Exhibit 2a – Rate Base
2027 Cost of Service

InnPower Corporation
EB-2026-0052

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2-1-1 RATE BASE OVERVIEW

1. INTRODUCTION

This Exhibit provides an overview of InnPower's 2027 Distribution Rate Base. In accordance with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate Applications Cost of Service dated December 16, 2025, 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 2024 approved to 2027 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 2027 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.

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-BA of IPC_2027COS_Chapter_2_Appendices_20260727.

InnPower's 2027 Rate Base used in developing the detailed rates is proposed at $132,711,606.

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 2024 to 2027 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 2024 to 2027 ($'000s)

	Approved	Historical Period / Actual		Bridge	Test
	2024	2024	2025	2026	2027
Opening Gross Assets	91,686	103,326	118,687	135,817	152,205
Closing Gross Assets	99,356	118,687	135,817	152,205	175,571
Average Gross Assets	**94,346**	**109,832**	**127,252**	**144,011**	**163,888**
Opening Accumulated Depreciation	(21,235)	(21,878)	(25,451)	(29,351)	(33,435)
Closing Accumulated Depreciation	(24,027)	(25,451)	(29,351)	(33,435)	(37,910)
Average Accumulated Depreciation	**(22,631)**	**(23,665)**	**(27,401)**	**(31,393)**	**(35,672)**
Opening Net Book Value	112,922	125,203	144,139	165,168	185,639
Closing Net Book Value	123,383	144,139	165,168	185,639	213,481
Average Net Book Value	**71,715**	**86,167**	**99,851**	**112,618**	**128,215**
Working Capital Allowance	3,209	4,018	4,159	4,367	4,496
TOTAL	74,924	90,185	104,011	116,985	132,712

Table 2-2: Rate Base 2024 Approved versus 2027 Test Year ($'000s)

	Approved 2024	Test Year 2027	Change 2024 to 2027
Opening Gross Assets	91,686	152,205	60,518
Closing Gross Assets	99,356	175,571	76,214
Average Gross Assets	**94,346**	**163,888**	**69,541**
Opening Accumulated Depreciation	(21,235)	(33,435)	(12,199)
Closing Accumulated Depreciation	(24,027)	(37,910)	(13,883)
Average Accumulated Depreciation	**(22,631)**	**(35,672)**	**(13,041)**
Opening Net Book Value	112,922	185,639	72,718
Closing Net Book Value	123,383	213,481	90,097
Average Net Book Value	**71,715**	**128,215**	**56,500**
Working Capital Allowance	3,209	4,496	1,287
TOTAL	74,924	132,712	57,787

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/or 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 2024 to 2027 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. 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 2024 to 2027 is shown in Table 2-3 below:

Table 2-3: Summary of Rate Base 2024 to 2027 ($'000s)

	Approved	Historical Period / Actual		Bridge	Test
	2024	2024	2025	2026	2027
Opening Gross Assets	91,686	103,326	118,687	135,817	152,205
Closing Gross Assets	99,356	118,687	135,817	152,205	175,571
Average Gross Assets	**94,346**	**109,832**	**127,252**	**144,011**	**163,888**
Opening Accumulated Depreciation	(21,235)	(21,878)	(25,451)	(29,351)	(33,435)
Closing Accumulated Depreciation	(24,027)	(25,451)	(29,351)	(33,435)	(37,910)
Average Accumulated Depreciation	**(22,631)**	**(23,665)**	**(27,401)**	**(31,393)**	**(35,672)**
Opening Net Book Value	112,922	125,203	144,139	165,168	185,639
Closing Net Book Value	123,383	144,139	165,168	185,639	213,481
Average Net Book Value	**71,715**	**86,167**	**99,851**	**112,618**	**128,215**
Working Capital Allowance	3,209	4,018	4,159	4,367	4,496
TOTAL	74,924	90,185	104,011	116,985	132,712

2. RATE BASE VARIANCE ANALYSIS

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

2024 Approved to 2027 Test Year (+$57.8M)

Table 2-4: 2027 Test Year versus 2024 OEB Approved ($'000s)

