B/E29B circuits which will be completed in 2023 as part of the Barrie Area Transmission Upgrade project. A new 9km double circuit 230kV transmission line will be constructed to connect this new transformer station.

This alternative will provide increased supply capacity for InnPower within the study period and allow for load growth in the future. This alternative can be utilized as a standalone solution to meet the needs without additional interim investments or in conjunction with other alternatives presented above. This solution also allows InnPower to transfer load to this station which would otherwise be connected to Alliston TS. This transfer of load helps to mitigate a capacity need during the study period which would see an additional expenditure to increase supply capacity on the T3/T4 DESN at Alliston TS.
The estimated cost for this investment is expected to be $44M which is comprised of $14M for transmission line construction and $30M for a new transformer station.

The TWG recommends proceeding with Alternative 5. This alternative provides a robust transmission solution to meet InnPower's demand forecast and will also allow for future load growth beyond the study period. This solution will also help to relieve Barrie TS which will see a capacity need in 2028. Based on findings in the Needs Assessment and IRRP, Hydro One and InnPower have commenced development work on this alternative to meet the 2028 need date and TWG recommends continuing with this work.

7.1.3 Waubaushene TS

Waubaushene TS presently has 230/44 83MVA transformers (T5/T6) with a summer LTR of 94MW. This station will exceed its normal supply capacity in 2028 (see Table 7-4 below).

Summer overloading at this station continues to be of concern and the TWG agrees that a solution is required to address this need. Hydro One Distribution has permanently transferred 10MW of load from Waubaushene TS to Midhurst TS to help with recent summer loading concerns, however a solution is required to further address the upcoming supply capacity need.

Table 7-4 Waubaushene TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Waubaushene TS	94	90	90	91	92	93	94	96	97	99	100	102

Alternative 1 - Maintain Status Quo: This solution is not recommended as it does not address the supply capacity need at the station. This solution will prevent load growth at this station beyond 2027.

Alternative 2 – Load Transfer to neighboring stations

This solution was explored during the NA and IRRP phase. Hydro One distribution assessed transfer capability to other stations and determined that a maximum of 10MW of load could be transferred, and this was completed in Q1 2022. Further transfers are not feasible without significant distribution construction costs and regulators on the low voltage network estimated to be $ 5-10 M depending on feeder construction and voltage regulation.

Alternative 3 – Replace End-of-Life Waubaushene TS T5/T6 transformers with upgraded 125MVA units.

Replace and upgrade existing T5/T6 transformers with larger 75/125MVA units. This solution will increase supply capacity to allow load to continue to grow as per the demand forecast.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative for addressing the need. The existing T5/T6 transformers at Waubaushene TS have been identified by Hydro One as requiring replacement based on their asset condition and is planned for replacement in 2027. This date coincides with the supply capacity need timing as shown in Table 7.4 and thus the TWG agrees this is the ideal scenario to address the capacity need and right size the transformers. The budgetary cost for the replacement and upgrade of the transformers is expected to be $20M. Hydro One will follow Ontario Energy Board (OEB) approved procedures to determine appropriate cost allocation as this project addresses both a sustainment and capacity upgrade need.

7.1.4 Midhurst TS and Minden TS

As identified in Table 7-1, the stations listed below will require capacity relief beyond 2032. Based on the long-term horizon of these needs the load at these stations will be reviewed in the next regional planning cycle. The timing for capacity relief of these stations is shown below:

- Midhurst TS T1/T2: 2033 and Midhurst TS T3/T4: 2034
- Minden TS T3/T4: 2036

7.2 Supply Capacity Needs

The M6E/M7E circuits are a 230kV double circuit transmission line forming a critical path between Essa TS and Minden TS. These circuits are approximately 120 km long and serve to provide connection to load serving stations and provide a path for network flows. Based on the coincident load forecast of the stations in the region, sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The two circuit sections are described below:

1. Essa TS x Midhurst TS (10km) – For the loss of M6E or M7E, the companion circuit will exceed its Long-Term Emergency (LTE) rating as early as 2034 based on the load forecast.

2. Minden TS x Coopers Falls JCT (51km) – This section of transmission line will experience Long-Term Emergency (LTE) rating violations as early as 2038 for a Minden TS HL7 breaker failure, and Essa T3 contingency with M7E out of service.

Based on the long-term horizon of these needs solutions to address them will be further explored in the next regional planning cycle. Flows on this line and its violations are heavily influenced by area resource assumptions and demand forecast of the transformer stations connected to this circuits. IESO has also identified that incremental cost effective CDM, storage and other non-wires alternatives will be explored to address this need. The TWG will review this need in the next regional planning cycle and initiate an investment should this violation be advanced due to changing system conditions.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

The asset renewal assessment considers options for right sizing the equipment such as:

- Maintaining the status quo;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all the load to other existing facilities;
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement); and,
- Replacing equipment with higher ratings and built to current standards.

7.3.1 Transmission Line Refurbishment

The following transmission line sections were identified by Hydro One as requiring refurbishment over the study period based on asset condition assessment:

1. M6E/M7E Orillia x Coopers Fls – This is a 50km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2026.

2. E8V / E9V Orangeville TS X Essa JCT – This is a 112km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2027.

3. D1M / D2M Otter Creek JCT x Minden TS – This is a 124km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2028.

7.3.2 Transmission Station Refurbishment

Hydro One identified a number of step-down transformers as requiring replacement over the study period based on asset condition assessment. Details of the planned work as recommended by the TWG are given in Table 7-5 below.

Table 7-5 Asset Renewal Plan-Transmission Stations

No.	Station	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV. This investment is also known as Barrie Area Transmission Upgrade (BATU) and will include replacement of end of life equipment at Essa TS, in addition to increasing both station and supply capacity to the area.	2023
2	Orangeville TS Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 230/44kV 125MVA units. Replace and upgrade existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. This replacement plan will decrease the risk of equipment failure and contribute to maintaining supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	2023
3	Parry Sound TS Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment. Replacement of these power transformers will help to maintain the reliability of supply and provide increased supply capacity to customers in the area by right sizing to 83MVA units.	2024
	In Development	
4	Wallace TS Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units. Replacement of Oil circuit breakers will also be part of this investment. This investment will help maintaining reliability of supply to Hydro One Distribution customers and reduce the risk of interruptions caused by station equipment failure.	2025

5	Midhurst TS Replace existing 230/44kV 125MVA T4 transformer with a new like-for-like unit. The T3/T4 DESN presently supplies load to Alectra though 8 x 44kV feeders. T4 is the sole unit that has been identified as requiring replacement due to poor asset condition. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure. Load growth in the area will be reviewed in the next regional planning cycle. The TWG will ensure solutions to increase supply capacity in the region are explored in advance of the need date.	2026
6	Orillia TS Replace existing 230/44kV 125MVA T2 transformer with a new like-for-like 230/44kV 125MVA unit. The T1 transformer was replaced in 2015 after failure and does not require replacement during this study period. This investment will help maintain reliability of supply to Hydro One Distribution customersand decrease the risk of interruptions caused by failure of transformer T2.	2025
7	Bracebridge TS Replace existing 230/44kV 83MVA transformer (T1) with new like-for-like 230/44kV 83MVA unit. Bracebridge TS presently has one transformer (T1) and is used to supply 2 x 44kV feeders and a backup for industrial pipeline operation. The load at this station is not expected to trigger installation of a second transformer and thus like-for-like replacement of T1 will be sufficient during the study period. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2026
8	Waubaushene TS Replace existing 230/44 83MVA transformers (T5/T6) with new 125MVA units. This investment will help to maintain reliability of supply to area customers and provide increased supply capacity to meet demand forecast.	2027
9	Alliston TS Replace existing 230/44kV 83MVA transformers (T3/T4) with new like-for-like 230/44kV 83MVA units.	2030

	This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure and removal of legacy obsolete equipment.	

*The planned in-service year is tentative and is subject to change.

The above asset replacement plans have taken "right sizing" into consideration. All transformer replacements in the development phase are planned to be replacewith like-for-like units based on the load forecast in the study period and Hydro One standard equipment. The TWG recommends that Hydro One proceed with the above station sustainment work to ensure system reliability is maintained.

7.4 Load Security / Restoration

As indicated in section 6.4 there are no load security or restoration violations in the SGB-Muskoka region over the study period. The TWG will continue to monitor and take corrective action as needed.

7.5 Long Term Considerations

Like many other regions in Ontario, load growth in the SGB-Muskoka region will be directly impacted by new energy programs specifically those which help drive electrification. In addition, it is anticipated large market participants will also have incentive programs to modify operations/technologies to reduce greenhouse emissions. Details of how future programs will impact demand is unknown at this time thus the TWG will continue to monitor these trends throughout planning cycles to identify areas in need of investment.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near and medium-term planning horizon (2022-2032) are provided in Table 8-1 below, along with their planned in-service dates and budgetary estimates for planning purposes.

Table 8-1 Recommended Plans in Region over the Next 10 Years

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[5]	Cost ($M)[6]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and extend and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing end-of-life 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal Needs for Major HV Transmission Equipment	M6E / M7E (Orillia TS x Coopers Fls)	Replace transmission line conductor and associated assets. (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace transmission line conductor and associated assets. (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace transmission line conductor and associated assets. (62km)	HONI	2028	70
	Wallace TS	Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units.	HONI	2030	25
	Midhurst TS	Replace existing 230/44kV 125MVA transformer (T4) with a new 230/44kV 125MVA unit.	HONI	2026	12
	Orillia TS	Replace existing 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

[5] The planned in-service dates are tentative and subject to change.

[6] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The South Georgian Bay-Muskoka TWG recommends Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 8-1. All the other identified needs/options in the long-term will be further reviewed by the TWG in the next regional planning cycle.

9. REFERENCES

[1] Independent Electricity System Operator, Barrie/Innisfil IRRP (2022)

[2] Independent Electricity System Operator, Parry Sound Muskoka IRRP (2022)

[3] Hydro One, South Georgian Bay/Muskoka Needs Assessment (2020)

[4] Hydro One, South Georgian Bay/Muskoka RIP (2017)

[5] Independent Electricity System Operator, Barrie/Innisfil IRRP (2016)

[6] Independent Electricity System Operator, Parry Sound/Muskoka IRRP (2016)

[7] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 August 07, 2007

[8] Ontario Energy Board, Transmission System Code (2018)

[9] Ontario Energy Board, Distribution system Code (2022)

APPENDIX A. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS

No.	Transformer Stations	Voltages (kV)
1.	Alliston TS	230/44
2.	Barrie TS	115/44
3.	Beaverton TS	230/44
4.	Bracebridge TS	230/44
5.	Essa TS	500/230/115
6.	Everett TS	230/44
7.	Lindsay TS	230/44
8.	Meaford TS	230/44
9.	Midhurst TS	230/44
10.	Minden TS	230/44
11.	Muskoka TS	230/44
12.	Orangeville TS	230/44/27.6
13.	Orillia TS	230/44
14.	Parry Sound TS	230/44
15.	Stayner TS	230/115/44
16.	Wallace TS	230/44
17.	Waubaushene TS	230/44

APPENDIX B. SOUTH GEORGIAN BAY-MUSKOKA REGION - TRANSMISSION LINES

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	E20/E21S	Essa TS	Stayner TS	230
2.	E26/E27	Essa TS	Parry Sound TS	230
3.	M6E/M7E	Essa TS	Minden TS	230
4.	D1M/D2M	Minden TS	Des Joachims TS	230
5.	D3M/D4M	Minden TS	Des Joachims TS	230
6.	M80B/M81B	Minden TS	Brown Hill TS	230
7.	E3B/E4B	Essa TS	Barrie TS	115
8.	S2S	Stayner TS	Owen Sound TS	115

APPENDIX C. SOUTH GEORGIAN BAY-MUSKOKA REGION - DISTRIBUTORS

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX
2.	Alectra Utilities	TX/DX
3.	InnPower	DX
4.	Orangeville Hydro	DX
5	Elexicon Energy	DX
6.	Lakeland Power	DX
7.	EPCOR Electricity Dist. Ontario Inc.	DX
8.	Newmarket-Tay Power Distribution Ltd.	DX
9.	Wasaga Distribution Inc.	DX

APPENDIX D. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	74.7	44	44	44	44	45	45	45	45	46	46	47	48	48	49	50	51	51	52	53	54	55
Alliston TS	T3/T4	112	100.8	76	80	83	86	90	93	91	91	91	92	92	93	93	93	93	93	94	94	94	94	94
Barrie TS	T1/T2	170	162.0	98	119	128	141	154	161	163	164	167	170	174	178	183	189	195	203	213	222	232	233	233
Beaverton TS	T3/T4	204	193.8	69	69	69	69	70	70	71	71	71	72	73	75	78	82	82	83	83	86	87	87	87
Bracebridge TS	T1	83	74.7	27	27	27	27	27	27	27	27	28	28	28	28	28	29	29	29	29	29	29	30	30
Everett TS	T1/T2	86	77.4	85	86	87	88	90	92	93	95	97	100	105	111	119	130	140	149	156	164	171	171	172
Lindsay TS	T1/T2	169	160.6	84	85	85	85	86	87	88	89	89	90	92	94	97	100	101	101	102	103	104	105	105
Meaford TS	T1/T2	55	52.3	33	33	33	33	33	34	34	34	34	35	37	38	38	38	38	38	39	39	39	40	40
Midhurst TS	T1/T2	171	163	150	151	153	154	156	157	159	160	162	162	163	166	167	169	170	171	173	174	175	176	176
Midhurst TS	T3/T4	166	149.4	123	107	111	115	118	122	125	129	133	136	140	144	151	156	160	163	167	171	175	176	176
Minden TS	T1/T2	58	52	44	44	44	44	44	45	45	45	46	46	46	47	47	48	48	52	52	53	53	53	53
Muskoka TS	T1/T2	179	170.1	113	114	113	113	114	115	116	117	125	125	126	127	130	132	133	134	135	136	137	137	137
Orangeville TS	T1/T2	113	101.7	49	49	52	53	53	54	55	55	56	57	59	60	62	62	63	64	65	65	66	67	67
Orangeville TS	T3/T4	170	161.5	90	91	97	98	99	100	102	103	104	106	110	111	114	116	117	119	120	122	123	124	124
Orillia TS	T1/T2	162	153.9	105	106	106	107	107	108	109	119	120	121	122	123	128	130	131	132	133	134	135	135	135
Parry Sound TS	T1/T2	113	101.7	45	46	45	47	48	50	50	51	54	54	55	55	56	56	56	57	57	58	58	58	59
Stayner TS	T3/T4	191	181.5	129	130	130	131	133	135	136	138	140	143	145	147	150	152	159	161	163	166	168	170	171
Wallace TS	T3/T4	54	48.6	36	36	36	36	36	36	36	36	36	37	37	37	37	38	38	38	38	38	38	39	40
Waubaushene TS	T5/T6	99	94.1	90	90	91	92	93	94	96	97	99	100	102	107	108	111	113	114	115	116	117	117	117

Winter Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LV Cap	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	N	74.7	32	32	32	32	32	33	33	33	34	34	35	35	36	36	37	37	38	38	39	40	40
Alliston TS	T3/T4	128	N	115.2	80	69	74	78	81	85	88	87	86	87	87	87	88	88	88	88	88	89	89	89	88
Barrie TS	T1/T2	200	Y	190.0	74	88	97	109	119	127	127	129	131	133	136	140	144	149	153	160	168	176	184	185	186
Beaverton TS	T3/T4	224	Y	212.8	77	78	78	78	79	79	80	80	81	81	81	82	82	83	84	84	85	88	88	89	90
Bracebridge TS	T1	83	N	74.7	34	34	34	34	34	34	34	35	35	35	35	35	35	35	36	36	36	36	36	37	38
Everett TS	T1/T2	95	N	85.5	60	61	62	63	64	65	66	67	69	71	75	81	88	99	109	118	125	132	139	139	140
Lindsay TS	T1/T2	192	Y	182.4	92	93	94	94	95	96	97	98	98	99	100	101	102	102	103	104	105	105	107	106	107
Meaford TS	T1/T2	62	Y	58.9	43	44	44	44	44	44	44	45	45	45	52	52	53	53	53	54	54	54	54	55	56
Midhurst TS	T1/T2	194	Y	184.3	116	116	117	118	119	120	121	122	123	124	125	126	127	128	128	129	130	131	132	132	133
Midhurst TS	T3/T4	191	N	171.9	96	85	88	90	93	95	98	101	103	106	108	111	114	117	119	122	125	127	130	131	132
Minden TS	T1/T2	64	N	58	55	55	55	55	55	56	56	56	57	57	57	58	58	58	59	63	63	63	64	64	65
Muskoka TS	T1/T2	209	Y	198.6	146	146	146	147	148	150	151	151	158	159	160	161	162	163	164	165	166	167	168	168	169
Orangeville TS	T1/T2	133	N	119.7	42	42	45	46	46	46	47	47	47	48	52	52	55	55	56	56	56	57	57	58	58
Orangeville TS	T3/T4	200	Y	190.0	78	78	84	85	86	86	87	87	88	89	97	97	102	103	103	104	104	105	106	107	107
Orillia TS	T1/T2	184	Y	174.8	108	109	110	111	112	112	113	123	123	124	125	126	127	128	129	130	131	132	133	133	134
Parry Sound TS	T1/T2	133	N	119.7	59	60	60	62	64	65	66	66	69	69	70	70	71	71	72	73	73	74	74	75	76
Stayner TS	T3/T4	213	Y	202.4	135	136	137	138	139	141	142	144	145	147	148	150	152	154	167	169	171	173	175	176	178
Wallace TS	T3/T4	60	N	54.0	38	38	38	38	39	39	39	39	39	39	39	40	40	40	40	40	41	41	41	42	42
Waubaushene TS	T5/T6	109	Y	103.6	74	75	76	76	77	78	79	80	80	81	82	83	84	85	86	86	87	88	89	89	90

APPENDIX E. LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
GS	Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resource
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme



Appendix H

Renewable Energy Generation Investments Plan

INNPOWER CORPORATION

Renewable Energy Generation Investments Plan

Prepared for the

Independent Electricity System Operator

To accompany

InnPower Corporation's
2024 Cost of Service Application

December 13, 2022

1 Executive Summary

The following Renewable Energy Generation (REG) Investments Plan identifies investment requirements for accommodating Renewable Energy Generation connections and provides information to the Ontario Energy Board and interested stakeholders regarding the readiness of InnPower Corporation's distribution system to connect renewable energy generation. This includes investment requirements for any expansion or reinforcement necessary to remove grid constraints to accommodate the connections of renewable energy generation over the forecast period of 2023 to 2028.

There are approximately 2,261.415 kilowatts (kW) of renewable energy installations connected to InnPower's distribution system, and 500 kW of renewable energy installations connected to InnPower's sub-transmission system under Feed-in-Tariff (FIT) and microFIT programs, all of which are solar photovoltaic projects. This includes 7 FIT projects and 141 microFIT projects.

Power is supplied to InnPower owned distribution stations (DS) from three transmission stations (TS) owned by Hydro One Networks Inc. (HONI) at 44,000 volts, namely Alliston TS, Barrie TS and Everett TS. InnPower also owns four distribution feeders that are supplied power from two HONI owned distribution stations, at 8,320 volts, namely Cookstown West DS and Thornton DS, which are supplied by Everett TS and Alliston TS, respectively.

InnPower has analyzed its circuits for REG connectivity and calculated available capacity for REG connection on each feeder. InnPower is not proposing any capital investments to increase the capacity of its distribution system to enable further renewable energy generation connectivity, from 2023 to 2028.

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2 INTRODUCTION

InnPower Corporation (InnPower) is preparing to file a Cost of Service (COS) Application for the prospective rate year of 2024. In accordance with the Ontario Energy Board (OEB) *Filing Requirements for Electricity Transmission and Distribution Applications*, InnPower has prepared this Renewable Energy Generation (REG) Investments Plan to accompany its Distribution System Plan (DSP) and COS Application.

This REG Investments Plan provides information on InnPower's ability to accommodate new REG connections to its distribution system. The purpose of this REG Investments Plan is to inform the Independent Electricity System Operator (IESO) of any REG investments over the DSP period (2023-2028) and to request the IESO to provide a letter commenting on this information.

Section 3 of this REG Investments Plan provides background information regarding InnPower's distribution system. Section 4 lists the existing and proposed REG connections. Section 5 contains the system assessment to identify constraints. Finally, Section 6 summarizes the proposed investments to facilitate new REG connections.

For the purposes of this report, the terms *renewable energy generation* (REG) and *distributed energy resource* (DER) are considered interchangeable.

3 INNPOWER'S DISTRIBUTION GRID

InnPower Corporation owns, operates, and maintains a distribution system currently serving approximately 20,525 customers within an area of about 292 square kilometers. The service territory encompasses all of the Town of Innisfil, which includes the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. InnPower also serves communities in South Barrie. A majority of the customers are located in the above noted urban centers, with a smaller percentage of customers who are farmers.

InnPower has experienced steady growth within its service territory in the past ten years and expects this trend to increase significantly in the next decade. InnPower predicts its customer base will double in the next 8-12 years. InnPower's Business Plan and industry projections support this growth projection.

InnPower currently operates its sub-transmission system at 44,000 volts and its three-phase distribution system at 27,600 and 8,320 volts. InnPower owns, operates and maintains ten (10) distribution substations.

InnPower owns and maintains approximately 631 km primary overhead Line and 173 km primary underground line.

InnPower is embedded in Hydro One Networks Inc.'s (HONI) sub-transmission system. InnPower currently owns, operates, and maintains five (5) sub-transmission feeders from our border connection point, all of which have been identified by HONI to have available capacity to connect FIT or Micro-FIT generators.

3.1 MUNICIPAL SUBSTATIONS

InnPower has ten (10) distribution substations serving the Town of Innisfil and South of Barrie. The total capacity is 95 MVA.