	Approved 2024	Test Year 2027	Change 2024 to 2027
Opening Gross Assets	91,686	152,205	60,518
Closing Gross Assets	99,356	175,571	76,214
Average Gross Assets	**94,346**	**163,888**	**69,541**
Opening Accumulated Depreciation	(21,235)	(33,435)	(12,199)
Closing Accumulated Depreciation	(24,027)	(37,910)	(13,883)
Average Accumulated Depreciation	**(22,631)**	**(35,672)**	**(13,041)**
Opening Net Book Value	112,922	185,639	72,718
Closing Net Book Value	123,383	213,481	90,097
Average Net Book Value	**71,715**	**128,215**	**56,500**
Working Capital Allowance	3,209	4,496	1,287
TOTAL	74,924	132,712	57,787

- InnPower's Average Net Fixed Assets for 2027 are $56.5M higher than the 2024 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 2027 is $1.3M higher than the 2024 approved level due to higher levels of OM&A and Cost of Power.

2024 Actual to 2024 Approved (+$15.3M)

Table 2-5 below shows the variance between the 2024 OEB approved Rate Base and 2024 Actual Rate Base.

Table 2-5: 2024 Actual versus 2024 OEB Approved ($'000s)

	Historical Period / Actual			
	2024 Actual vs 2024 Approved			
	Approved 2024	Actual 2024	Var $	Var %
Average Gross Assets	94,346	109,832	15,485	16%
Average Accumulated Depreciation	(22,631)	(23,665)	(1,033)	5%
Average Net Book Value	71,715	86,167	14,452	20%
Working Capital Allowance	3,209	4,018	809	25%
TOTAL	74,924	90,185	15,260	20%

- InnPower's Actual Average Net Fixed Assets for 2024 are $14.5M higher than the 2024 approved level, notably due to compliant revisions made to capital contribution calculation.
- InnPower's Working Capital Allowance for 2024 is $0.8M higher than the 2024 approved level due to higher actual OM&A versus Approved levels.

2025 Actual to 2024 Actual (+$13.8M)

Table 2-6 below shows the variance between the 2024 and 2025 Actual Rate Base.

Table 2-6: 2025 Actuals versus 2024 Actuals ($'000s)

	Historical Period / Actual			
	2025 vs 2024			
	Actual 2024	Actual 2025	Var $	Var %
Average Gross Assets	109,832	127,252	17,421	16%
Average Accumulated Depreciation	(23,665)	(27,401)	(3,736)	16%
Average Net Book Value	86,167	99,851	13,684	16%
Working Capital Allowance	4,018	4,159	141	4%
TOTAL	90,185	104,011	13,826	15%

- InnPower's Average Net Fixed Assets for 2025 are $13.7M higher than the 2024 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 2025 is $0.14M higher than 2024.

2026 Bridge to 2025 Actual (+$13.0M)

Table 2-7 below shows the variance between the 2025 Actual Rate Base and 2026 Bridge Year Rate Base.

Table 2-7: 2026 Bridge versus 2025 Actuals ($'000s)

	Forecast Period / Planned			
	2026 vs 2025			
	Actual 2025	Bridge 2026	Var $	Var %
Average Gross Assets	127,252	144,011	16,759	13%
Average Accumulated Depreciation	(27,401)	(31,393)	(3,992)	15%
Average Net Book Value	99,851	112,618	12,767	13%
Working Capital Allowance	4,159	4,367	207	5%
TOTAL	104,011	116,985	12,974	12%

- InnPower's Average Net Fixed Assets for 2026 are forecast to be $13.0M higher than the 2025 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 2026 is forecast to be $0.21M higher than the 2025 level due to increase in OM&A costs.

2027 Test to 2026 Bridge (+$15.7M)

Table 2-8 below shows the variance between the 2026 Bridge Year and 2027 Test Year Rate Base.

Table 2-8: 2027 Test versus 2026 Bridge ($'000s)

	Forecast Period / Planned			
	2027 vs 2026			
	Bridge 2026	Test 2027	Var $	Var %
Average Gross Assets	144,011	163,888	19,877	14%
Average Accumulated Depreciation	(31,393)	(35,672)	(4,280)	14%
Average Net Book Value	112,618	128,215	15,597	14%
Working Capital Allowance	4,367	4,496	130	3%
TOTAL	116,985	132,712	15,727	13%

- InnPower's Average Net Fixed Assets for 2027 are forecast to be $15.7M higher than the 2026 level due to in-service additions of $23.4 million, offset by depreciation, as outlined in InnPower's Distribution System Plan.
- InnPower's Working Capital Allowance for 2027 is forecast to be $0.13M higher than the 2026 level due to increases in Cost of Power and OM&A from 2026 to 2027.

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: 2024 OEB Approved, 2024-2025 Actuals, 2026 Bridge Year and 2027 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-BA of IPC_2027COS_Chapter_2_Appendices_20260727.

Table 2-9: Summary of 2024 to 2027 Continuity Schedules

Summary of Continuity Schedules					
	2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test
Gross Fixed Assets					
Opening Balance	91,686,175	103,325,537	118,687,491	135,817,082	152,204,505
Non-Regulated Building	(2,350,000)	(2,350,000)	0	0	0
Additions	10,085,730	17,227,718	17,493,197	16,387,423	23,366,074
Disposals	(65,451)	484,237	(363,606)	0	0
Closing Balance - excluding WIP	99,356,454	118,687,491	135,817,082	152,204,505	175,570,578
Average Gross Fixed Assets	**94,346,314**	**109,831,514**	**127,252,287**	**144,010,794**	**163,887,542**
Accumulated Depreciation					
Opening Balance	21,235,344	21,877,731	25,451,410	29,350,642	33,434,584
Non-Regulated Building	0	(48,822)	(48,822)	(48,822)	(48,822)
Additions	2,791,560	3,622,500	3,948,054	4,132,764	4,524,215
Disposals	24,026,904	25,451,410	29,350,642	33,434,584	37,909,977
Closing Balance - excluding WIP	21,235,344	21,877,731	25,451,410	29,350,642	33,434,584
Average Accumulated Depreciation	**22,631,124**	**23,664,570**	**27,401,026**	**31,392,613**	**35,672,281**
	71,715,190	**86,166,944**	**99,851,261**	**112,618,181**	**128,215,261**

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 2-10: Reconciliation of Depreciation Additions to Depreciation Expense

Depreciation Expense Reconciliation					
	2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test
Depreciation Additions	2,791,560	3,801,365	4,273,609	4,132,764	4,524,215
Less: Non-Regulated Building		(48,822)	(48,822)	(48,822)	(48,822)
Less: Fully Allocated Depreciation		(376,071)	(396,768)	(375,261)	(398,098)
Less: Deferred Revenue		1,774,045	2,194,271	2,375,673	2,732,262
Depreciation Expense	**2,791,560**	**5,150,518**	**6,022,290**	**6,084,354**	**6,809,558**

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 2027 OEB Approved Year, 2024-2025 Historical Years, 2026 Bridge Year, and 2027 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 2027 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 $175,570,578 at the end of the 2027 Test Year, representing an increase of $76,214,124 between the 2024 OEB Approved Year and the 2027 Test Year. Significant annual variances broken down by function are discussed below.