Table 1: Distribution Feeder Data

SUBSTATION	SIZE (kVA)	OWNER	FEEDER #	Volt (kV)
Belle Ewart DS	10,000	InnPower	F1 & F2	44/27.6
Big Bay Point DS	10,000	InnPower	F1 & F2	44/27.6
Bob Deugo DS	10,000	InnPower	F1 & F2	44/27.6
Brian Wilson DS	10,000	InnPower	F1 & F2	44/27.6
	10.000		F3 & F4	
Cedar Point DS	5,000	InnPower	F1 & F2	44/8.32
	7,500		F3	
Innisfil DS	7,500	InnPower	F1, F2 & F3	44/8.32
Lefroy DS	5,000	InnPower	F1, F2 & F3	44/8.32
Leonards Beach DS	7,500	InnPower	F1, F2 & F3	44/8.32
Sandy Cove DS	5,000	InnPower	F1 & F3	44/8.32
	5,000		F2	
Stroud DS	5,000	InnPower	F1, F2 & F3	44/8.32

Table 2: Sub-transmission Feeder Capacity Status for DG Connectivity (HONI owned feeders)

Feeder	TS	Voltage	Rating	Available DG Capacity
9M1	Alliston	44kV	600 amps	27.5MVA
9M2	Alliston	44kV	600 amps	29.75MVA
9M4	Alliston	44kV	600 amps	29MVA
13M3	Barrie	44kV	600 amps	28.5MVA

3.2 Thermal Capacity Constraints

The thermal capacity of the distribution system is the ability of its equipment to carry current. Excessive current in the equipment will lead to overheating and failure. Cables and conductors are rated for the load current they carry. For main distribution feeders, InnPower strives to maintain 50% utilization of their rating such that two feeders can be connected for backup and improved system reliability.

Substation transformers are more sensitive to reverse power flow; therefore, InnPower calculates thermal capacity as 60% of the transformer's nameplate rating added to the minimum load of the transformer; based on Hydro One Networks Inc. (HONI) guidelines. The table below presents the available thermal capacity for Distributed Energy Resource (DER) connections at each substation transformer in InnPower's distribution system. The connected and in-progress DER includes both microgeneration feed-in-tariff (microFIT) and feed-in-tariff (FIT) connections for the purpose of the thermal capacity calculation. As shown, the DER nameplate ratings do not come close to the thermal capacity of the transformers. Note that Thornton DS and Cookstown West DS are both owned by HONI, therefore, approving any new DER connection on these DSs requires HONI consent as well. The thermal capacities for these two transformers were calculated based on their capacities and available data from the metering points (Utilismart). This can be changed according to HONI local loads.

Table 3: Available Thermal Capacity for DERs

Transformer	Nominal Rating (MVA)	2021 Minimum Load (MVA)	Total Thermal Capacity (MVA)	Connected and In-Progress DERs (MW)	Available Thermal Capacity (MVA)
Belle Ewart DS	10	2.26	8.26	0.40	7.86
Big Bay Point DS	10	1.16	7.16	0.00	7.16
Bob Deugo DS	10	1.04	7.04	0.18	6.86
Brian Wilson DS T1	10	1.43	7.43	0.22	7.21
Brian Wilson DS T2	10	1.7	7.70	0.22	7.48
Cedar Point DS T1	5	1.14	4.14	0.15	3.99
Cedar Point DS T2	7.5	0.64	5.14	0.00	5.14
Innisfil DS	7.5	1.83	6.33	0.41	5.92
Lefroy DS	5	0.60	3.60	0.09	4.51
Leonards Beach DS	7.5	1.28	5.78	0.10	5.68
Sandy Cove DS T1	5	0.80	3.80	0.01	3.79
Sandy Cove DS T2	5	0.17	3.17	0.00	3.17

Stroud DS	5	0.69	3.69	0.30	3.39
Cookstown West	7	1.27	5.47	0.21	HONI Station
Thornton	5	1.24	4.24	0.29	HONI Station

3.3 Voltage Regulation

InnPower is currently working on a digital distribution system model (CYME model) to include all DERs in the distribution system. The model will identify probable voltage regulation issues, as listed below:

- Low voltage downstream of a voltage regulator due to insufficient reactive power supplied by DERs
- Low voltage due to DERs drawing lagging reactive power
- High voltage due to real and leading reactive power produced by DERs
- Voltage unbalance for single phase DERs
- Excessive operation of voltage regulators due to DERs
- Reverse power flow through voltage regulation devices
- Improper voltage regulation when switching to alternate sources

4 EXISTING AND PROPOSED CONNECTIONS

As of this report date, there are a total of 141 DER installations presently connected to InnPower's distribution system under the Province's FIT and Micro-FIT programs, as summarized below and detailed in Table 4 and Table 5, respectively. In summary InnPower has:

- Seven FIT installations with generating capacity of 1,462.5 kW
- 135 Micro-FIT installations with 1,234.05 kW installed capacity
- Six solar net-metering installations with 55.865 kW installed capacity.

Table 4 – REG Applications Awaiting Approval for Grid Connection under the Micro-FIT Program

There are no applications awaiting approval for Grid Connection under Micro-FIT, as the program has ended.

Address	Capacity (kW)	Fuel Source	Station-TS	Feeder	Year
Total					

The number of REG connections over the five-year historical period is shown in Table 5. Hence, InnPower forecasts to connect similar to historical levels of new net-metering service a year over the 2023 to 2028 forecast period.

Table 5 – Connections for Services over the Historical Period (2017-2021)

Service	2017	2018	2019	2020	2021
	Count (#)	Count (#)	Count (#)	Count (#)	Count (#)
Micro-FIT	20	23	0	0	0
FIT	0	0	0	0	0
RESOP	0	0	0	0	0
Net Metering - Solar	1	2	0	1	3

InnPower does not expect any future REG connections >10kW for the period 2023 to 2028.

Table 6: Forecast REG for 2023-2027

Year	Projected # of Connections	Forecast kW
2023	0	0
2024	0	0
2025	0	0
2026	0	0
2027	0	0
2028	**0**	**0**
2023-2028 Totals	**0**	**0**

5 System Assessment to Identify Constraints

InnPower has analyzed its circuits for REG connectivity and calculated available capacity for REG connection on each feeder.

Based on these evaluations and considering the sum of both connections and applications, five of its distribution feeders (15.6%) have been identified on InnPower's distribution system as having reached the threshold for distributed generation connectivity (and three others are less than 20kW from reaching their threshold). The determination is based on the criteria described in the IEEE Standard 1547, which limits the total distributed generation connectivity to under 33% of the minimum load on a given feeder. Since all of InnPower's distributed generation connections use solar-based generation and all such generators use inverters that switch off when a frequency disparity is observed, the constraints noted in the above IEEE standard will therefore theoretically have little to no impact on creating islanding issues.

InnPower plans to import all DER information to its CYME model, which is based on the real-time system analysis and can determine actual constraints on the grid. InnPower will utilize the model to develop methodologies and specific projects to enhance REG connectivity subsequent to the Electro-Magnetic Transients Program (EMTP) analysis.

InnPower is currently in the process of implementing CYME to conduct the EMTP. Therefore, InnPower is not proposing any capital investments to mitigate constraints on the distribution system at this time.

5.1 Future Growth and its Impact on REG Connectivity

The noticeable increase in InnPower's customers, as well as the significant forecasted load growth within the next five years has resulted in the need to expand and upgrade infrastructure to meet new load demand. This infrastructure investment will further enhance REG connectivity, thus enabling more InnPower customers to utilize net metering.

6 PROPOSED INVESTMENTS TO FACILITATE NEW CONNECTIONS

InnPower has made significant capital investment for network expansion/reinforcement, which not only increases the InnPower network capacity, but also removes the grid constraints and accommodates the DER over the forecast period of 2023 to 2028.



Appendix I

IESO Response Letter

IESO response to InnPower REG Investments Plan 2023 – 2028

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricty System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On March 7, 2023, InnPower Corporation sent its REG Investments Plan (Plan) to the IESO for comment. The IESO has reviewed InnPower's Plan and reports that it contains no investments specific to connecting REG for the Plan period 2023 – 2028.

The IESO notes that InnPower's service territory is within the South Georgian Bay Muskoka (SGBM) region. The SGBM region finished its second cycle of regional planning with the publication of its Regional Infrastructure Plan (RIP)[1]. The RIP was published by Hydro One Networks Inc on December 16, 2022. The report identified the investements needed to be developed to meet the electricity needs in the region. InnPower was a participating member of the regional planning study team.

On Page 8 of its Plan, under the heading ***Exisitng and Proposed Connections***, InnPower states that "InnPower does not expect any future REG connections >10kW for the period 2023 to 2028".

As InnPower has determined it requires no system investments to connect REG over the 2023-2028 Plan period, the IESO submits that no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties[2].

The IESO appreciates the opportunity provided to review the REG Investments Plan and looks forward to working together in further regional planning processes.

[1] Hydro One's Regional Infrastructure Plan, December 16, 2022: www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/southgeorgianbaymuskoka/Documents/South_Georgian_Bay-Muskoka_Regional_Infrastructure_Plan_(RIP)_2022_12_16.pdf

[2] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

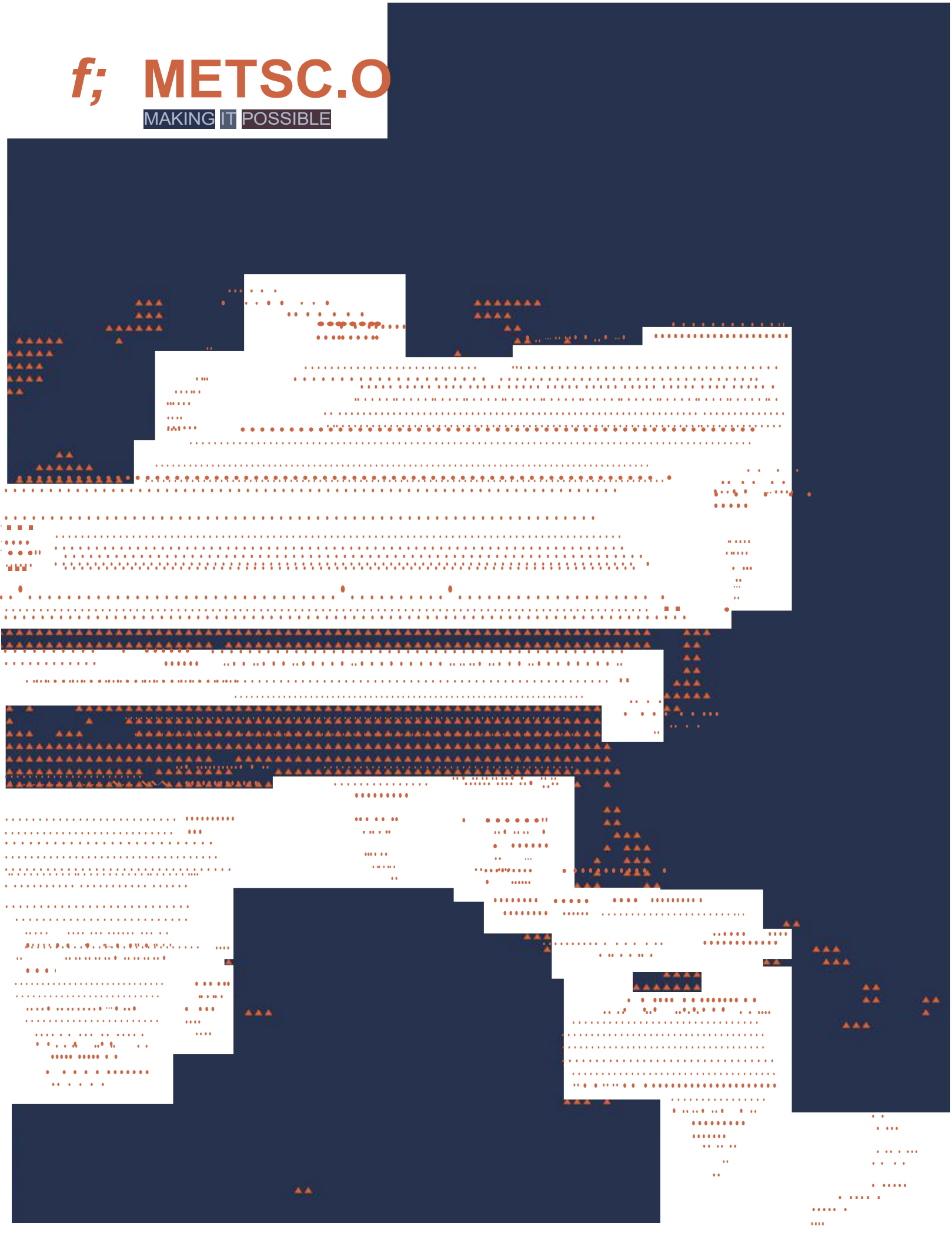


Appendix J

2021 Asset Condition Assessment Report

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MAKING IT POSSIBLE



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ASSET CONDITION ASSESSMENT FINAL REPORT 2021

Prepared by

METSCO Report no. P-21-145

15 Oct. 2021

Disclaimer

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Asset Condition Assessment Report 2021
Final Report

October 2021

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Executive Summary

Context of the Study

InnPower Corporation ("InnPower") is an electricity distributor operating in the regions of Innisfil and South Barrie. InnPower engaged METSCO to prepare a comprehensive ACA study for the assets comprising InnPower's electrical system. The ACA is required as one of the key inputs for the preparation of InnPower's five-year Distribution System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB"). The study's primary objective is to objectively determine the condition of InnPower's assets as a key step in the capital expenditure process for renewal investments. Supplementary objectives include preparing the ACA results to be used for InnPower's upcoming rate filing as well as to continuously improve InnPowers's AM framework.

Scope of the Study

METSCO's work included interviews with InnPower subject matter experts to define the Health Indices appropriate for the asset types, review and consolidation of the client's data sets, analysis of InnPower's asset records to calculate the Health Index values, and preparation of the final document. In total METSCO assessed and calculated Health Index values for the asset classes listed in the table below.

Table 0-1: Asset Classes in Scope

Station Asset Classes	Distribution Asset Classes
Power Transformers	Wood Poles
Power Transformer Tap Changers	Polemount Transformers
Switches	Padmount Transformers
Reclosers	Padmount Switchgear
Service Transformers	SCADA-Mate Switches
Lightning Arresters	Motorized 44kV Switches
Power Fuses	Line Reclosers
Ground Grids	Capacitors
Facilities	

For asset classes with not enough information to calculate health indices for, METSCO created age only assessments to summarize the age profile of those asset classes. The following asset classes are included as part of age assessments but do not have calculated health indices:

- Underground Cables
- Overhead Conductors

All asset condition data used in the study is maintained by InnPower as part of its regular asset management practices. The ACA results are based on condition data recorded by InnPower and its contractors up to the end of October 2021. This information was provided to METSCO between July and October 2021.

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical Health Index ("HI") corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-2 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions required by the asset manager at InnPower.

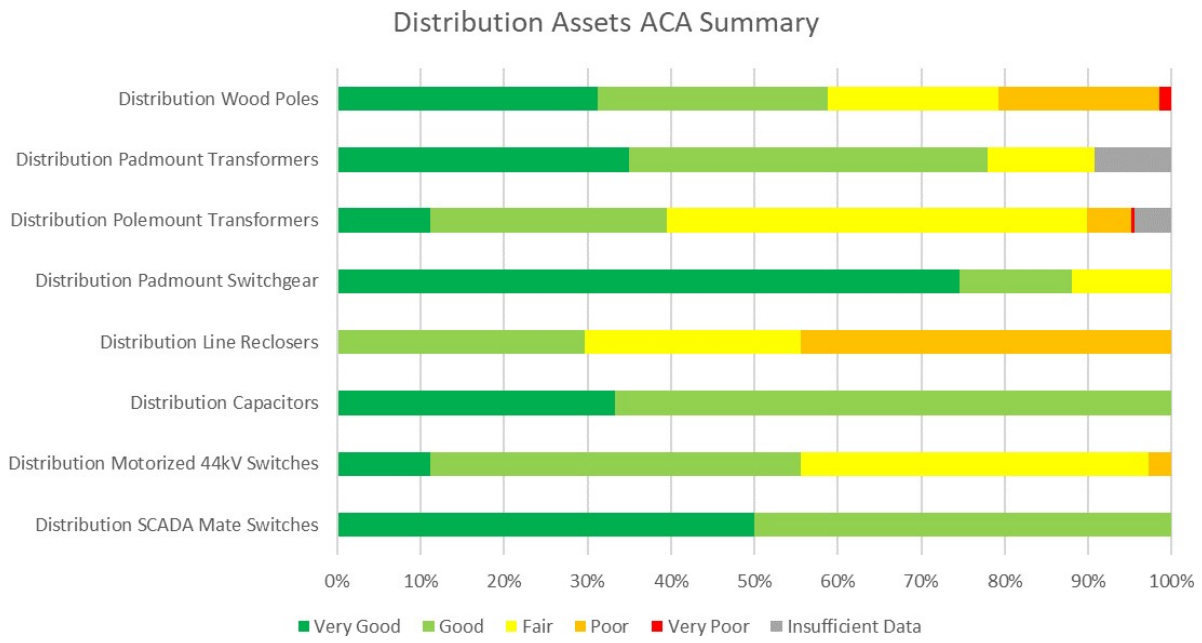
Table 0-2: Health Index Range and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated the HI for every asset in the scope of the assessment using the applicable and available "condition parameters" – individual characteristics of the state of an asset's components. Each condition parameter has its own sub-scale of assessment and a weighting contribution that represents the percentage in the overall HI made up by the particular parameter. METSCO's findings for each asset class were developed using this methodology, as described in more detail in Section 3 and Section 4.

The consolidated results of the ACA for distribution assets are summarized in Figure 0-1. The HI is not calculated for any distribution asset with a Data Availability Indicator ("DAI") less than 70% (i.e., less than 70% of the condition parameters – by weight – are available for that asset).

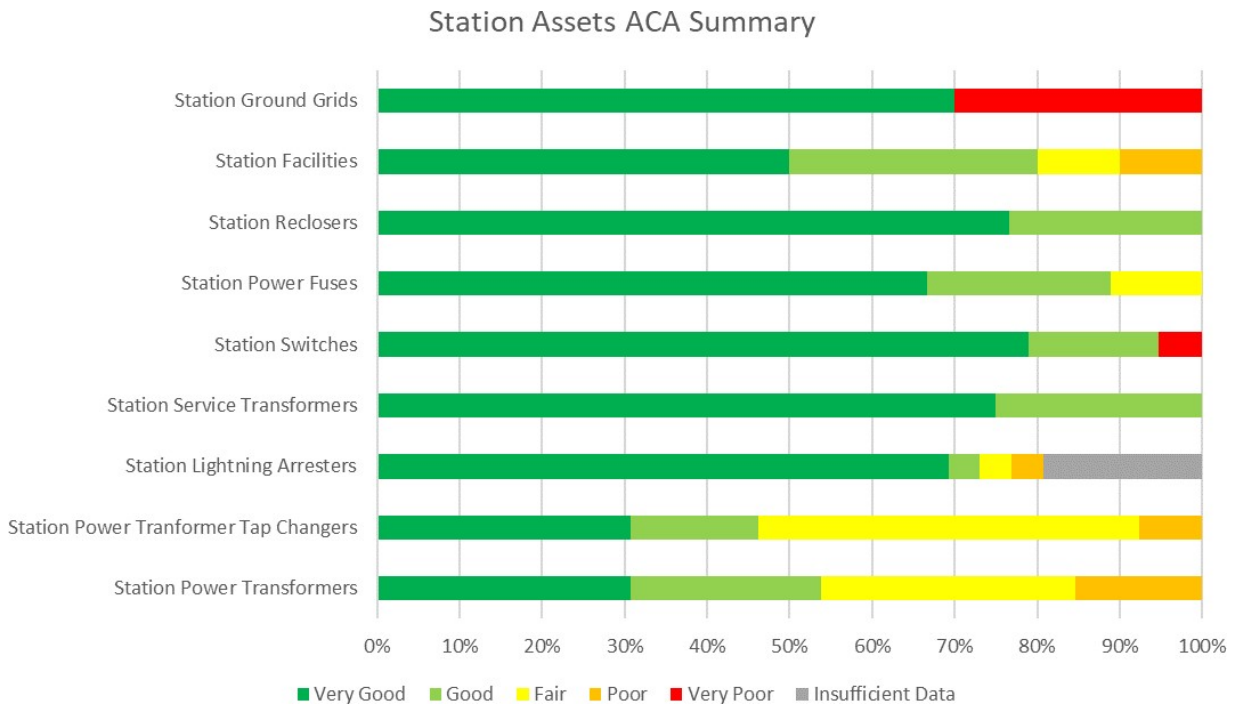
Figure 0-1: Distribution Assets Health Index Results



As Figure 0-1 indicates, the majority of distribution assets are classified in the Very Good or Good condition categories. However, some asset classes, such as Distribution Line Reclosers and Wood Poles, have a significant number of assets in the Poor or Very Poor condition categories. All Poor/Very Poor condition assets carry significant short-term risk, and the utility should apply appropriate asset intervention strategies such as refurbishment or replacement to mitigate this risk. In addition, there is a notable population of assets classified in the Fair condition category for several asset classes such as Polemount Transformers and Distribution Line Reclosers – Fair condition assets will require intervention over the long-term and may require intervention in the short-term depending on asset criticality.

Figure 0-2 summarizes the ACA results for InnPower's station assets. The HI is not calculated for any station asset with a Data Availability Indicator ("DAI") less than 60% (i.e., less than 60% of the condition parameters – by weight – are available for that asset).

Figure 0-2: Station Assets Health Index Results



As Figure 0-2 indicates, the majority of station assets are assessed to be in a healthy state as they are classified in the Very Good or Good condition categories. However, there is a small population of assets in specific asset classes that are assessed to be in Poor or Very Poor condition. As outlined above, these assets will require short-term asset intervention in the next five years as they likely carry significant failure risk. In addition, several asset classes include a subset of units classified in the Fair condition category. Given that certain station asset classes are critical to the overall distribution system (e.g., Power Transformers), the utility should monitor these assets for signs of accelerated degradation as they may degrade to Poor or Very Poor condition over the next five to ten years.

Table 0-3 presents the numerical HI summary for each asset class. The HI distribution is based on the total population count of a given asset class. For each asset class, the population, average HI, average DAI, and HI distribution are listed.

Table 0-3: Asset Condition Assessment Overall Results

Asset Class	Population	Health Index Distribution						Average HI	Average DAI
		Very Good	Good	Fair	Poor	Very Poor	No HI		
Distribution Assets									
SCADA Mate Switches	6	3	3	-	-	-	-	78%	100%
Motorized 44kV Switches	36	4	16	15	1	-	-	70%	100%
Capacitors	9	3	6					79%	100%
Line Reclosers	27	-	8	7	12	-	-	58%	100%
Padmount Switchgear	67	50	9	8	-	-	-	87%	100%
Polemount Transformers	2,177	244	615	1,096	117	7	98	69%	98%
Padmount Transformers	1,478	517	635	189	1	-	136	83%	97%
Wood Poles	10,044	3,131	2,771	2,054	1,946	142	-	70%	100%
Station Assets									
Power Transformers	13	4	3	4	2	-	-	73%	94%
PTX Tap Changers	13	4	2	6	1	-	-	71%	100%
Lightning Arresters	26	18	1	1	1	-	5	94%	93%
Service Transformers	12	9	3	-	-	-	-	90%	100%
Switches	38	30	6	-	-	2	-	90%	91%
Power Fuses	9	6	2	1	-	-	-	90%	85%
Reclosers	30	23	7	-	-	-	-	89%	100%
Facilities	10	5	3	1	1	-	-	79%	96%
Ground Grids	10	7	-	-	-	3	-	70%	100%

InnPower's Current Health Index Maturity and Continuous Improvement

Overall, InnPower's asset data collection practices are sufficiently robust to enable calculation of the recommended ACA that is consistent with industry best practices. The average DAI scores are very high across most asset classes and meet the DAI threshold requirement in most cases. The only exception is the Station Lightning Arresters asset class which had a subset of units for which an HI score could not be calculated or extrapolated. Both distribution transformer asset classes also contained some units for which a condition assessment could not be completed. However, the size of these asset classes was sufficiently large to extrapolate the available HI demographics to the entire population. In addition, the Underground Cables and Overhead Conductors asset classes had no condition assessment data – therefore, these assets were assessed solely on the basis of age.

While the HIF formulation and DAI have been determined based on available condition parameters, there are opportunities for InnPower to introduce additional variables that can provide further insight into the degradation level of a given asset class. For example, visual inspection results would aid the assessment of Station Capacitors and age data would enable a more complete analysis for the Station Switches asset class. These recommendations are covered in detail in Section 6.

In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of aging infrastructure, changing climate, evolving customer needs, and many other priorities. As such, an adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations. METSCO makes this observation to highlight its position that the sole fact of a gap between a utility's current process state and the industry best practices need not necessarily indicate that an action to remedy that gap is required in short order.

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1 Introduction

METSCO Energy Solutions Inc. ("METSCO") is an industry expert in Asset Condition Assessment ("ACA") and Asset Management ("AM") practices due to our extensive experience in conducting ACAs, developing AM plans, and implementing AM frameworks for transmission and distribution utilities across North America. METSCO's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions. A selection of METSCO's past projects is attached as Appendix A to this report.

InnPower Corporation ("InnPower") is an electricity distributor operating in the regions of Innisfil and South Barrie. InnPower engaged METSCO to prepare a comprehensive ACA study for the assets comprising InnPower's electrical system. The ACA is required as one of the key inputs for the preparation of InnPower's five-year Distribution System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB"). The study's primary objective is to objectively determine the condition of InnPower's assets as a key step in the capital expenditure process for renewal investments. Supplementary objectives include preparing the ACA results to be used for InnPower's upcoming rate filing as well as to continuously improve InnPowers's AM framework.

A unique ACA methodology is applied to each asset class deployed within InnPower's system. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections, and recording of asset condition to identify the assets most at risk at reaching the end-of-life criteria over the planning horizon. Each criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life. The assets covered in the report include the major asset classes listed in the table below.

Table 1-1: Asset Classes in Scope

Station Asset Classes	Distribution Asset Classes
Power Transformers	Wood Poles
Power Transformer Tap Changers	Underground Cables
Switches	Overhead Conductors
Reclosers	Polemount Transformers
Service Transformers	Padmount Transformers
Lightning Arresters	Padmount Switchgear
Power Fuses	SCADA-Mate Switches
Ground Grids	Motorized 44kV Switches
Facilities	Line Reclosers
	Capacitors

All the asset condition data is maintained by InnPower as part of its regular AM and maintenance practices. All condition information was collected by InnPower and its contractors up to the end of October 2021. This data was transmitted to METSCO between July and October 2021 to complete the ACA.

The report is organized into six sections including this introductory section:

- Section 2 summarizes the ISO 5500X AM standards, discusses how the ACA fits into the overall AM framework; and provides an overview of METSCO's ACA methodology;
- Section 3 summarizes the asset Health Index ("HI") calculation methodology;
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes;
- Section 5 provides METSCO's conclusions; and
- Section 6 summarizes METSCO's recommendations for InnPower on data collection improvements for continuous improvement efforts for the ACA.

2 Context of the ACA within AM Planning

The ACA is a key step in developing an asset replacement strategy. By evaluating the current set of available data related to the condition of in-service assets comprising an organization's asset portfolio, condition scores for each asset are determined. The ACA involves the collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA is designed to provide insights into the current state of an organization's asset base, the risks associated with identified degradation, approaches to managing this degradation within the current AM framework, and how to best make use of these results to extract the optimal value from the asset portfolio going forward.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous improvement stage - those looking to assess and progressively enhance an AM system already in place for avenues of improvement.

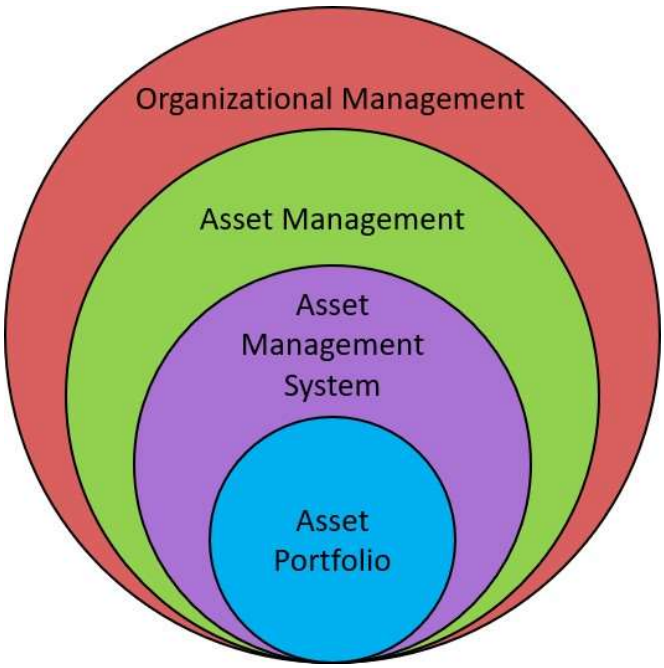
Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

[1] ISO 55000 – Asset management – Overview, principles and terminology

An asset is any item or entity that has a value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (e.g., public safety). The hierarchy of an AM framework begins with the asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. The ACA is the procedure to turn the known condition information into actionable insights based on the level of deterioration.

Around the asset portfolio, the AM system operates and represents a set of interacting elements that establish the policy, objectives, and processes to achieve those objectives. The AM system is encompassed by the AM practices – coordinated activities of the organization to realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy.[1]

Figure 2-1: Relationship between Key AM Terms [1]



2.2 ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to the collection and storage of technical specifications, historical asset

performance, projected asset behaviour and degradation, the configuration of an asset or asset-group within the system, the operational relationship of one asset to another, etc. In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process it to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to best AM practices being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 55002 states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented.[2] The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact in the decision-making process.

2.3 Continuous Improvement in the AM Process

The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated compliance among the asset base, increased public and worker safety, and corporate sustainability.[1]

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical experts, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization as a whole. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, in order to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[1]

AM should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

3 Asset Condition Assessment Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing the ACA study can be is a four-phase procedure:

1. *Initial information gathering* – including initial interviews with InnPower staff to investigate AM practices and establish the range of available condition data sources the asset classes within the scope of this project. In addition, subsequent interviews with InnPower subject matter experts were used to confirm key assumptions regarding the condition assessment methodology.

2. *Database construction* – activities to construct a single database of condition-related information for each InnPower asset class using the provided data sources. This includes consolidation of InnPower's asset inspection records, databases containing results of technical tests performed by InnPower contractors, and any relevant databases such as the Geographic Information System ("GIS").

3. *HI and Data Availability Index calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from InnPower to improve the accuracy of the asset health calculation ifapplicable.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3.2 Data Sources

To assess the demographics and establish the unit population of InnPower's system assets, METSCO was provided with InnPower's asset demographic data from its current databases such as the Geographic Information System ("GIS"). These data came from InnPower's corporate asset registries containing information on asset vintage, model, and year of commissioning. The database served as the primary asset library that contained asset nameplate information such as age and unique identifiers.

To assess the condition of InnPower's system, METSCO was provided with available asset inspection and maintenance data for the asset classes in scope. Various sources hold records of InnPower's inspection and maintenance activities. Most of these data came from

primary sources such as equipment inspection forms completed by InnPower's staff or contractors, or the results of specific tests such as the Dissolved Gas Analysis ("DGA") for station power transformer oil.

Additionally, METSCO was provided with historical operating data for assets that require operating information for the HI calculation. An example of operating data used is the historical loading information for transformers.

3.3 Asset Condition Assessment Methodologies

Prior to completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. Additive models – asset degradation factors and scores are used to independently calculate a score for each individual asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. Gateway models – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. Subtractive models – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. Multiplicative models – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. In general, most distribution utilities employ an additive model. METSCO selected this approach when conducting the ACA, which is in alignment with most of InnPower's peer utilities.

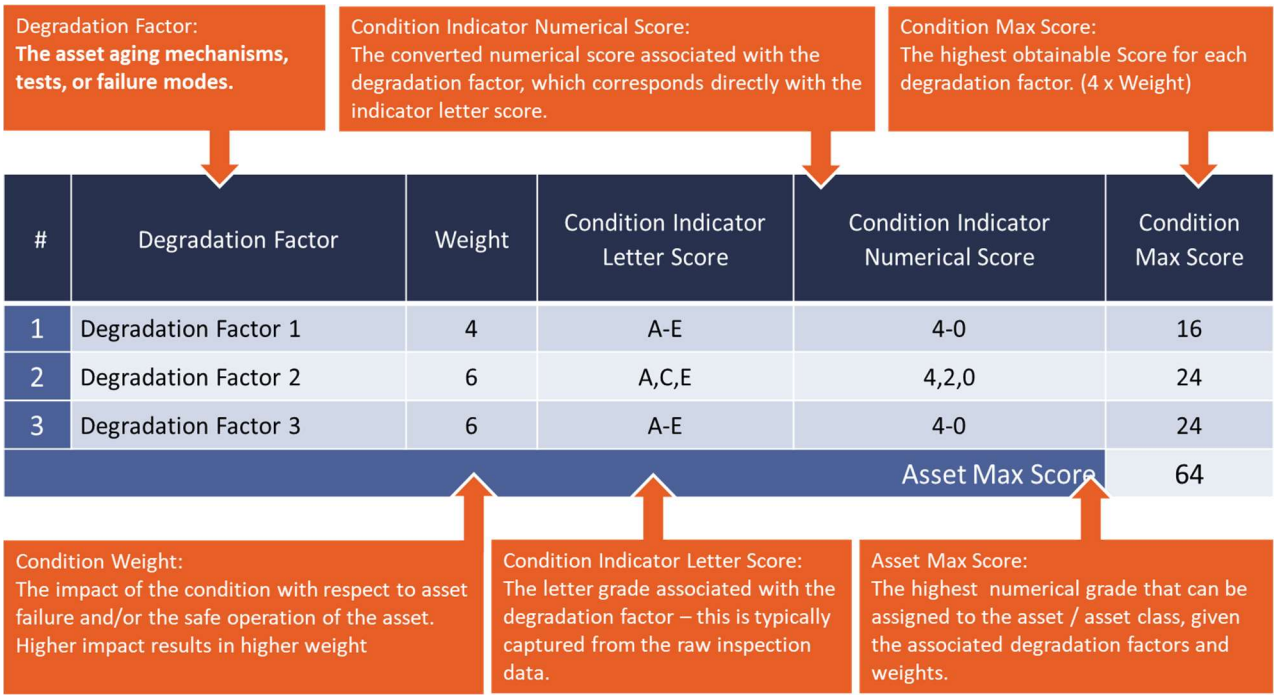
3.4 Overview of Selected Methodology

3.4.1 Condition Parameters

To calculate the HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that asset. A

weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1 exemplifies an HI formulation table.

Figure 3-1: HI Formulation Components



#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-condition parameters such as the acidity of the oil, its interfacial tension, dielectric strength, and water content.

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4 Best Condition

B – 3 Normal Wear

C – 2 Requires Remediation

D – 1 Rapidly Deteriorating

E – 0 Beyond Repair

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

While some assets lose their structural integrity faster than would be expected with the passage of time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period of time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, METSCO limits the instances where it relies on only age as a parameter explicitly incorporated into the HI formulation. In some cases, however, the limited number of condition parameters available for calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing condition of complex equipment containing a number of internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

3.4.3 Final Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through identification of condition parameters acknowledged to be critical indicators of overall asset health.

3.4.4 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time. Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing, or replacing the asset prior to failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available to the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number and *α* is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are assigned an extrapolated HI value using the valid HI results for assets within the same asset class and ten-year age band. Similarly for station assets – typified by relatively small asset populations – if the DAI for an asset is less than 60%, a valid HI cannot be calculated. HI results for station assets are not extrapolated due to the small population.

4 Health Index Formulations and Results

This section presents the developed HI formulation for each asset class, the calculated scores for HI results, and the data available to perform the study.

4.1 Distribution Assets

4.1.1 Wood Poles

Wood poles are an integral part of any distribution system. They are the support structures for the overhead distribution system. The HI for Wood Poles is calculated by considering a combination of end-of-life criteria summarized in Table 4-1.

Table 4-1: Wood Pole HI Formulation

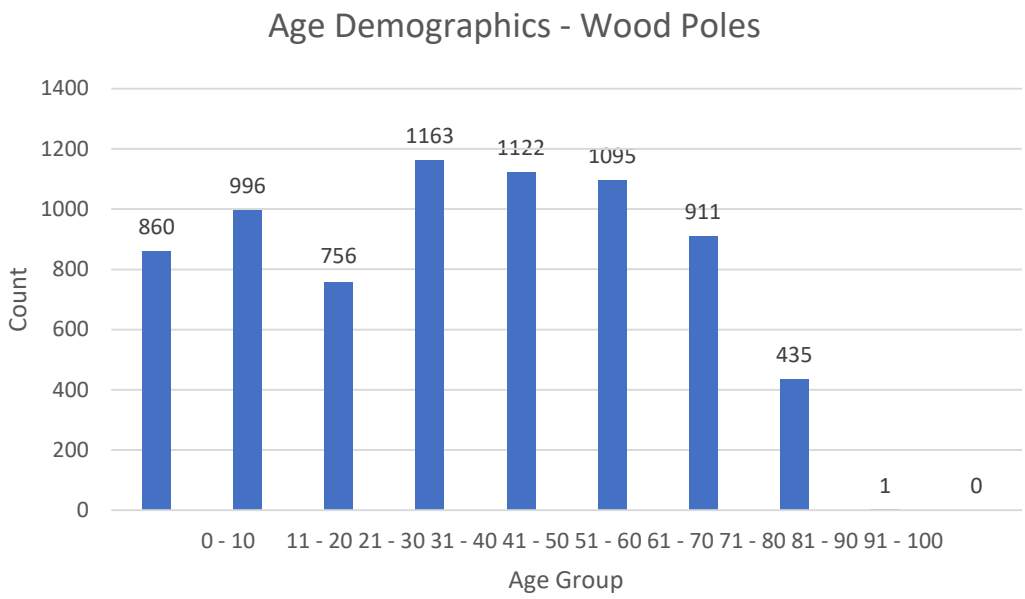
Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	10	A, B, C, D, E	4, 3, 2, 1, 0	40
Pole Top Condition	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Shell Condition	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Cross Arm Condition	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Insects Damage Condition	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Woodpecker Damager	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Remaining Strength	20	A, B, C, D, E	4, 3, 2, 1, 0	80
Treatment Type	5	A, B, C, D, E	4, 3, 2, 1, 0	20
Total Score				180

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage, and weather effects which can impact the mechanical strength of the pole. Any loss in the strength of the pole can present additional safety and environmental risks to the public and to InnPower field staff. The remaining strength condition parameter is a quantitative measurement that provides adequate evidence of the deterioration of the operational health of the asset.

Asset data was provided for a total of 7,339 Wood Poles, however InnPower owns a total of 10,043 units. The age distribution for this class is presented below in Figure 4-1. The estimated Typical Useful Life ("TUL") value for this asset class is 45 years – this reveals some

risk as there are currently at least 2,442 (or 3,341, if extrapolated) Wood Poles that are beyond this threshold and another 1,122 (or 1,535, if extrapolated) Wood Poles that will exceed the TUL in five to ten years.

Figure 4-1: Wood Poles Age Distribution



The condition assessment results are presented in Figure 4-2 below – these quantities are based on the population for which asset data was provided. The Wood Poles asset class has a significant proportion of units in poor condition as 21% of the population falls into the Poor or Very Poor category. This aligns with the implications of the age demographics presented above. These assets likely require short-term intervention through asset replacement or refurbishment to maintain system safety and reliability. In addition, 20% of population is in the Fair condition category – this subset of assets may degrade to Poor or Very Poor condition and require asset intervention over the long term or short term (depending on asset criticality). Figure 4-3 below presents the results of the condition assessment extrapolated to the entire population of 10,043 Wood Poles.

Figure 4-2: Wood Poles Health Index Distribution

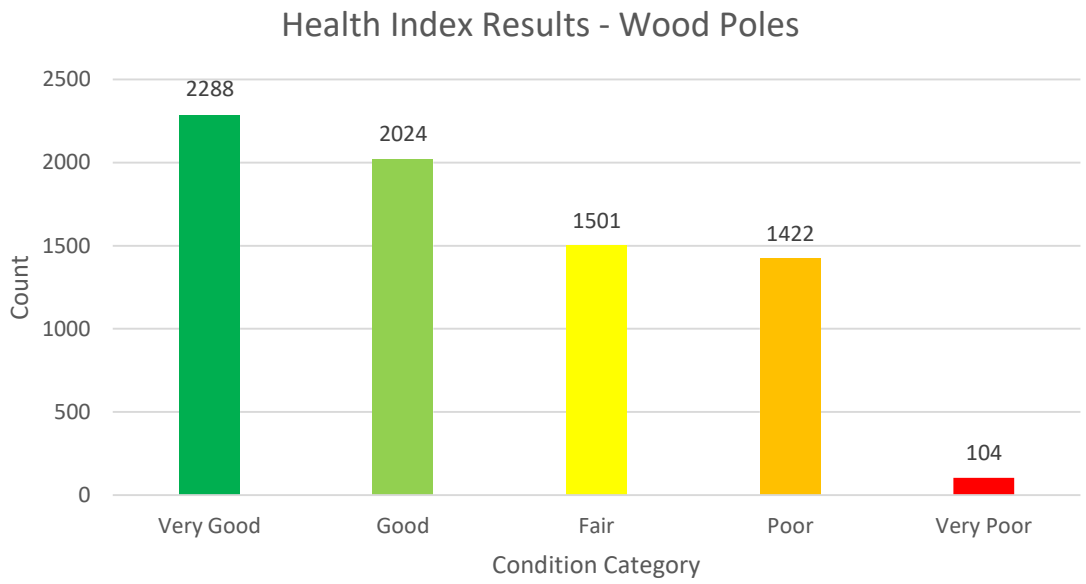
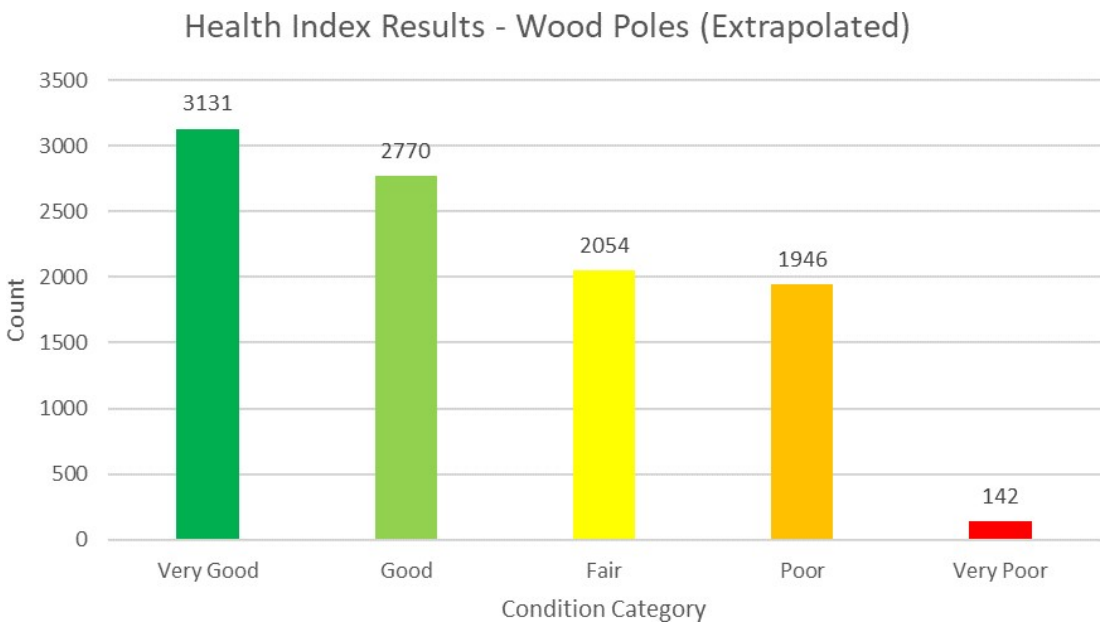


Figure 4-3: Wood Poles Health Index Distribution (Extrapolated)



4.1.2 Underground Cables

At the time of completion of this condition assessment, this asset class was affected by data limitations. A complete condition assessment was not completed for this asset class as only age data was available. In addition, it is important to note that the data source for the Underground Cables age data may be affected by quality and accuracy issues and it is advised that the utility reviews and updates this information as soon as possible. InnPower currently has 173km of underground cable in its system. The current age demographics for this asset class are presented in Figure 4-4 and Table 4-2 below.

The estimated TUL for this asset class is 40 years. As shown in the table below, there are currently 8.8km of Underground Cable (5% of the population) that have exceeded this threshold and may carry short-term failure risk. These assets should be investigated, and the utility should take the appropriate asset intervention action (i.e., replacement or refurbishment) to mitigate this risk. In addition, there are 32.9km of Underground Cable (19% of the population) that will exceed the TUL over the next ten years. These assets should be monitored for signs of additional degradation as they may experience an increase in failure risk over the next five to ten years. Overall, the age demographics indicate that this asset class is in good condition as 131.3km of underground cable (76% of the population) have yet to approach the TUL threshold.