Table 2-11: Gross Asset Balances 2024 to 2027

		2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test	2024 OEB Approved to 2027 Test
Distribution Plant							
1609	Capital Contributions Paid	8,348,908	8,124,030	13,587,856	17,587,856	21,587,856	13,238,948
1612	Land Rights	397,396	401,896	401,896	401,896	401,896	4,500
1805	Land	1,049,593	1,049,593	1,049,593	1,049,593	1,049,593	0
1815	Transformer Station Equipment	1,003,404	0	0	0	0	(1,003,404)
1820	Distribution Station Equipment	24,439,656	20,716,550	22,195,551	23,103,378	26,190,112	1,750,456
1830	Poles, Towers & Fixtures	77,127,696	36,680,839	46,249,357	58,423,428	68,216,833	(8,910,863)
1835	OH Conductors & Devices	23,047,473	26,509,615	30,858,438	43,778,731	53,249,152	30,201,679
1840	UG Conduit	10,449,819	20,516,957	26,182,085	30,113,063	42,235,364	31,785,545
1845	UG Conductors & Devices	11,285,453	19,660,034	22,198,651	22,548,651	22,978,901	11,693,448
1850	Line Transformers	11,844,837	22,119,520	27,117,135	27,262,135	27,411,485	15,566,648
1855	Services (OH & UG)	10,395,612	12,301,309	14,227,509	14,227,509	14,227,509	3,831,897
1860	Meters	4,830,721	4,709,227	5,028,536	5,343,036	5,878,536	1,047,815
		184,220,569	**172,789,569**	**209,096,608**	**243,839,276**	**283,427,238**	**99,206,669**
General Plant							
1905	Land	1,015,496	1,015,496	1,015,496	1,015,496	1,015,496	0
1908	Buildings & Fixtures	10,745,835	10,770,358	10,809,504	10,886,379	11,181,379	435,545
1915	Office Furniture & Equipment	307,180	301,017	360,166	370,166	370,166	62,986
1930	Transportation Equipment	2,690,646	2,858,213	2,877,411	3,122,411	3,692,411	1,001,765
1935	Stores Equipment	135,334	135,334	135,334	135,334	135,334	0
1940	Tools, Shop & Garage Equipment	708,627	811,794	914,857	1,001,731	1,001,731	293,104
1945	Measurement & Testing Equipment	73,455	81,682	81,682	289,682	361,682	288,227
1980	System Supervisor Equipment	3,743,547	3,828,973	3,767,094	3,767,094	3,767,094	23,547
2005	Property Under Finance Lease	551,017	75,328	0	0	0	(551,017)
		19,971,137	**19,878,195**	**19,961,545**	**20,588,294**	**21,525,294**	**1,554,157**
Information Systems							
1611	Computer Software	2,272,141	1,991,126	2,219,481	2,843,898	4,581,926	2,309,785
1920	Computer Hardware	1,439,490	1,418,860	1,684,601	1,850,201	2,268,201	828,711
		3,711,631	**3,409,985**	**3,904,082**	**4,694,099**	**6,850,127**	**3,138,496**
Total Gross Balance before Contributed Capital		**207,903,336**	**196,077,750**	**232,962,235**	**269,121,670**	**311,802,659**	**103,899,323**
2440	Contributions & Grants	(108,546,882)	(77,390,259)	(97,145,153)	(116,917,165)	(136,232,081)	(27,685,199)
		99,356,454	**118,687,491**	**135,817,082**	**152,204,505**	**175,570,578**	**76,214,124**

2024 OEB Approved vs. 2024 Actuals

In 2024, InnPower's actual gross asset balances were higher than the 2024 OEB Approved amount by $19,331,037 or 19%.

See Table 2-12 below for the breakdown of gross asset balances by function and major plant account.

Table 2-12: 2024 OEB Approved vs. 2024 Actuals Gross Asset by USofA

		2024 OEB Approved	2024 Actual	Variance $	Variance %
Distribution Plant					
1609	Capital Contributions Paid	8,348,908	8,124,030	(224,878)	(3%)
1612	Land Rights	397,396	401,896	4,500	1%
1805	Land	1,049,593	1,049,593	0	0%
1815	Transformer Station Equipment	1,003,404	0	(1,003,404)	(100%)
1820	Distribution Station Equipment	24,439,656	20,716,550	(3,723,106)	(15%)
1830	Poles, Towers & Fixtures	77,127,696	36,680,839	(40,446,857)	(52%)
1835	OH Conductors & Devices	23,047,473	26,509,615	3,462,142	15%
1840	UG Conduit	10,449,819	20,516,957	10,067,138	96%
1845	UG Conductors & Devices	11,285,453	19,660,034	8,374,580	74%
1850	Line Transformers	11,844,837	22,119,520	10,274,682	87%
1855	Services (OH & UG)	10,395,612	12,301,309	1,905,697	18%
1860	Meters	4,830,721	4,709,227	(121,494)	(3%)
		184,220,569	**172,789,569**	**(11,430,999)**	**(6%)**
General Plant					
1905	Land	1,015,496	1,015,496	0	0%
1908	Buildings & Fixtures	10,745,835	10,770,358	24,523	0%
1915	Office Furniture & Equipment	307,180	301,017	(6,163)	(2%)
1930	Transportation Equipment	2,690,646	2,858,213	167,567	6%
1935	Stores Equipment	135,334	135,334	0	0%
1940	Tools, Shop & Garage Equipment	708,627	811,794	103,167	15%
1945	Measurement & Testing Equipment	73,455	81,682	8,227	11%
1980	System Supervisor Equipment	3,743,547	3,828,973	85,426	2%
2005	Property Under Finance Lease	551,017	75,328	(475,689)	(86%)
		19,971,137	**19,878,195**	**(92,942)**	**(0%)**
Information Systems					
1611	Computer Software	2,272,141	1,991,126	(281,015)	(12%)
1920	Computer Hardware	1,439,490	1,418,860	(20,630)	(1%)
		3,711,631	**3,409,985**	**(301,646)**	**(8%)**
Total Gross Balance before Contributed Capital		**207,903,336**	**196,077,750**	**(11,825,587)**	**(6%)**
2440	Contributions & Grants	(108,546,882)	(77,390,259)	31,156,623	(29%)
		99,356,454	**118,687,491**	**19,331,037**	**19%**