Figure 4-4: Underground Cables Age Distribution

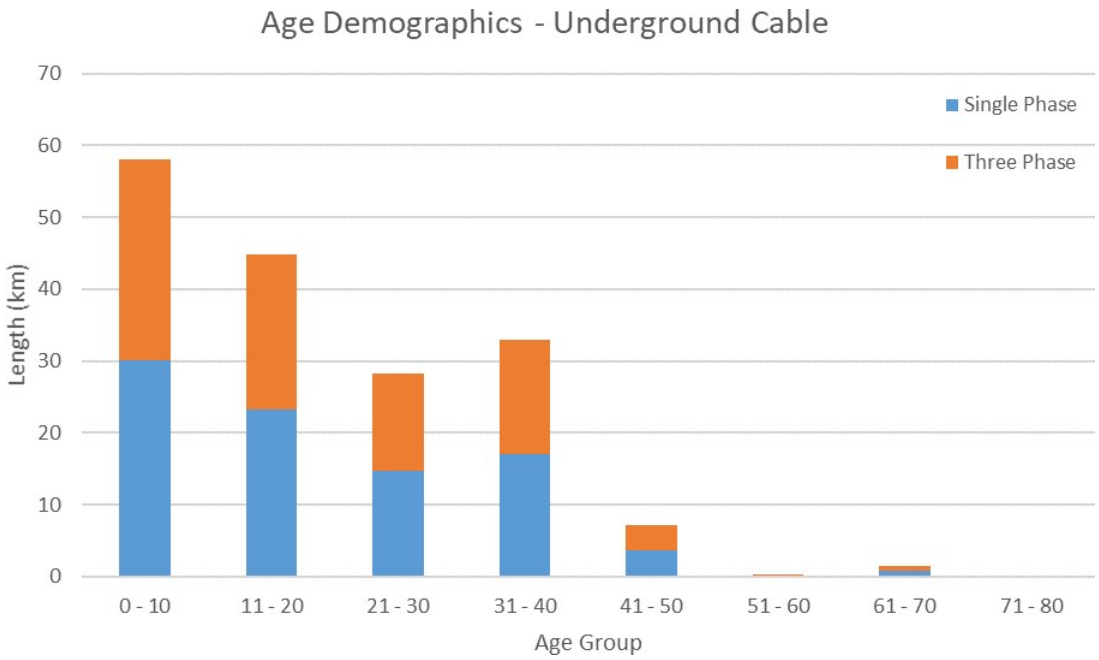


Table 4-2: Underground Cables Age Distribution

Age Group	0 - 10	11 - 20	21 - 30	31 - 40	41 - 50	51 - 60	61 - 70	71 - 80
Single Phase (km)	30.1	23.3	14.7	17.1	3.7	0.2	0.7	0.0
Three Phase (km)	28.0	21.6	13.6	15.8	3.4	0.2	0.7	0.0
Total (km)	58.1	44.9	28.3	32.9	7.1	0.3	1.4	0.0

4.1.3 Overhead Conductors

At the time of completion of this condition assessment, this asset class was affected by data limitations. A complete condition assessment was not completed for this asset class as only age data was available. In addition, it is important to note that the data source for the Overhead Conductors age data may be affected by quality and accuracy issues and it is advised that the utility reviews and updates this information as soon as possible. InnPower currently has 660km of Overhead Conductor in its system. The current age demographics for this asset class are presented in Figure 4-5 and Table 4-3 below.

The estimated TUL for this asset class is 60 years. As shown in the table below, there are currently 193.1km of Overhead Conductor (29% of the population) that have exceeded this threshold and may carry short-term failure risk. These assets should be investigated, and the utility should take the appropriate asset intervention action (i.e., replacement or refurbishment) to mitigate this risk. In addition, there are 78.3km of Overhead Conductor (12% of the population) that will exceed the TUL over the next ten years. These assets should be monitored for signs of additional degradation as they may experience an increase in failure risk over the next five to ten years. Overall, the age demographics indicate that this asset class is in good condition as 388.6km of Overhead Conductor (59% of the population) have yet to approach the TUL threshold.

Figure 4-5: Overhead Conductor Age Distribution

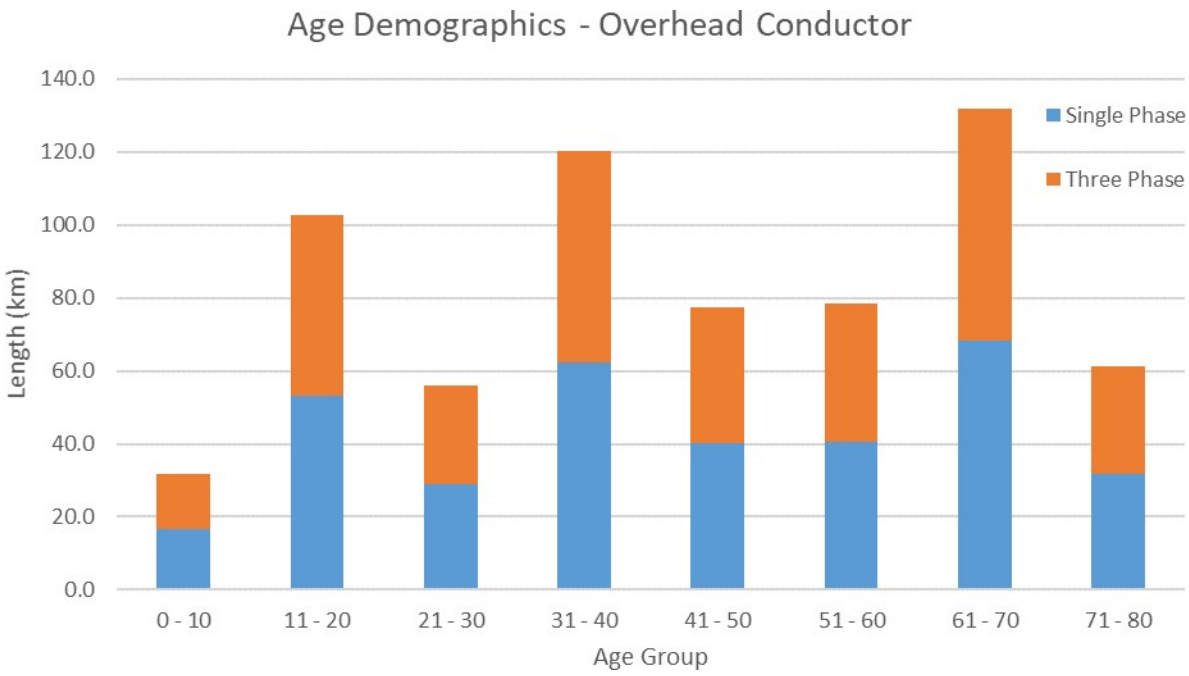


Table 4-3: Overhead Conductor Age Distribution

Age Group	0 - 10	11 - 20	21 - 30	31 - 40	41 - 50	51 - 60	61 - 70	71 - 80
Single Phase (km)	16.6	53.2	29.1	62.4	40.2	40.6	68.4	31.7
Three Phase (km)	15.4	49.4	27.0	57.9	37.4	37.7	63.5	29.5
Total (km)	31.9	102.7	56.1	120.2	77.6	78.3	131.9	61.2

4.1.4 Distribution Pole Mount Transformers

InnPower owns 2,177 Distribution Polemount Transformers within its service territory. Distribution Transformers are installed on service poles above ground with the primary function to step down power from the medium voltage distribution system to the voltage for customer use. Distribution Polemount Transformers are assessed by considering a combination of degradation factors summarized in Table 4-4.

Table 4-4: Distribution Pole Mount Transformer Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Average Loading	1	A, B, C, D, E	4, 3, 2, 1, 0	4
IR Scanning	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Total Score				12

Figure 4-6 below presents the age demographics for this asset class. Given that the estimated TUL for this asset class is 40 years, it is evident that some risk exists as there are 677 units (31% of the population) currently beyond this threshold. There are an additional 683 units (32% of population) that will exceed this TUL in the next five to ten years. These insights align with the results of the condition assessment presented in Figure 4-7 below. This figure shows that 859 units are in the Good or Very Good condition. A further 1096 (50% of population) of the Polemount Transformers asset class is in Fair condition category that may degrade to Poor or Very Poor condition and require asset intervention over the long-term. There were 98 units for which there was insufficient data for the calculation of a health index score – an extrapolation was performed to estimate the condition of these units. The results of this extrapolation are presented in Figure 4-8 below.

Figure 4-6: Distribution Pole Mount Transformer Age Distribution

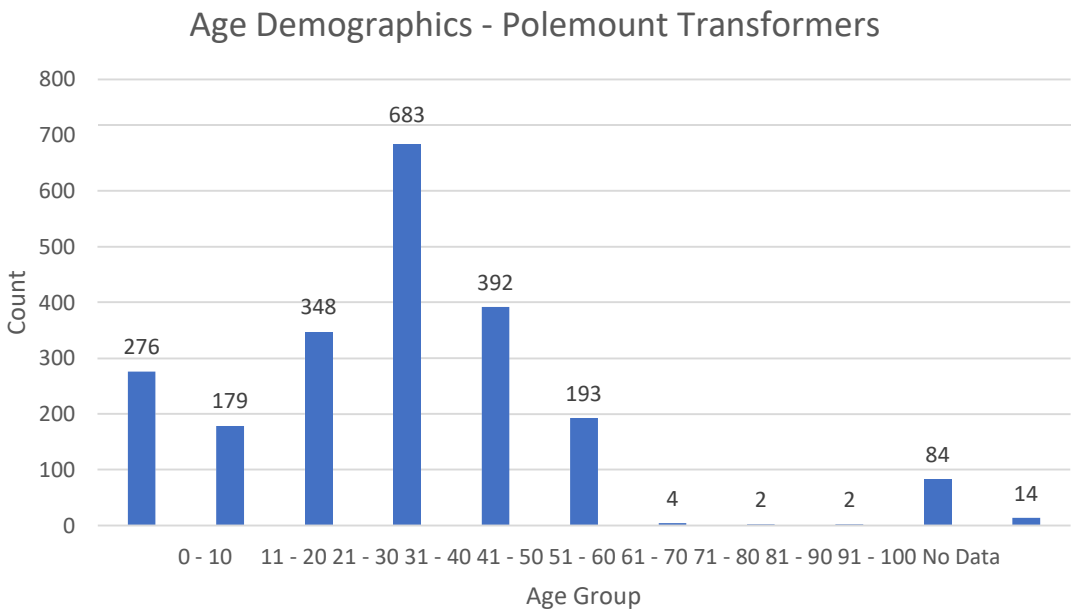


Figure 4-7: Pole Mount Distribution Transformer HI Results

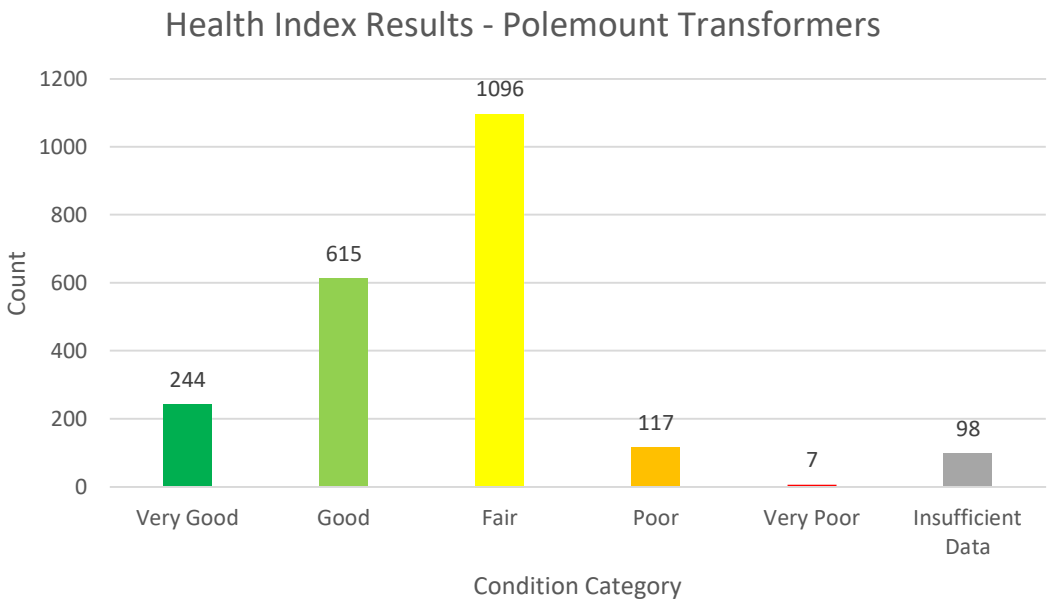
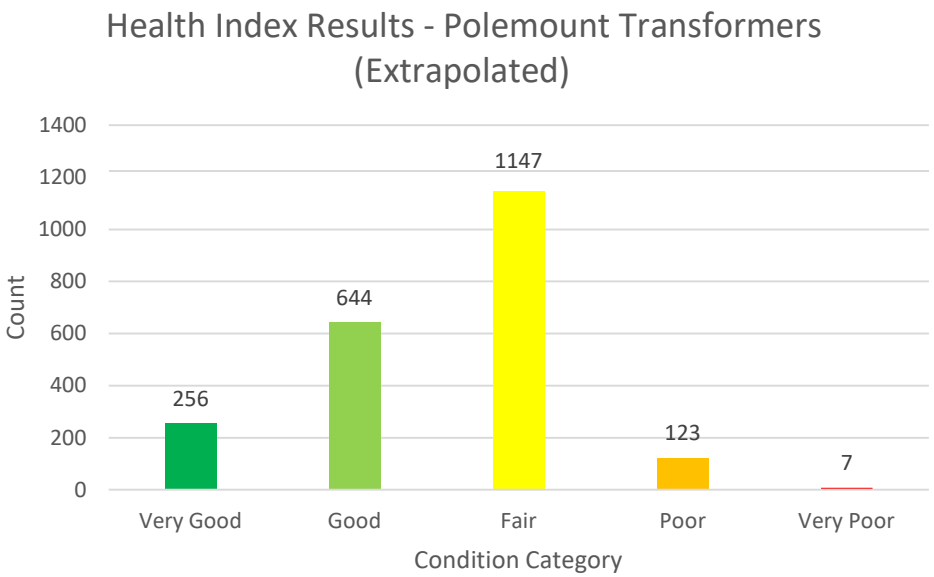


Figure 4-8: Pole Mount Distribution Transformers HI Results (Extrapolated)



4.1.5 Distribution Pad Mount Transformers

Distribution Pad Mount Transformers are utilized for similar functionalities as pole mount transformers. They step down power from the medium voltage distribution system to the final utilization voltage for the customer. However, Pad Mount transformers are located below ground in the underground distribution system. The condition assessment methodology for this asset class is presented in Table 4-5. In addition to service age, IR Scanning is considered in the assessment. IR hotspots can indicate a fault occurring in the transformer that may reduce the useful life of the transformer.

Table 4-5: Distribution Pad Mount Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Average Loading	1	A, B, C, D, E	4, 3, 2, 1, 0	4
IR Scanning	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Total Score				12

InnPower owns 1,478 pad mount transformers within its service area. The age distribution for this asset class is provided in Figure 4-9 below. The estimated TUL for this asset class is

40 years, meaning that only 5% of the population is currently beyond this threshold. However, there are an additional 284 units or 19% of the population that will exceed the TUL in the next five to ten years. The condition assessment results for this asset class are presented in Figure 4-10 below. A large portion of the asset class is in a healthy state as 78% of the population is classified in the Very Good or Good condition category, and only one asset being in the Poor or Very Poor condition. In addition, there are 189 units in the Fair condition category that should be monitored as they may degrade to Poor or Very Poor condition over the long-term. There were 136 units for which there was insufficient data for the calculation of a health index score – an extrapolation was performed to estimate the condition of these units. The results of this extrapolation are presented in Figure 4-11 below.

Figure 4-9: Distribution Pad Mount Transformer Age Distribution

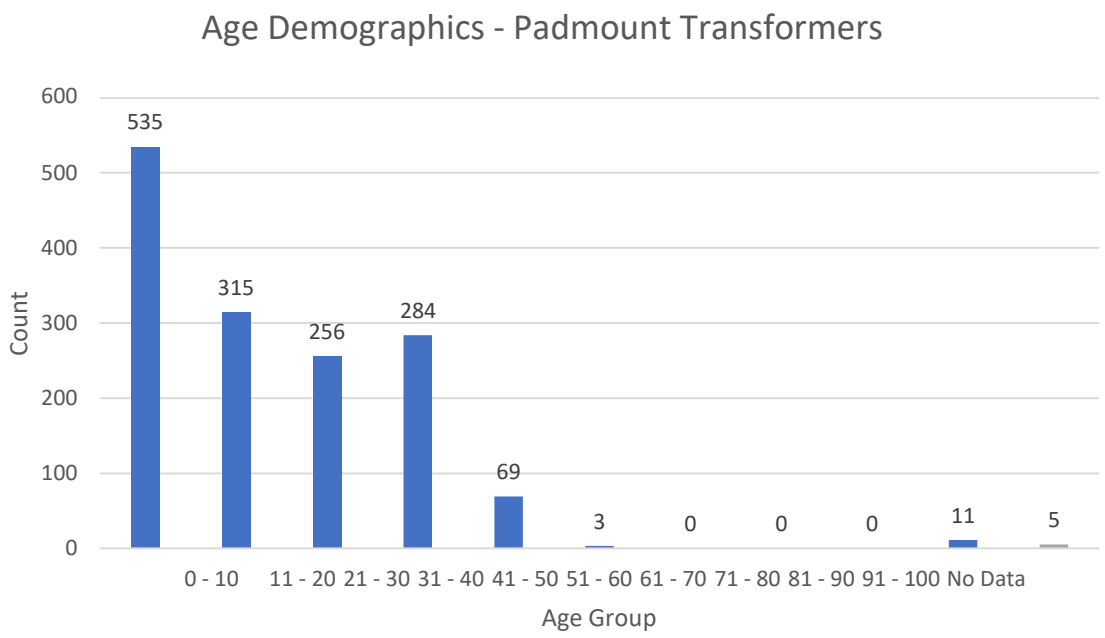


Figure 4-10: Distribution Pad Mount Transformer HI Results

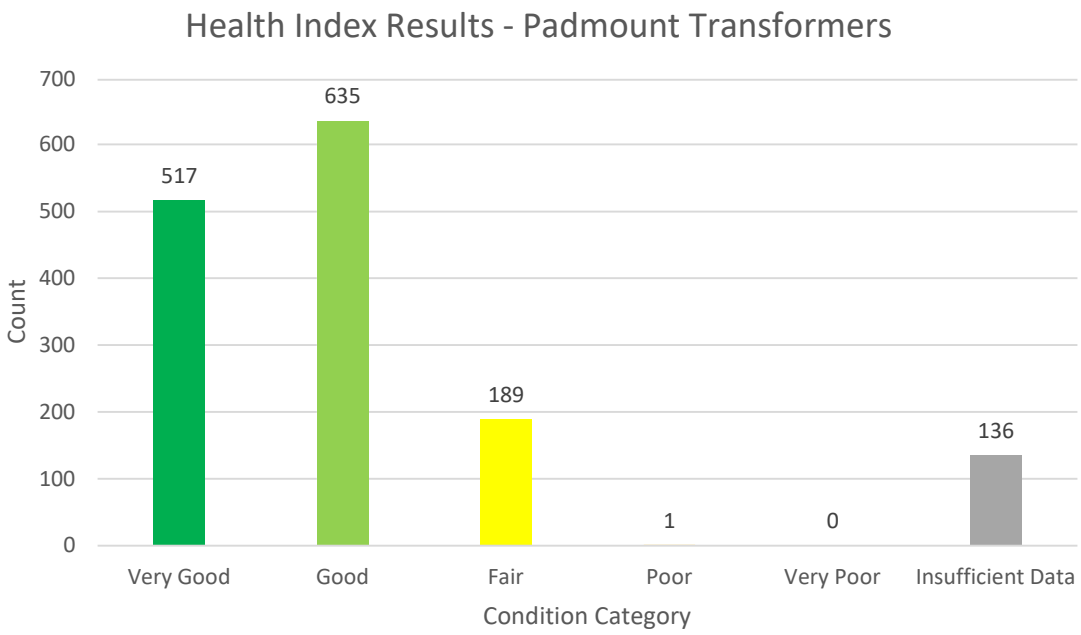
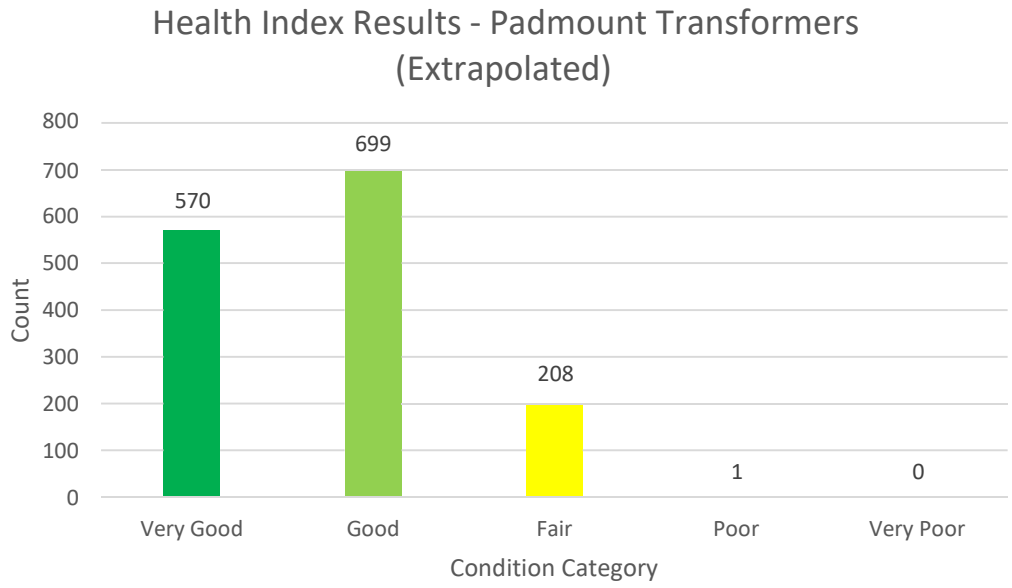


Figure 4-11: Distribution Pad Mount Transformer HI Results (Extrapolated)



4.1.6 Distribution Pad Mount Switchgear

Distribution switchgears provide the required level of operating flexibility. They are employed for controlling, regulating, and isolating the electrical circuit in the distribution system. During a fault, the switchgear isolates and clears the faults downstream. It also de-energizes equipment during maintenance and testing. They are used to transfer power manually or automatically in distribution circuits from a preferred source to an alternate source. The condition assessment methodology for this asset class is presented in Table 4-6 below.