Distribution Plant:

In 2024, actual Distribution Plant assets were $11,430,999 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 2024, actual General Plant assets were $92,942 lower than the OEB Approved amount and actual Information System assets were $301,646 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.

2024 Actuals vs. 2025 Actuals

InnPower's actual gross asset balances increased by $17,129,591 or 14%, between the 2024 and 2025 Actuals. See Table 2-13 below for the breakdown of gross asset balances by function and major plant account.

Table 2-13: 2024 Actuals vs. 2025 Actuals Gross Asset by USofA

		2024 Actual	2025 Actual	Variance $	Variance %
Distribution Plant					
1609	Capital Contributions Paid	8,124,030	13,587,856	5,463,826	67%
1612	Land Rights	401,896	401,896	0	0%
1805	Land	1,049,593	1,049,593	0	0%
1820	Distribution Station Equipment	20,716,550	22,195,551	1,479,001	7%
1830	Poles, Towers & Fixtures	36,680,839	46,249,357	9,568,518	26%
1835	OH Conductors & Devices	26,509,615	30,858,438	4,348,823	16%
1840	UG Conduit	20,516,957	26,182,085	5,665,128	28%
1845	UG Conductors & Devices	19,660,034	22,198,651	2,538,618	13%
1850	Line Transformers	22,119,520	27,117,135	4,997,616	23%
1855	Services (OH & UG)	12,301,309	14,227,509	1,926,200	16%
1860	Meters	4,709,227	5,028,536	319,309	7%
		172,789,569	**209,096,608**	**36,307,039**	**21%**
General Plant					
1905	Land	1,015,496	1,015,496	0	0%
1908	Buildings & Fixtures	10,770,358	10,809,504	39,147	0%
1915	Office Furniture & Equipment	301,017	360,166	59,149	20%
1930	Transportation Equipment	2,858,213	2,877,411	19,198	1%
1935	Stores Equipment	135,334	135,334	0	0%
1940	Tools, Shop & Garage Equipment	811,794	914,857	103,064	13%
1945	Measurement & Testing Equipment	81,682	81,682	0	0%
1980	System Supervisor Equipment	3,828,973	3,767,094	(61,879)	(2%)
2005	Property Under Finance Lease	75,328	0	(75,328)	(100%)
		19,878,195	**19,961,545**	**83,350**	**0%**
Information Systems					
1611	Computer Software	1,991,126	2,219,481	228,355	11%
1920	Computer Hardware	1,418,860	1,684,601	265,742	19%
		3,409,985	**3,904,082**	**494,097**	**14%**
Total Gross Balance before Contributed Capital		**196,077,750**	**232,962,235**	**36,884,485**	**19%**
2440	Contributions & Grants	(77,390,259)	(97,145,153)	(19,754,894)	26%
		118,687,491	**135,817,082**	**17,129,591**	**14%**

Distribution Plant:

In 2025, actual Distribution Plant assets were $36,307,039 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 2025, actual General Plant assets were $83,350 higher than the previous year and actual Information System assets were $494,097 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.

2025 Actuals vs. 2026 Bridge Year

InnPower's gross asset balances are forecast to increase by $16,387,423 or 12%, between the 2025 actuals and the budgeted amounts for the 2026 Bridge Year. See Table 2-14 below for the breakdown of gross asset balances by function and major plant account.