Table 4-6: Distribution Switchgear HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	5	A, B, C, D, E	4, 3, 2, 1, 0	20
IR Scanning	5	A, B, C, D, E	4, 3, 2, 1, 0	20
Total Score				40

InnPower owns 67 Pad Mount Switchgears within its service territory. The age demographics for this asset class are presented in Figure 4-12 below. The TUL for this asset class is estimated to be 30 years, meaning that the current age demographics indicate that most of the assets (88%) are below this threshold. The condition assessment results are presented in Figure 4-13 below. Overall, this asset class is in a healthy state as most units (88% of the population) are classified in the Good condition or higher. InnPower should investigate the 8 units that are currently classified in the Fair condition category as these assets may degrade to Poor or Very Poor condition over the next five to ten years.

Figure 4-12: Distribution Padmount Switchgear Age Distribution

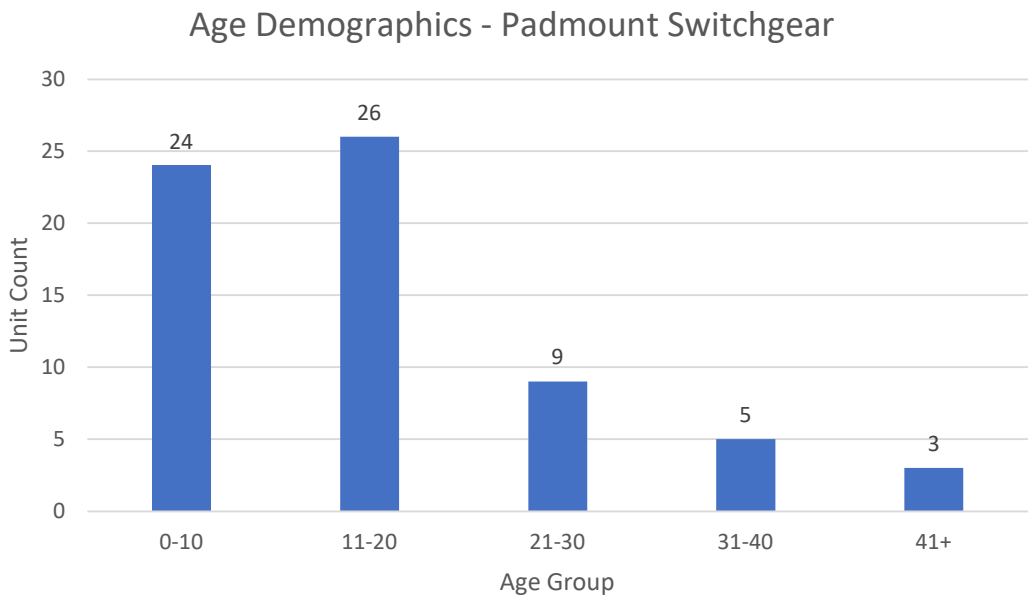
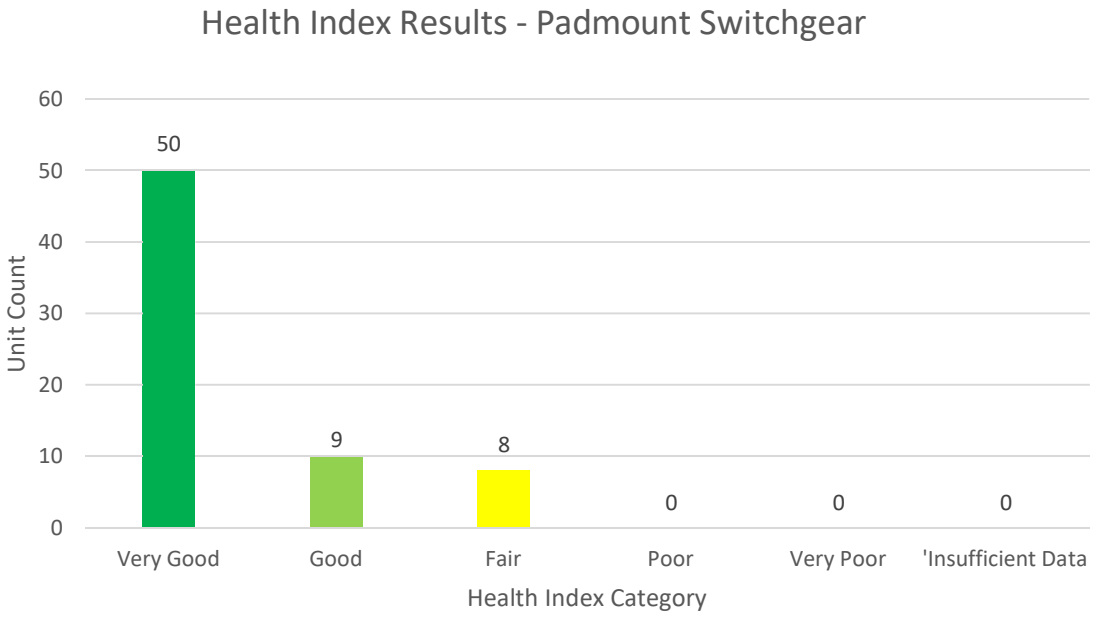


Figure 4-13: Distribution Pad Mount Switchgear HI Results



4.1.7 SCADA-Mate Switches

SCADA-Mate switches are a sub class of distribution switches that are integrated with the SCADA system and provide a range of functions such as remote fault isolation and service restoration. The condition assessment methodology for this asset class is presented in Table 4-7 below.

Table 4-7: SCADA-Mate Switches HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	3	A, B, C, D, E	4, 3, 2, 1, 0	12
IR Scanning	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Total Score				20

InnPower currently deploys six SCADA-Mate in its distribution system. The age demographics for this asset class are presented in Figure 4-14 below. The expected TUL for this asset class is 45 years – based on the available age data, all units are well below this threshold. This is also reflected in the results of the condition assessment presented in Figure 4-15 as all units are classified in the Very Good or Good condition category, and this asset class is in excellent condition based on the available data.

Figure 4-14: SCADA-Mate Switches Age Distribution

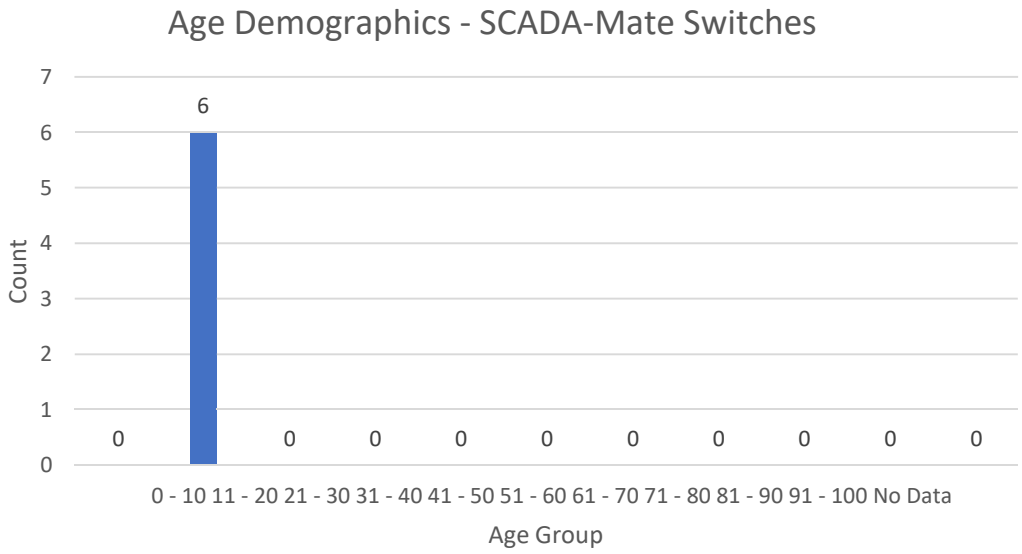
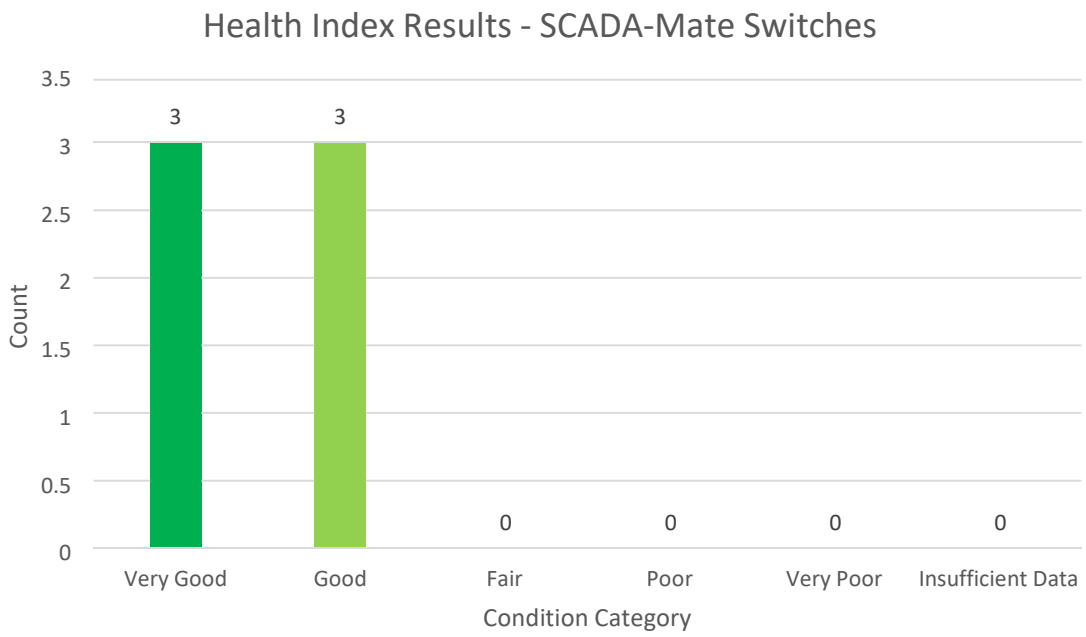


Figure 4-15: SCADA-Mate Switches HI Results



4.1.8 Motorized 44kV Switches

Motorized 44kV switches are a sub class of distribution switches that are suited to line, transformer, and cable switching functions. The condition assessment methodology for this asset class is presented in Table 4-8 below.

Table 4-8: Motorized 44kV Switches HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	3	A, B, C, D, E	4, 3, 2, 1, 0	12
IR Scanning	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Visual Inspection	3	A, B, C, D, E	4, 3, 2, 1, 0	12
Total Score				32

InnPower has 36 Motorized 44kV switches in its distribution system – the age demographics for this asset class are presented in Figure 4-16 below. The TUL for this asset class is estimated to be 45 years, meaning that the current age demographics indicate that all assets are well below this threshold. The condition assessment results are presented in

Figure 4-17 below. Overall, this asset class is in an acceptable state as the majority of units (56% of the population) are classified in the Very Good or Good condition categories. While there is a significant population of units in the Fair condition category (42% of the population) that may deteriorate to Poor condition or worse, there is only one unit currently in the Poor condition category.

Figure 4-16: 44kV Motorized Switches Age Distribution

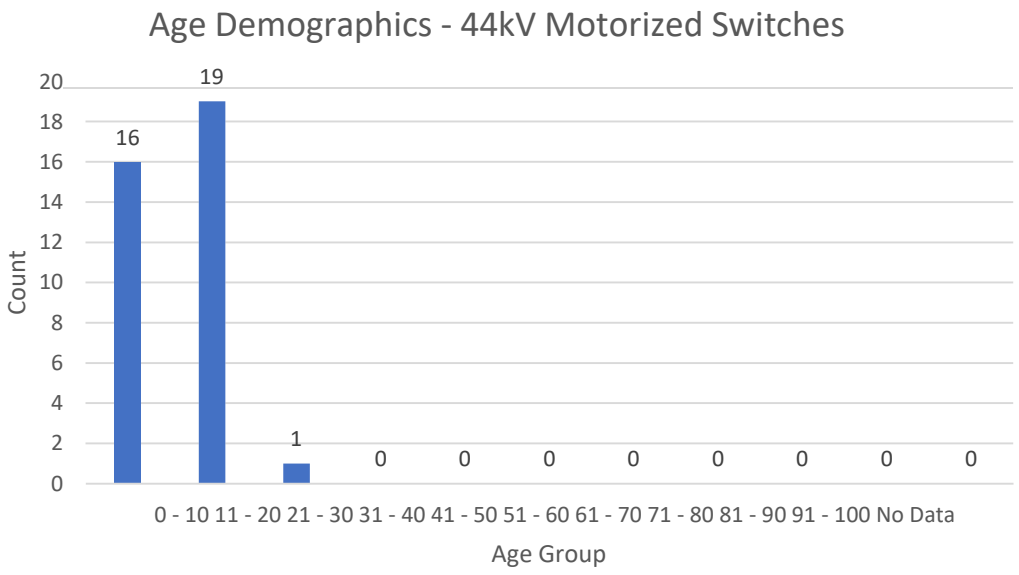
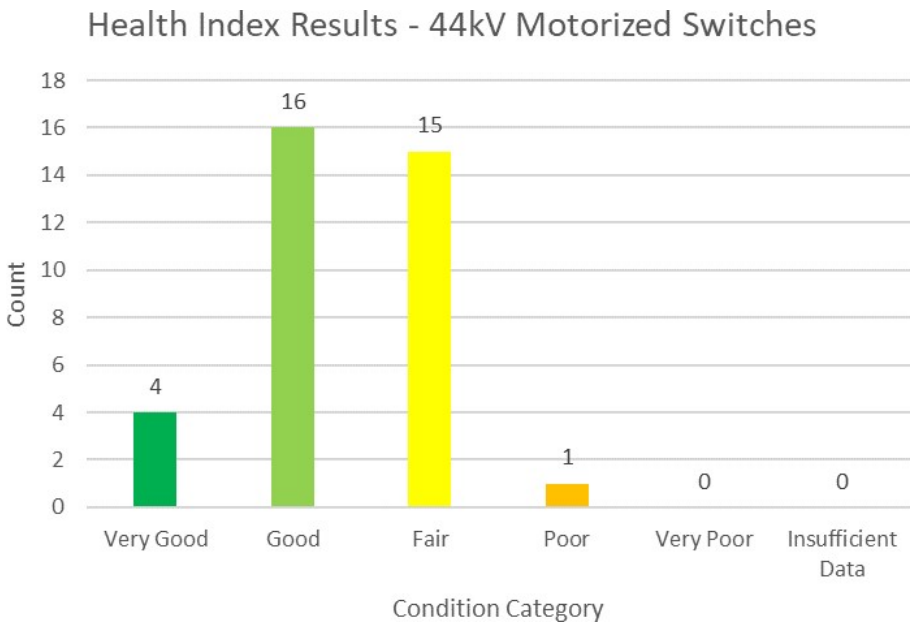


Figure 4-17: 44kV Motorized Switches HI Results



4.1.9 Line Reclosers

A line recloser is a type of automatic electric switch that can detect and interrupt momentary faults in the distribution network. They have the ability to restore service if the detected faults are confirmed to be momentary – alternatively, if permanent faults are discovered, the recloser will remain open until the underlying problem is resolved. These features enable efficient operations as they can minimize the scope of an outage and work crews are not required to manually reset the unit in the case of a momentary fault. Line reclosers are subject to degradation factors such as ageing (i.e., wear and tear over normal lifetime operation), environmental conditions (i.e., moisture), and degradation of supporting equipment such as relays and communication devices. The condition assessment methodology for this asset class is presented in Table 4-9 below.

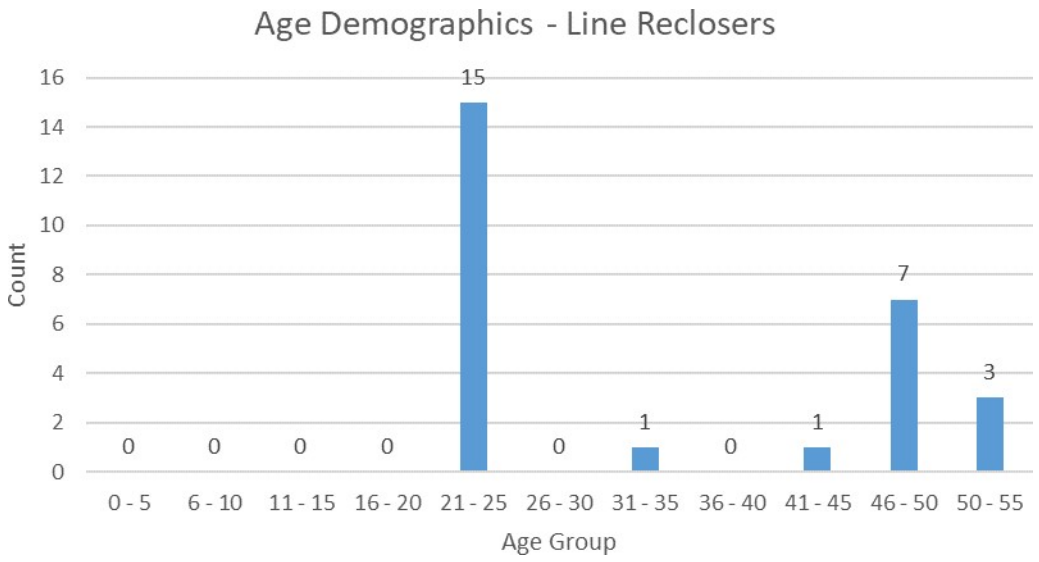
Table 4-9: Line Reclosers HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	6	A, B, C, D, E	4, 3, 2, 1, 0	24
Visual Inspection	3	A, B, C, D, E	4, 3, 2, 1, 0	12
IR Scanning	2	A, B, C, D, E	4, 3, 2, 1, 0	8

Total Score	44

InnPower deploys a total of 27 Line Reclosers in its distribution system. The age demographics for this asset class are presented below in Figure 4-18. A report published by the OEB and Kinectrics outlines that the TUL for this asset class is 40 years. The age demographics presented below show that 11 units are currently beyond the TUL threshold. Given that this represents 41% of the line reclosers population, there is a significant proportion of units that have aged beyond the TUL and may carry short-term failure risk.

Figure 4-18: Line Reclosers Age Distribution



The condition assessment results are presented in Figure 4-19 below. A significant proportion of units (12 units or 44% of the population) is assessed to be in Poor condition. These units should be further investigated and monitored as they may carry short-term failure risk. In addition, there is a material population of units in the Fair condition category (7 units or 26% of the population) that should be monitored. While these units are not likely to pose an immediate failure risk, they may degrade and require intervention over the next five to ten years.

Figure 4-19: Line Reclosers HI Results



4.1.10 Capacitors

Capacitors are devices that fundamentally consist of two oppositely charged conductors that are able to store energy and control the flow of electricity. They are commonly used in power grids to minimize reactive loss and improve the efficiency of the electrical distribution system. Common degradation mechanisms for capacitors include age-based degradation (i.e., wear and tear on capacitor sub-components over time) and degradation due to environmental factors (e.g., high temperatures or the presence of moisture). Some forms of degradation can result in catastrophic failure that poses safety and reliability risks. The condition assessment methodology for this asset class is presented below in Table 4-10.

Table 4-10: Capacitors HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	1	A, B, C, D, E	4, 3, 2, 1, 0	4
IR Scanning	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Total Score				8

Currently, InnPower's Capacitors asset class consists of nine units located at six stations. The age demographics for this asset class are provided in Figure 4-20 below. Six capacitors were installed in 2001 (i.e., present day age of 20 years) and three capacitors were installed in 2008 (i.e., present day age of 13 years). The estimated TUL for this asset class is 30 years. There are currently no units beyond this threshold in InnPower's Capacitors population. In addition, there are no units that will approach the 30-year TUL threshold in the next five years. Given these circumstances, it is reasonable to assume that the Capacitors asset class is in a generally healthy state and the likelihood of significant short-term risk is low. This conclusion is further supported by the results of the condition assessment presented in Figure 4-21 which indicate that all units are in Good or Very Good condition.

Figure 4-20: Capacitor Age Demographics

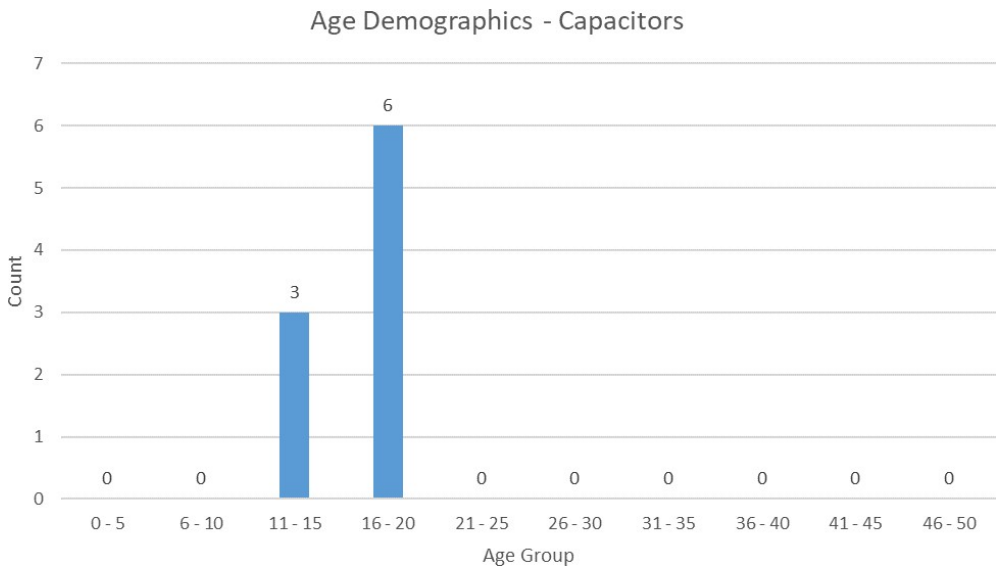
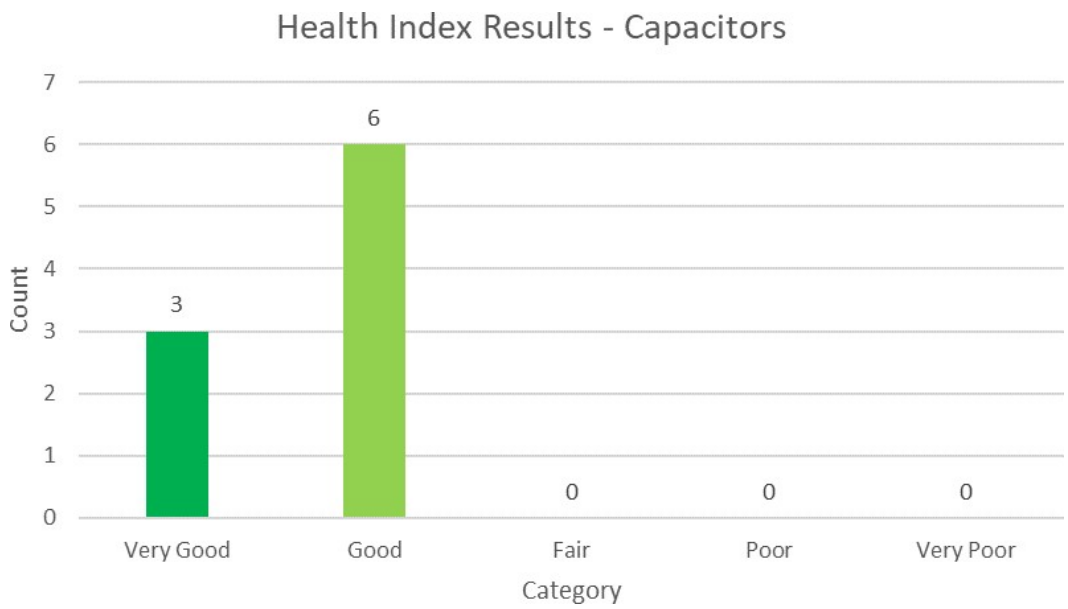


Figure 4-21: Capacitors HI Results



4.2 Station Assets

4.2.1 Station Power Transformers

Power transformers are key station assets that are used to step down the voltage from the transmission to sub-transmission systems, or from the sub-transmission system to distribution levels. Computing the HI for a power transformer requires a combination of various end-of-life criteria for its components. The condition assessment methodology for this asset class is presented in Table 4-11 below.

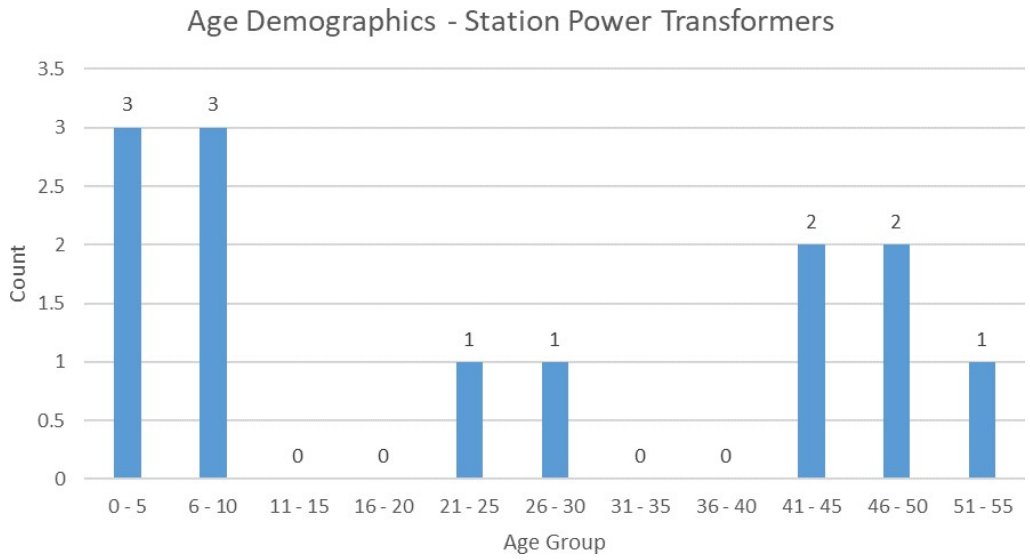
Table 4-11: Power Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	6	A, B, C, D, E	4, 3, 2, 1, 0	24
Visual Inspection	10	A, B, C, D, E	4, 3, 2, 1, 0	40
IR Scanning	6	A, B, C, D, E	4, 3, 2, 1, 0	24
DGA	10	A, B, C, D, E	4, 3, 2, 1, 0	40
Oil Quality	8	A, B, C, D, E	4, 3, 2, 1, 0	32
Insulation Power Factor	10	A, B, C, D, E	4, 3, 2, 1, 0	40

Winding Resistance	5	A, B, C, D, E	4, 3, 2, 1, 0	20
Turns Ratio	5	A, B, C, D, E	4, 3, 2, 1, 0	20
Total Score				240

InnPower currently has a total of 13 Station Power Transformers within its distribution system – the age demographics for this asset class are presented in Figure 4-22 below. The OEB Kinectrics report outlines that the TUL for Station Power Transformers is 45 years – in comparing the age demographics presented below to this threshold, it is evident that some risk exists. There are currently three units that are beyond the recommended TUL and an additional two units that will be beyond the TUL in the next five years. However, it is important to consider the implications of the age demographics in conjunction with the condition assessment results.

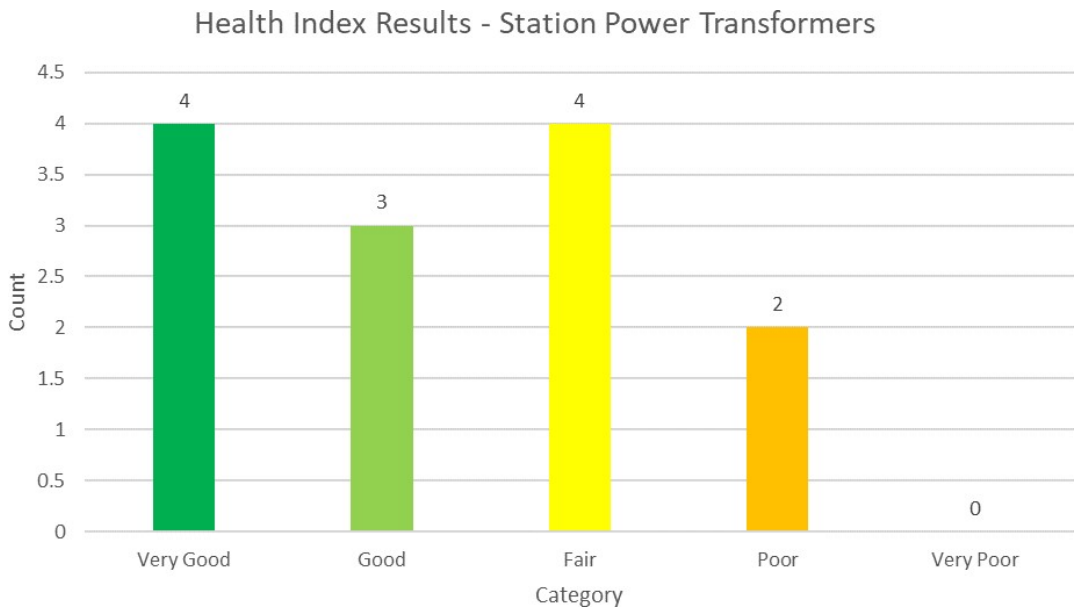
Figure 4-22: Power Transformer Age Demographics



The condition demographics for this asset class are presented in Figure 4-23 below. A health index score is available for each asset as all units met the 60% DAI threshold for station assets. The results of the condition assessment indicate that this asset class is in a generally healthy state as the majority of units fall into the Good or Very Good condition categories (7 units or 54% of the population). However, there are two units which are currently assessed to be in Poor condition – these units should be investigated as they may pose a short-term

failure risk. In addition, the utility should closely monitor the four units classified in the Fair condition category as they may degrade into Poor or Very Poor condition over the next five to ten years.

Figure 4-23: Power Transformer HI Results



4.2.2 Station Power Transformer Tap Changers

A power transformer tap changer is a device that supports the function of power transformers by allowing operators to change the output voltage by adjusting the turns ratio. The condition assessment methodology for this asset class is presented in Table 4-12 below.

Table 4-12: Power Transformer Tap Changer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Visual Inspection	3	A, B, C, D, E	4, 3, 2, 1, 0	12
DGA	3	A, B, C, D, E	4, 3, 2, 1, 0	12
Oil Quality	2	A, B, C, D, E	4, 3, 2, 1, 0	8
IR Scanning	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Total Score				44

InnPower has 13 Tap Changers in its distribution system and the age demographics for these units are presented in Figure 4-24 below. A report published by the OEB and Kinectrics estimates that the TUL for Power Transformer Tap Changers is 30 years. There are currently six Tap Changers that are beyond the recommended TUL and there is one unit that will exceed the TUL in the next five years. Although this implies some risk, it is important to consider the results of the condition assessment that are presented in Figure 4-25 below. The condition assessment results indicate that a notable portion of the population is in a healthy state as six units (or 46% of the population) are classified in the Good or Very Good Condition categories. There is currently one unit classified in the Poor condition category – InnPower should further investigate this unit as it may carry short-term failure risk. In addition, there are six units in the Fair condition category that should be monitored for additional degradation as they may require intervention in the next five to ten years.

Figure 4-24: Power Transformer Age Demographics

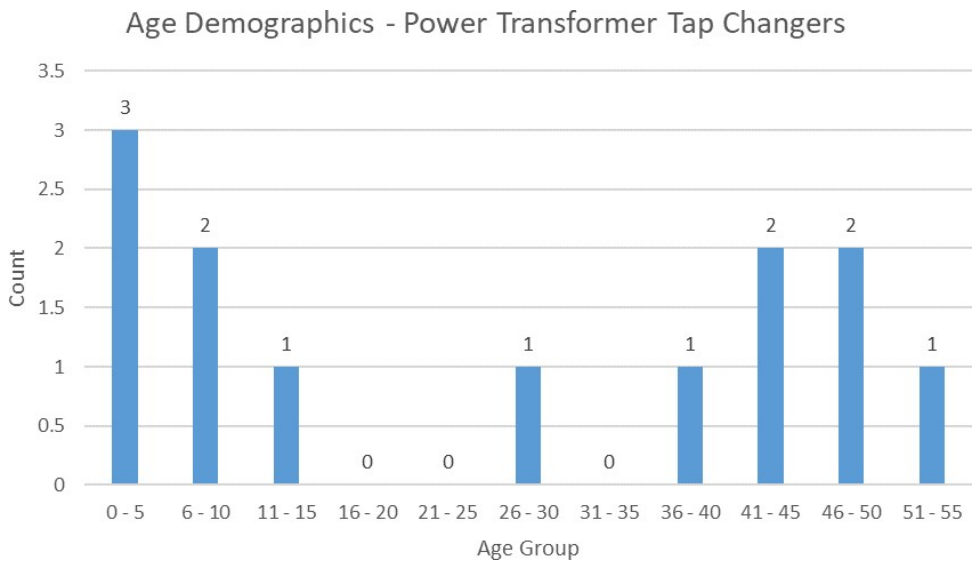
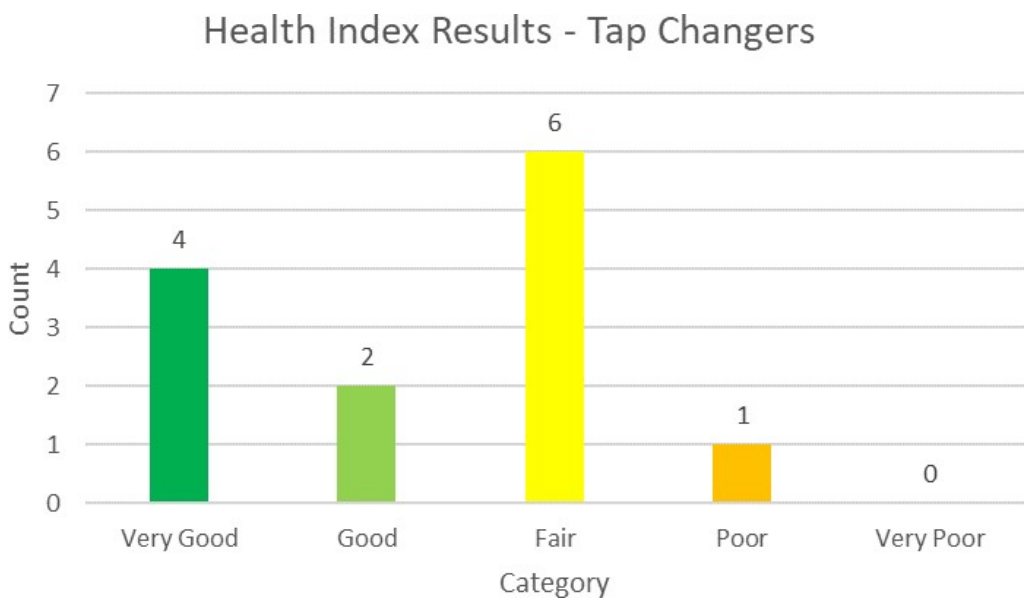


Figure 4-25: Power Transformer Tap Changer HI Results



4.2.3 Station Switches

A Station Switch is an electrical device that is used to connect or disconnect load from portions of the distribution system such as specific feeders. This asset class consists of the three sub-classes listed below.

- Station Switches – refers to Station Switches that are not within a switchgear (i.e., HV/LV load break switches and bus tie switches).
- Switchgear Switches – refers to Station Switches that are located within a switchgear.
- 44kV Transrupters – refers to 44kV Transrupters, which are protective devices designed for operation on the primary high-voltage side of a station transformer. InnPower deploys three 44kV Transrupters in its system.

The condition assessment methodologies for the three sub-classes are presented in Table 4-13 below.

Table 4-13: Station Switch HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Station Switches				
Visual Inspection	5	A, B, C, D, E	4, 3, 2, 1, 0	20
IR Scanning	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Contact Resistance	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Insulation Resistance	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Total Score				44
Switchgear Switches				
Visual Inspection	4	A, B, C, D, E	4, 3, 2, 1, 0	16
IR Scanning	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Total Score				20
44kV Transrupters				
Age	3	A, B, C, D, E	4, 3, 2, 1, 0	12
Visual Inspection	3	A, B, C, D, E	4, 3, 2, 1, 0	12
IR Scanning	1	A, B, C, D, E	4, 3, 2, 1, 0	4
Total Score				28

InnPower does not currently have records of age data for the Station Switches or Switchgear Switches sub-classes. The age demographics for 44kV Transrupters are presented in Figure 4-26 below. InnPower's Transrupter population is limited to three units located at Belle Ewart (installed 2017), Big Bay Point (installed 2020), and Bob Duego (installed 2006). This sub-class is estimated to be in good condition as all units are relatively young. The condition demographics for InnPower's 44kV Transrupters are presented in Figure 4-27 below and indicate that all units are in Very Good condition.

Figure 4-26: 44kV Transrupter Age Demographics

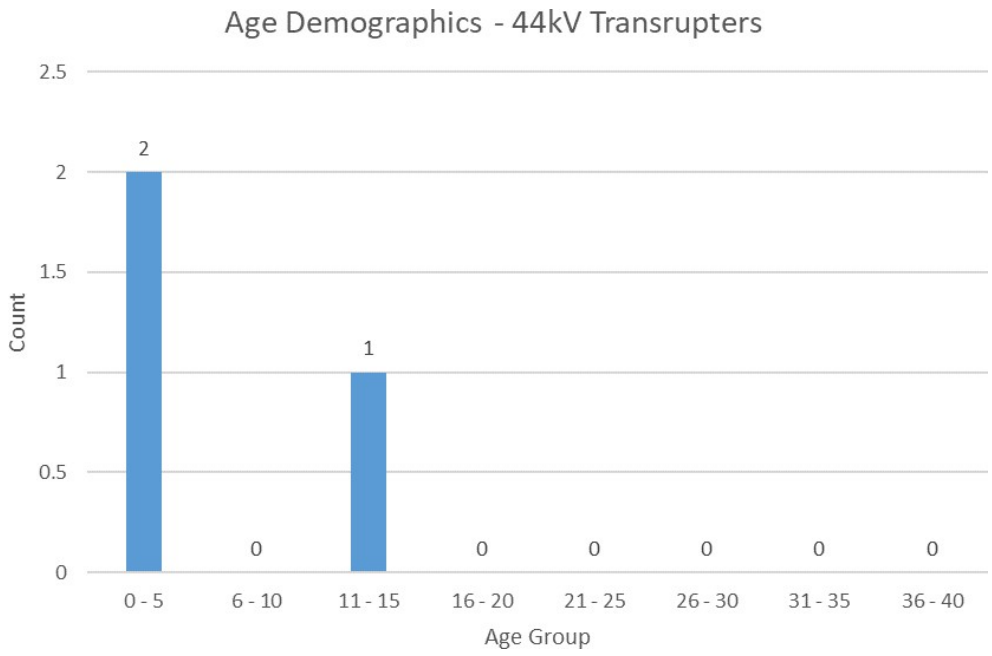
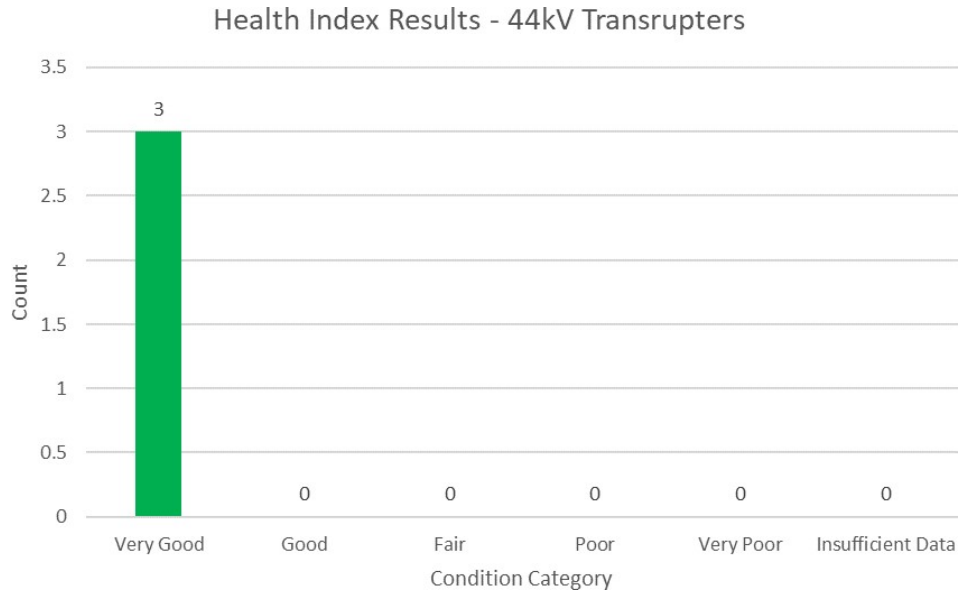
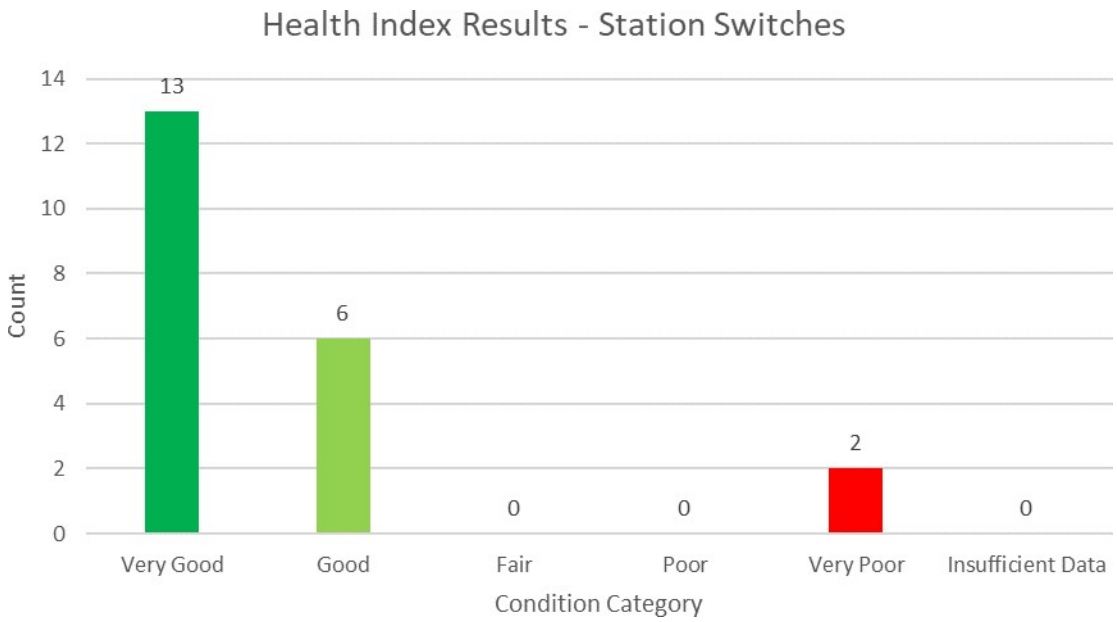


Figure 4-27: 44kV Transrupters Sub-Class HI Results



The Station Switches sub-class consists of 21 units and the condition demographics for these assets are presented in Figure 4-28 below. Although the vast majority of units are in Good or Very Good condition (19 units or 90% of the population), there are two units that are classified in the Very Poor condition category. These units should be investigated immediately as they likely pose a high short-term failure risk. It is advised that the utility take an appropriate asset intervention action to address these high-risk assets.

Figure 4-28: Station Switches Sub-Class HI Results



InnPower currently has 14 Switchgear Switches at its substation sites. The condition demographics for this asset class are presented in Figure 4-29 below. These units are generally in excellent condition as all assets within this sub-class are classified in the Very Good condition category. Figure 4-30 presents the combined condition demographics for all three sub-classes.

Figure 4-29: Switchgear Switches Sub-Class HI Results

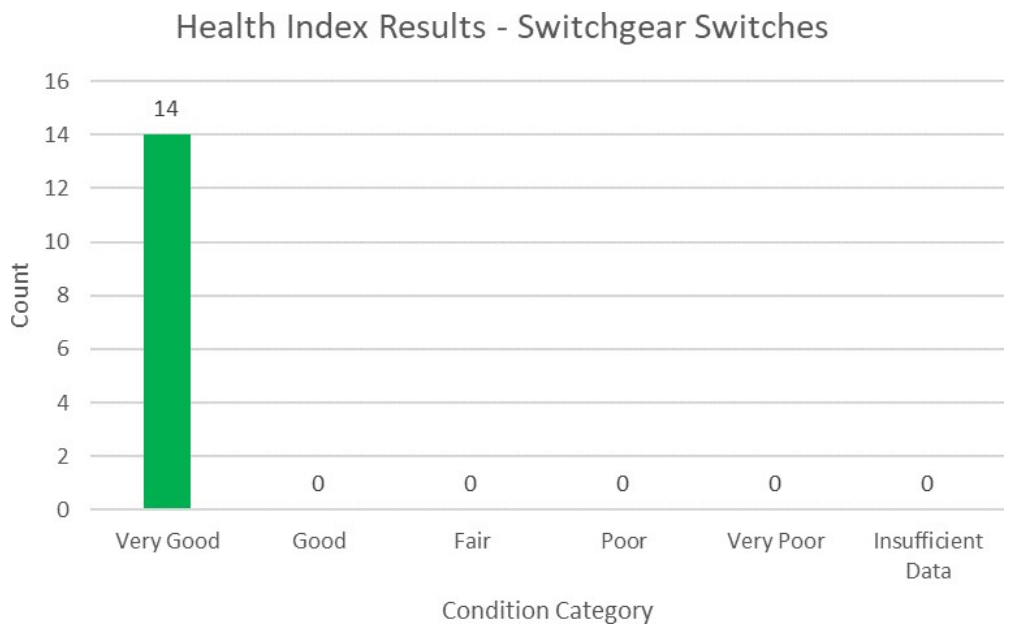
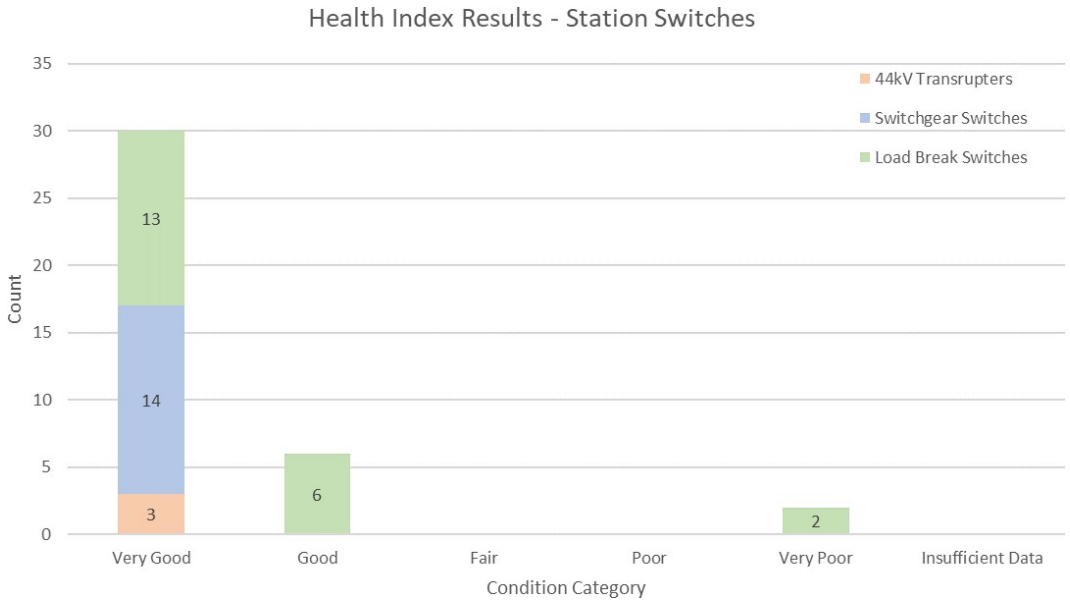


Figure 4-30: Station Switches HI Results



4.2.4 Station Reclosers

Station reclosers are used to detect and interrupt momentary faults – these assets have automatic service restoration capabilities that enable efficient operations. The condition assessment methodology is presented in Table 4-14 below. InnPower owns and operates 30 Station Reclosers at its substation sites and the age demographics for these units are available in Figure 4-31 below. The OEB Kinectrics report outlines that the expected TUL of Station Reclosers is 45 years, and no units are approaching the TUL, as all are less than 20 years old. This is reflected in the condition assessment results in Figure 4-32, as all the units are in the Good or Very Good Condition.

Table 4-14: Station Recloser HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	3	A, B, C, D, E	4, 3, 2, 1, 0	12
IR Scanning	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Visual Inspection	3	A, B, C, D, E	4, 3, 2, 1, 0	12
Number of Operations	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Total Score				40

Figure 4-31: Station Recloser Age Demographics

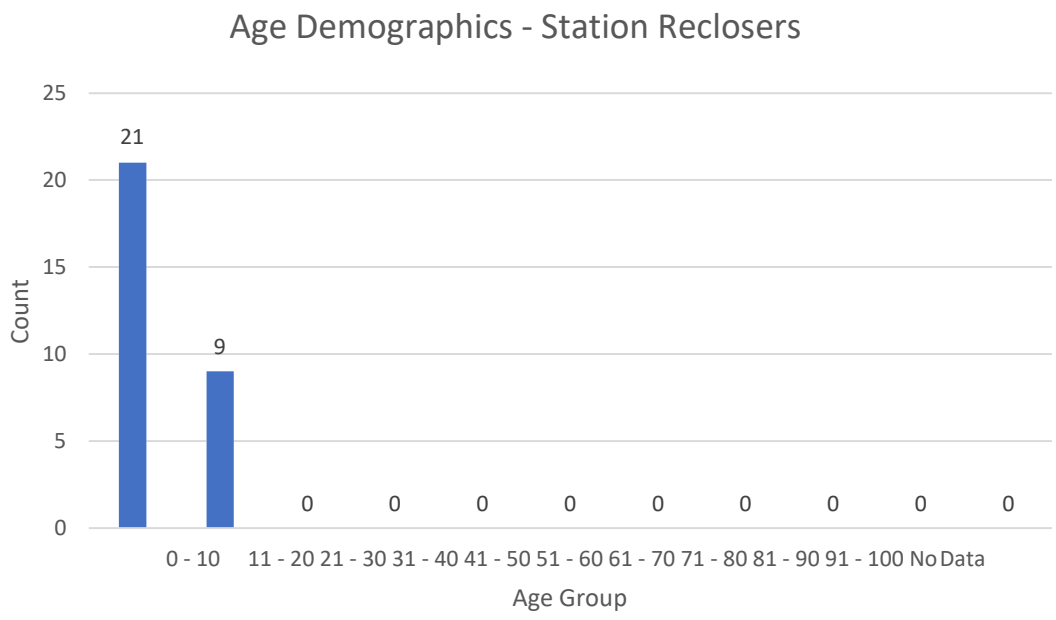
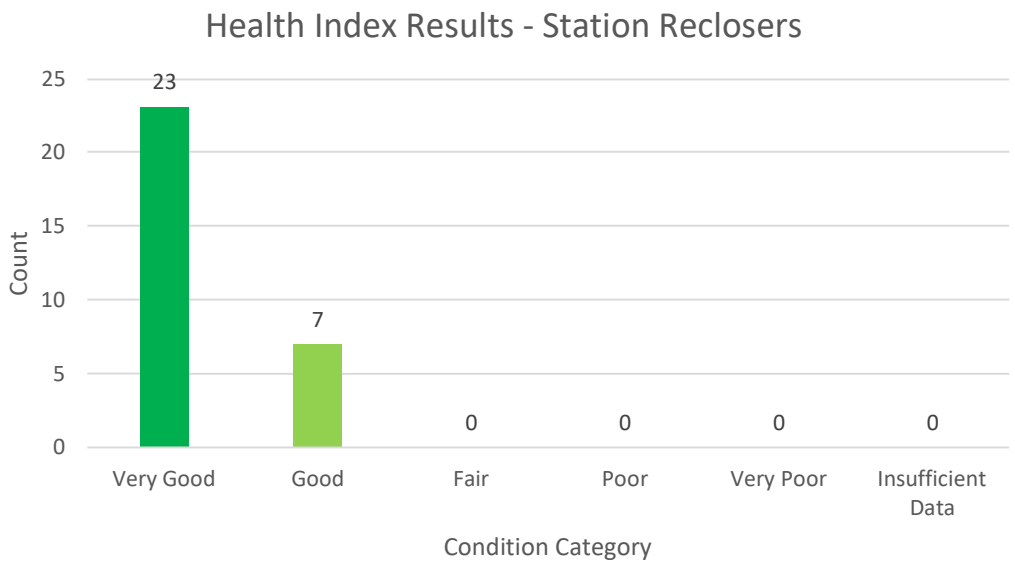


Figure 4-32: Station Recloser HI Results



4.2.5 Station Service Transformers

Station service transformers are a class of power transformer that tap directly into the incoming high voltage line and step-down power for use at the substation site. The condition assessment methodology for this asset class is presented in Table 4-15 below. InnPower currently deploys 12 Station Service Transformers at its station sites. The age demographics for this asset class are presented in Figure 4-33 below. The OEB Kinectrics report outlines that the expected TUL of Station Service Transformers is 45 years. There are currently two units that are beyond this TUL threshold and there is one unit that will exceed this threshold in the next five years. Although this implies that some risk exists, the condition assessment results (presented in Figure 4-34 below) indicate that this asset class is in excellent condition as all units are in the Good or Very Good condition categories.

Table 4-15: Station Service Transformer

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age	3	A, B, C, D, E	4, 3, 2, 1, 0	12
Visual Inspection	5	A, B, C, D, E	4, 3, 2, 1, 0	20
IR Scanning	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Total Score				40

Figure 4-33: Station Service Transformer Age Demographics

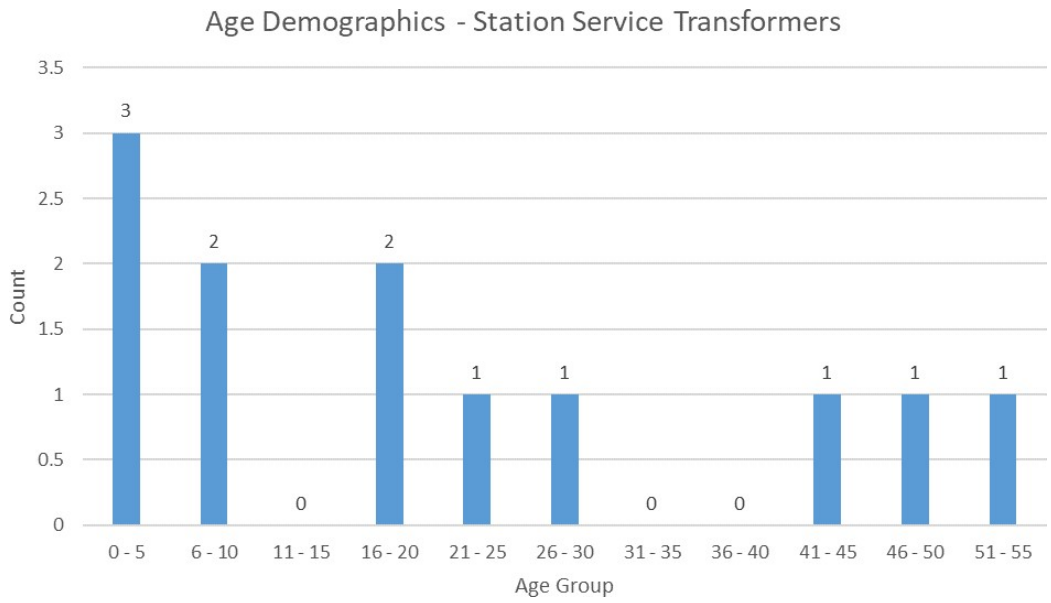
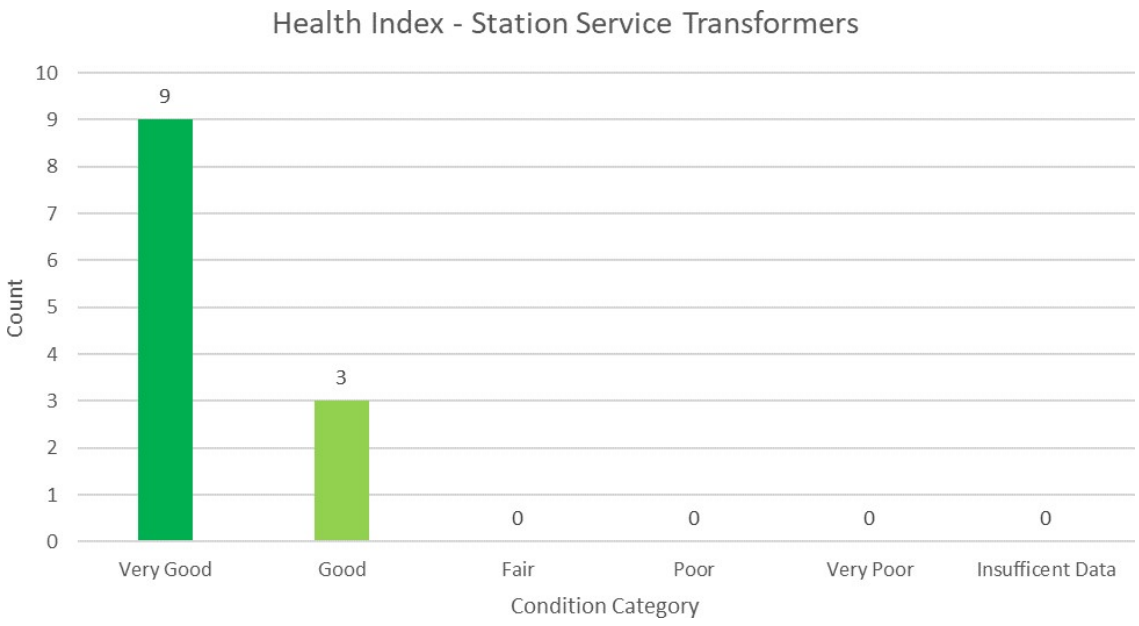


Figure 4-34: Station Service Transformer HI Results



4.2.6 Station Lighting Arresters

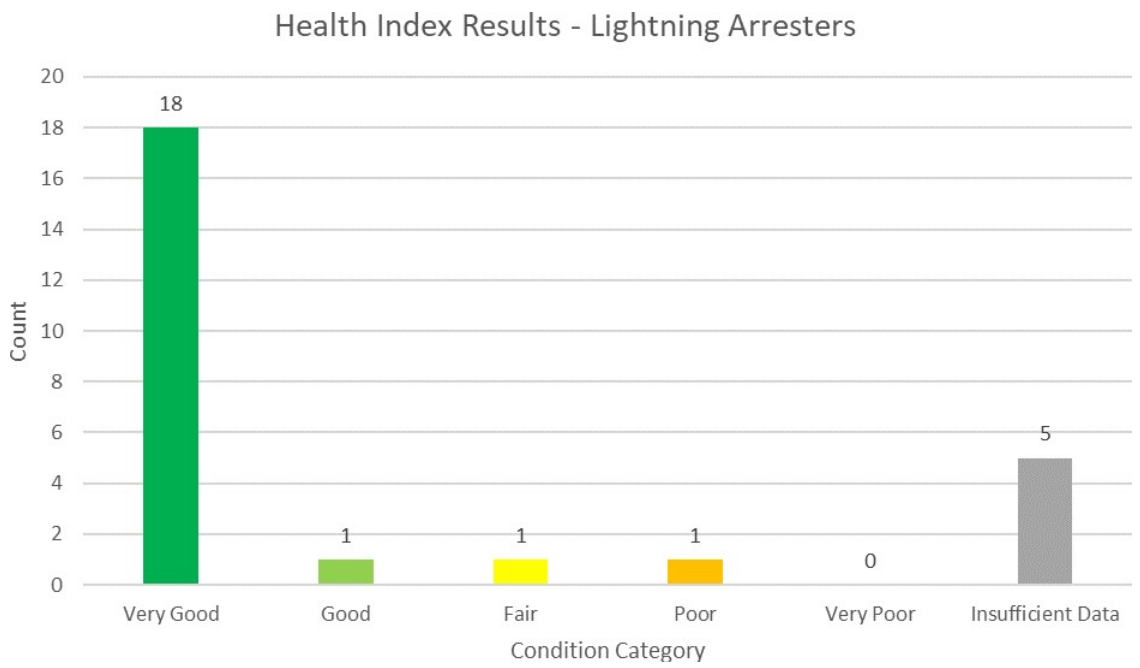
Lightning Arresters are protective devices that shield other assets from lightning strikes by diverting surges to a ground terminal. Over time, lightning arresters are expected to see a decline in condition due to degradation factors including but not limited to ageing, moisture ingress, and overvoltage scenarios. The condition assessment methodology for this asset class is presented in Table 4-16 below.

Table 4-16: Station Lighting Arresters HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	3	A, B, C, D, E	4, 3, 2, 1, 0	12
Insulation Resistance	3	A, B, C, D, E	4, 3, 2, 1, 0	12
IR Scanning	2	A, B, C, D, E	4, 3, 2, 1, 0	8
Total Score				32

InnPower currently has a total of 26 Lightning Arresters at its distribution stations, or two per station power transformer (i.e., one on the primary side and one on the secondary side). Age demographics are not available for this asset class as age data is not captured in any existing datasets. However, the health index results are presented in Figure 4-35 below. The health index demographics indicate that this asset class is in good condition as 73% of units are classified in the Good or Very Good condition categories. There is one unit assessed to be in Poor condition that should be further investigated as it is likely to pose a short-term failure risk – the utility should take the appropriate asset intervention action to mitigate this risk. In addition, there is one unit classified in the Fair condition category that should be monitored as it may degrade to Poor or Very Poor condition over the next five to ten years. The five assets in the Insufficient Data category did not have sufficient data for the completion of a condition assessment due to a lack of insulation resistance testing data.

Figure 4-35: Station Lighting Arresters HI Results



4.2.7 Station Power Fuses

Power fuses provide over-current protection during overload conditions or short circuits. Table 4-17 summarizes the HI formulation for the Station Power Fuses asset class. Given that there is no age data available for this asset class, age demographics cannot be presented.

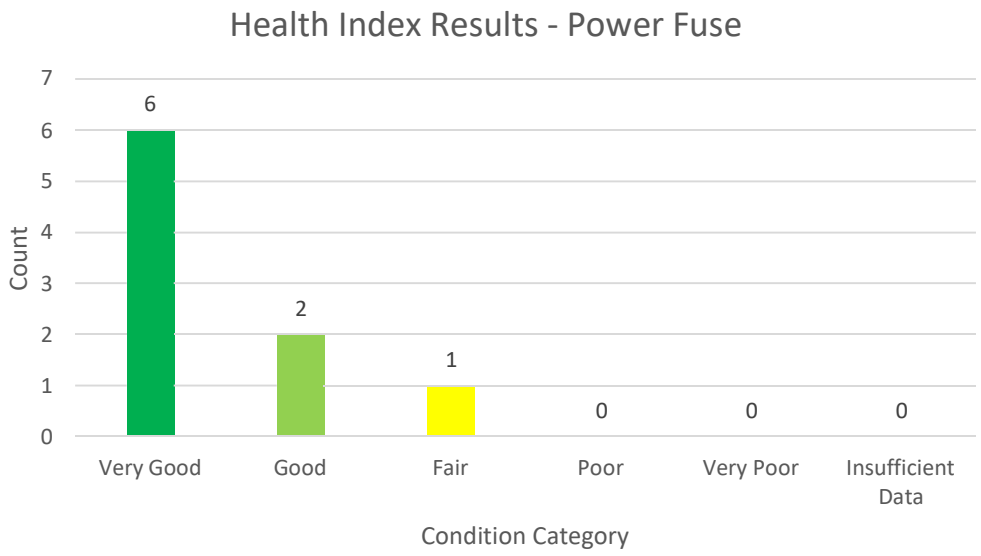
Table 4-17: Station Power Fuse HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	2	A,C,E	4,2,0	8
IR Scanning	1	A,B,C,D,E	4,3,2,1,0	4
Contact Resistance	3	A,B,D,E	4,3,1,0	12
Insulation Resistance	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				36

InnPower currently has a total of nine station power fuses located at its distribution stations. The condition assessment results for this asset class are presented in Figure 4-36 below.

The health index scores indicate that the power fuses asset is in good condition overall as 89% of the population is categorized in Good or Very Good condition. However, there is one unit that is assessed to be in Fair condition – the utility should monitor this units as it may degrade to Poor or Very Poor condition over the long term.

Figure 4-36: Station Power Fuse HI Results



4.2.8 Station GroundGrids

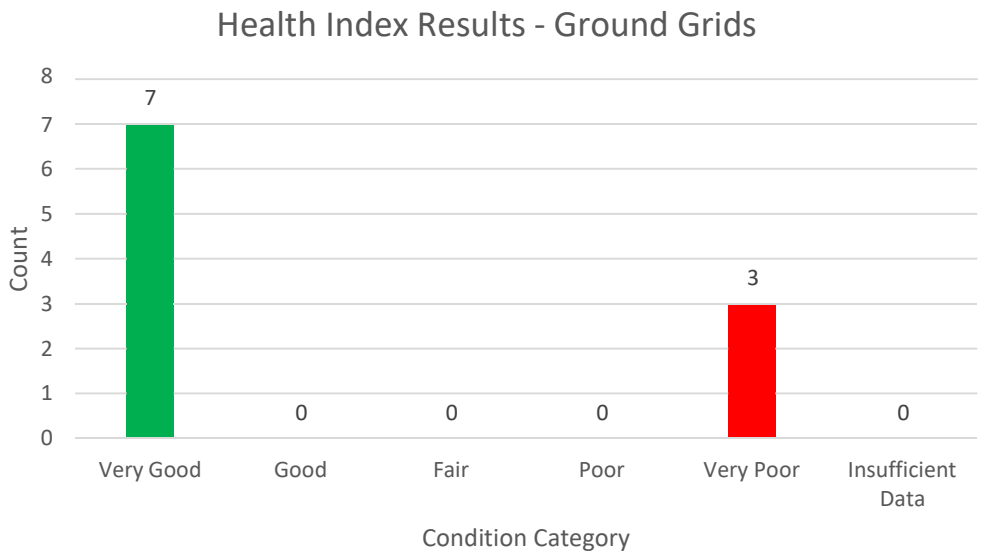
The purpose of a substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e., line-to-ground faults. The Health Index for station ground grids is calculated by considering visual inspection and ground resistance testing results from InnPower's station inspection forms. Table 4-18 summarizes the HI formulation for station facilities. Given the nature of this asset class, age data was not available – therefore, age demographics cannot be presented.

Table 4-18: Ground Grid HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	10	A,C,E	4,2,0	40
Total Score				40

InnPower has ten stations within its service territory. The condition assessment results are presented in Figure 4-37 below. The health index results indicate that the majority of the asset class (70% of the population) is in Very Good condition. However, there are three Ground Grids that are assessed to be in Very Poor condition (Leonard Beach DS, Brian Wilson DS and Stroud DS) – these assets should be further investigated and addressed through an appropriate asset intervention strategy such as replacement or refurbishment.

Figure 4-37: Ground Grid HI Results



4.2.9 Station Facilities

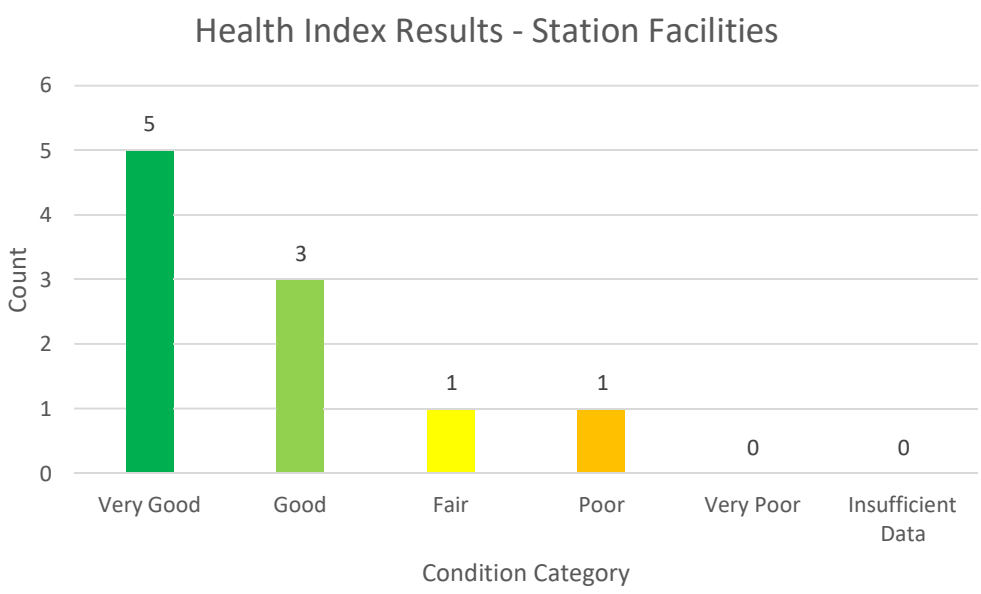
The Station Facilities asset class refers to several non-distribution assets located at InnPower's station sites such as the substation yard, fence, and structures. The integrity of station structure, fence, and yard contribute the safety of the station and the performance of the assets therein. The HI for station facilities is calculated by using the visual inspection results from InnPower's station inspection forms. Table 4-19 summarizes the HI formulation for station facilities. Given the nature of this asset class, age data was not available – therefore, age demographics cannot be presented.

Table 4-19: Station Facilities HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Yard Visual Inspection	2	A,B,C,D,E	4,3,2,1,0	8
Fence Visual Inspection	4	A,C,E	4,2,0	16
Structure Visual Inspection	5	A,C,E	4,2,0	20
Health & Safety	2	A,C,E	4,2,0	8
Electrical Panel	1	A,C,E	4,2,0	4
Lighting	1	A,C,E	4,2,0	4
HVAC	1	A,C,E	4,2,0	4
Total Score				64

InnPower owns ten stations within its service territory. The condition assessment results are presented in Figure 4-38 below. Most Station Facilities are in Very Good or Good condition (80% of the population). However, there is one station in the Poor condition category; Leonard Beach - the station should be further investigated and any significant deficiencies should be corrected. In addition, there is one station facility in Fair condition that should be monitored as it may degrade to Poor or Very Poor condition over the next five to ten years.

Figure 4-38: Station Facilities HI Results



5 Conclusions

The overall condition demographics for InnPower's distribution assets are presented in Figure 5-1 below. Both the distribution switches asset classes and the capacitors asset class are in excellent condition as all units are classified in the Good or Very Good condition categories. In addition, the majority of assets in all asset classes except for polemount transformers and line reclosers are also in Good or Very Good condition. Excluding the SCADA mate switches and capacitors, all asset classes have a subset of units that are classified in the Fair condition category. These units may experience further degradation over the next ten years and should be monitored to ensure that they do not degrade to Poor or Very Poor condition. Only the wood poles, polemount transformers, motorized 44kV switches, and line reclosers asset classes contain units that are classified in Poor or Very Poor condition. These assets carry short-term failure risk and should be investigated immediately – it is advised that the utility take the appropriate asset intervention strategy (i.e., replacement or refurbishment) to mitigate this risk.

Figure 5-2 below provides a summary of the condition assessment results for the station asset classes. The condition of InnPowers station assets is notably better than its distribution assets, as evidenced by the large proportion of units in the Very Good/Good condition categories. The station reclosers and station service transformers asset classes are in excellent condition as all units are classified in the Good/Very Good condition categories. There are several asset classes with a notable population of Fair condition assets that should be monitored for signs of additional degradation as they may degrade to Poor or Very Poor condition over the next ten years. However, the utility should consider the fact that certain station asset classes are critical to their operations – it is advised that InnPower take asset intervention actions to address Fair condition units that serve key functions in the short-term. It is recommended that the utility further investigate all Poor and Very Poor condition assets in the ground grids, facilities, switches, lightning arresters, tap changers, and power transformers asset classes. As outlined above, these assets can carry high short-term failure risk that should be mitigated through asset intervention such as replacement or refurbishment as soon as possible.

Figure 5-1: Distribution Assets Health Index Results

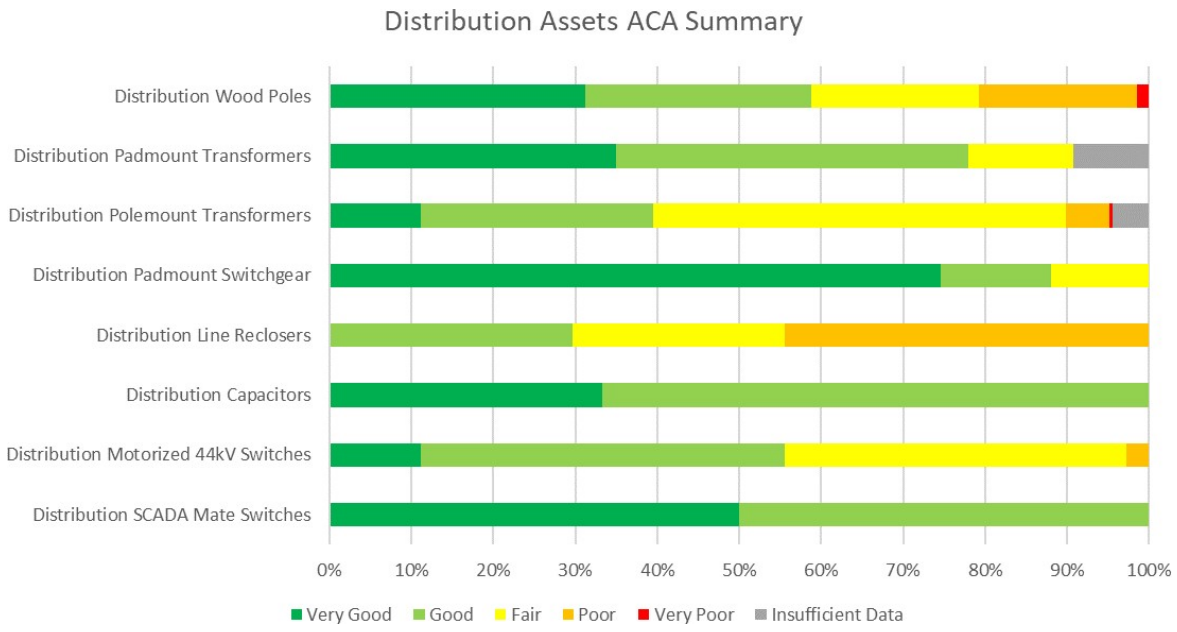
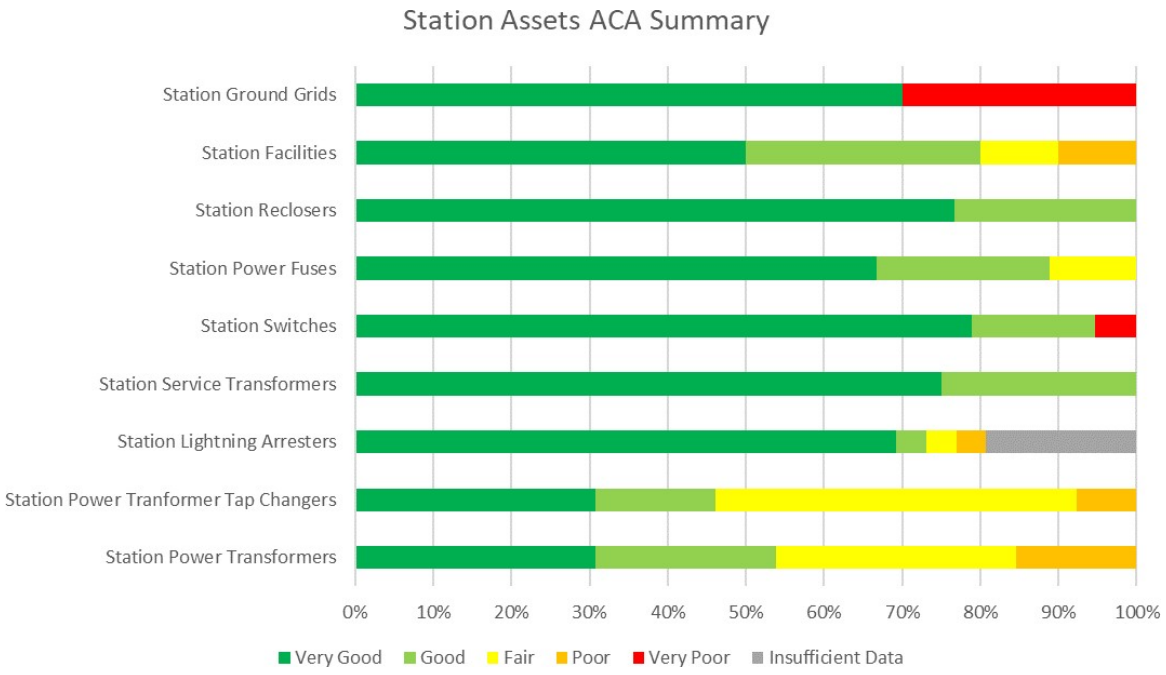


Figure 5-2: Station Assets Health Index Results



6 Recommendations

A complete ACA framework for InnPower represents an integral component of its broader AM framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows for InnPower's investment decision-making to be further enhanced with the current information regarding the state of the assets. There are also further opportunities to introduce new data collected, improve on data availability, and continuously improve the ACA framework.

This section breaks down METSCO's recommendations into the following categories:

1. Asset intervention strategies;
2. HI improvements; and
3. Data availability improvements.

6.1 Asset Intervention Strategies

Asset intervention options include replacement, refurbishment, or enhanced maintenance. Assets in Poor or Very Poor condition should be prioritized for intervention in the short-term. Fair-condition assets may also need to be addressed in the short-term, depending on risk. Long-term planning considerations should also consider the number of assets in Fair condition that will continue to degrade and the age profile of the assets.

Where feasible, asset intervention should be bundled; for example, into overhead rebuild projects, underground rebuild projects, and substation rebuild projects. Secondary bus should be replaced at the same time as the primary cables/conductors in the rebuild projects.

6.2 Health Index Improvements

For select asset classes, a recommended HI formulation was used for InnPower's ACA framework. The following set of recommendations target additional condition parameters that can be incorporated for specific asset classes to improve the HI formulation and provide InnPower with additional data to refine its asset condition calculations. The recommendations are based on improving the ACA framework over time and should not be interpreted as suggesting that immediate action is warranted. The following tables highlight the condition parameter name, a short description of the reasoning to include the condition

parameter, and a priority of importance to include it into the specific asset's class HI framework. The priority is dependent on the condition parameter's weighting in comparison to the current HI framework condition parameter's weights.

1. Distribution Polemount Transformers

Table 6-1: Data Collection Recommendation for Distribution Polemount Transformers

Criteria	Reasoning	Priority
Visual Inspection	Although the condition assessment consists of multiple condition parameters that represent an acceptable level of data quality, the inclusion of a visual inspection criteria would increase the completeness of the assessment. Given the size of the polemount transformers asset class, the utility should balance the need for additional condition assessment data with its available budget and resources for performing these additional inspections.	Low

2. Distribution Padmount Transformers

Table 6-2: Data Collection Recommendation for Distribution Padmount Trans formers

Criteria	Reasoning	Priority
Visual Inspection	Although the condition assessment consists of multiple condition parameters that represent an acceptable level of data quality, the inclusion of a visual inspection criteria would increase the completeness of the assessment. Given the size of the padmount transformers asset class, the utility should balance the need for additional condition assessment data with its available budget and resources for performing these additional inspections.	Low

3. Distribution SCADA Mate Switches

Table 6-3: Data Collection Recommendation for Distribution SCADA Mate Switches

Criteria	Reasoning	Priority
Visual Inspection	Although the condition assessment consists of multiple condition parameters that represent an acceptable level of data quality, the inclusion of a visual inspection criteria would increase the completeness of the assessment. In addition, the inclusion of distribution SCADA mate switches in the routine line inspections is a relatively low-effort improvement that would produce material benefit.	Low

4. Distribution Line Reclosers

Table 6-4: Data Collection Recommendation for Distribution Line Reclosers

Criteria	Reasoning	Priority
Asset Data	As part of the data submission for this asset class, InnPower provided timing test data. However, this information could not be used in the condition assessment as the line reclosers registry did not contain serial numbers for each unit. In addition, there were several data quality issues identified for this asset class. It is recommended that the utility establish a complete record of asset data include key information such as serial numbers, manufacture dates, sub types, and ratings.	Medium

5. Distribution Capacitors

Table 6-5: Data Collection Recommendation for Distribution Capacitors

Criteria	Reasoning	Priority
Visual Inspection	The asset class assessment is currently based on a combination of age and IR scanning. The addition of visual inspection data would enable a more complete condition assessment. Given the low quantity of capacitors in the distribution system, it is recommended that InnPower complete this exercise as it would be a relatively low-effort improvement with material benefit.	Low

6. Station Switches

Table 6-6: Data Collection Recommendation for Station Switches

Criteria	Reasoning	Priority
Age	Age data was not available at the time of completion of this ACA project for the Station Switches and Switchgear Switches sub classes. The inclusion of age data would enable a more complete condition assessment and additional insights through the production of asset age demographics. Additional priority is assigned to this recommendation as it is a low-effort improvement that provides material benefit.	Medium

7. Station Lightning Arresters

Table 6-7: Data Collection Recommendation for Station Lightning Arresters

Criteria	Reasoning	Priority
Age	Age data was not available at the time of completion of this ACA project. The inclusion of age data would enable a more complete condition assessment and additional insights through the production of asset age demographics. Additional priority is assigned to this recommendation as it is a low-effort improvement that provides material benefit.	High

8. Station Power Fuses

Table 6-8: Data Collection Recommendation for Station Power Fuses

Criteria	Reasoning	Priority
Age	Age data was not available at the time of completion of this ACA project. The inclusion of age data would enable a more complete condition assessment and additional insights through the production of asset age demographics. Additional priority is assigned to this recommendation as it is a low-effort improvement that provides material benefit.	High

6.3 Data Collection Improvements

Data availability is critical to produce prudent, accurate, and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA, the quality of the HI is dependent on the available data. For condition parameters with low data availability METSCO recommends that InnPower continue collecting the information related to these data points.

Additionally, for an asset to have a valid HI, it must meet a minimum 70% of available data across the condition parameters used in the HI formulation for distribution assets and 65% for station. As part of future improvement opportunities, it is recommended that InnPower continue capturing asset data for condition parameters that are currently available for a small proportion of the asset population, such that valid Health Indices can be produced across the population. It is expected that with every passing year, the inspection record database will continue to grow, allowing for Health Indices to be calculated for the remaining population.

Lastly, METSCO noticed that some condition parameters recorded by InnPower vary in the detail with respect to the grading scheme. Some parameters will have a three-tier grade (e.g., Good, Fair, and Poor) and others may have five levels (e.g., from Very Good to Very Poor). METSCO recommends for InnPower to evaluate options of changing some condition parameters recorded to a five-level grade, as doing so can provide more defined segregation between assets that need immediate attention and those that can still be in-service without intervention in the short term.

METSCO recommends that InnPower continue to work on mitigating the existing data gaps, such that more degradation parameters can be assigned actual grades, thus expanding the sample size of valid HI, and capturing all possible degradation of the evaluated assets. InnPower's testing, inspection, and maintenance programs are well-positioned to continue to capture this information using processes and technologies in place within the organization.

Appendix A – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

Figure A-0-1: METSCO Clients



METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over ten years. Our founders are the pioneers of the first Health

Index methodology for power equipment in North America as well as the most robust risk-based analytics on the market today for high-voltage assets. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led, and sat on stand defending their own DSPs as utility staff giving METSCO the qualified expertise to provide its service to InnPower.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

Appendix 2-5-5 OEB Appendix 2-D Overhead Expense

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Bridge Year	2024 Test Year
Distribution Operations	$ 1,600,622	$ 1,396,958	$ 1,313,975	$ 1,104,679	$ 1,548,761	$ 1,370,149	$ 1,741,822	$ 1,974,901
Distribution Maintenance	$ 616,264	$ 631,893	$ 652,489	$ 762,332	$ 1,049,233	$ 948,218	$ 880,390	$ 1,115,647
Billing and Collecting	$ 1,016,438	$ 1,085,093	$ 1,132,149	$ 1,251,092	$ 1,067,987	$ 1,475,945	$ 1,156,048	$ 1,194,581
Community Relations	$ 6,406	$ 72,722	$ 48,694	$ 76,635	$ 104,431	$ 98,992	$ 109,700	$ 113,874
Administrative and General	$ 2,761,323	$ 2,584,086	$ 2,480,413	$ 3,056,246	$ 2,675,570	$ 3,119,310	$ 3,622,841	$ 3,916,465
Total OM&A Before Capitalization (B)	$ 6,001,052	$ 5,770,751	$ 5,627,720	$ 6,250,984	$ 6,445,982	$ 7,012,614	$ 7,510,801	$ 8,315,468

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Bridge Year	2024 Test Year	Directly Attributable? (Yes/No)	Explanation for Any Change in Treatment of Capitalized Overhead
Employee benefits	$ 227,366	$ 445,012	$ 655,964	$ 859,327	$ 1,117,063	$ 1,222,077	$ 1,399,347	$ 1,488,388	Yes	Directly attributable to total labour costs charged to capital - InnPower began to use less contractors in 2019 for some capital work
Fleet/truck time	$ 264,058	$ 238,369	$ 268,096	$ 344,237	$ 403,335	$ 484,512	$ 496,625	$ 509,041	Yes	Directly attributable to total fleet costs charged to capital - InnPower began to use less contractors in 2019 for some capital work
Initial delivery and handling costs	$ 91,346	$ 175,448	$ 315,527	$ 278,907	$ 229,332	$ 228,407	$ 234,117	$ 239,970	Yes	Directly attributable costs charged to capital - InnPower began to use less contractors in 2019 for some capital work
Total Capitalized OM&A (A)	$ 582,771	$ 858,830	$ 1,239,587	$ 1,482,471	$ 1,749,730	$ 1,934,996	$ 2,130,089	$ 2,237,399		

% of Capitalized OM&A (=A/B)	10%	15%	22%	24%	27%	28%	28%	27%		

Appendix 2-5-6 OEB Appendix 2-G Service Reliability and Quality Indicators

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Excluding Loss of Supply and Major Event Days					Including Major Event Days, Excluding Loss of Supply					Including Loss of Supply, Excluding Major Event Days					Including Loss of Supply and Major Event Days				
	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
SAIDI	2.66	1.52	1.81	1.78	1.04	4.78	1.52	5.07	3.73	2.52	3.04	1.57	2.19	1.78	1.04	5.16	1.57	5.45	3.73	2.52
SAIFI	0.88	0.61	1.10	0.70	0.87	1.26	0.61	2.05	1.37	1.58	0.96	0.63	1.28	0.70	0.87	1.34	0.63	2.23	1.37	1.58

	5 Year Historical Average																			
SAIDI					1.762					3.524					1.923					3.685
SAIFI					0.832					1.374					0.889					1.431

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2018	2019	2020	2021	2022
Low Voltage Connections	90.0%	91.84%	99.56%	100.00%	99.50%	95.83%
High Voltage Connections	90.0%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	83.85%	90.40%	92.53%	90.18%	82.96%
Appointments Met	90.0%	87.21%	98.40%	99.51%	100.00%	100.00%
Written Response to Enquiries	80.0%	99.69%	99.90%	99.46%	99.86%	99.56%
Emergency Urban Response	80.0%	N/A	N/A	N/A	N/A	N/A
Emergency Rural Response	80.0%	95.74%	97.92%	100.00%	100.00%	98.04%
Telephone Call Abandon Rate	10.0%	3.98%	2.21%	2.51%	1.89%	1.55%
Appointment Scheduling	90.0%	95.25%	95.88%	99.96%	99.91%	100.00%
Rescheduling a Missed Appointment	100.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Reconnection Performance Standard	85.0%	98.90%	100.00%	100.00%	100.00%	100.00%

Appendix 2-5-7 ACM Model 2025-2027

InnPower Corporation has filed an ACM Model for 2025-2027 separately in Excel as Exhibit 2, Appendix 2-5-7: ACM Model 2025-2027.