Table 2-14: 2025 Actuals vs. 2026 Bridge Year Gross Asset by USofA

		2025 Actual	2026 Bridge	Variance $	Variance %
Distribution Plant					
1609	Capital Contributions Paid	13,587,856	17,587,856	4,000,000	29%
1612	Land Rights	401,896	401,896	0	0%
1805	Land	1,049,593	1,049,593	0	0%
1820	Distribution Station Equipment	22,195,551	23,103,378	907,827	4%
1830	Poles, Towers & Fixtures	46,249,357	58,423,428	12,174,071	26%
1835	OH Conductors & Devices	30,858,438	43,778,731	12,920,293	42%
1840	UG Conduit	26,182,085	30,113,063	3,930,977	15%
1845	UG Conductors & Devices	22,198,651	22,548,651	350,000	2%
1850	Line Transformers	27,117,135	27,262,135	145,000	1%
1855	Services (OH & UG)	14,227,509	14,227,509	0	0%
1860	Meters	5,028,536	5,343,036	314,500	6%
		209,096,608	**243,839,276**	**34,742,668**	**17%**
General Plant					
1905	Land	1,015,496	1,015,496	0	0%
1908	Buildings & Fixtures	10,809,504	10,886,379	76,875	1%
1915	Office Furniture & Equipment	360,166	370,166	10,000	3%
1930	Transportation Equipment	2,877,411	3,122,411	245,000	9%
1935	Stores Equipment	135,334	135,334	0	0%
1940	Tools, Shop & Garage Equipment	914,857	1,001,731	86,874	9%
1945	Measurement & Testing Equipment	81,682	289,682	208,000	255%
1980	System Supervisor Equipment	3,767,094	3,767,094	0	0%
		19,961,545	**20,588,294**	**626,749**	**3%**
Information Systems					
1611	Computer Software	2,219,481	2,843,898	624,417	28%
1920	Computer Hardware	1,684,601	1,850,201	165,600	10%
		3,904,082	**4,694,099**	**790,017**	**20%**
Total Gross Balance before Contributed Capital		**232,962,235**	**269,121,670**	**36,159,434**	**16%**
2440	Contributions & Grants	(97,145,153)	(116,917,165)	(19,772,012)	20%
		135,817,082	**152,204,505**	**16,387,423**	**12%**

Distribution Plant:

In 2026, budgeted Distribution Plant assets were $34,742,668 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 2026, budgeted General Plant assets were $626,749 higher than the previous year and budgeted Information System assets were $790,017 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.

2026 Bridge Year vs. 2027 Test Year

InnPower's gross asset balances are forecast to increase by $23,366,074 or 15% between the 2026 Bridge Year and the 2027 Test Year. See Table 2-15 below for the breakdown of gross asset balances by function and major plant account.

Table 2-15: 2026 Bridge Year vs. 2027 Test Year Gross Asset by USofA

		2026 Bridge	2027 Test	Variance $	Variance %
Distribution Plant					
1609	Capital Contributions Paid	17,587,856	21,587,856	4,000,000	23%
1612	Land Rights	401,896	401,896	0	0%
1805	Land	1,049,593	1,049,593	0	0%
1820	Distribution Station Equipment	23,103,378	26,190,112	3,086,734	13%
1830	Poles, Towers & Fixtures	58,423,428	68,216,833	9,793,405	17%
1835	OH Conductors & Devices	43,778,731	53,249,152	9,470,421	22%
1840	UG Conduit	30,113,063	42,235,364	12,122,301	40%
1845	UG Conductors & Devices	22,548,651	22,978,901	430,250	2%
1850	Line Transformers	27,262,135	27,411,485	149,350	1%
1855	Services (OH & UG)	14,227,509	14,227,509	0	0%
1860	Meters	5,343,036	5,878,536	535,500	10%
		243,839,276	**283,427,238**	**39,587,961**	**16%**
General Plant					
1905	Land	1,015,496	1,015,496	0	0%
1908	Buildings & Fixtures	10,886,379	11,181,379	295,000	3%
1915	Office Furniture & Equipment	370,166	370,166	0	0%
1930	Transportation Equipment	3,122,411	3,692,411	570,000	18%
1935	Stores Equipment	135,334	135,334	0	0%
1940	Tools, Shop & Garage Equipment	1,001,731	1,001,731	0	0%
1945	Measurement & Testing Equipment	289,682	361,682	72,000	25%
1980	System Supervisor Equipment	3,767,094	3,767,094	0	0%
		20,588,294	**21,525,294**	**937,000**	**5%**
Information Systems					
1611	Computer Software	2,843,898	4,581,926	1,738,028	61%
1920	Computer Hardware	1,850,201	2,268,201	418,000	23%
		4,694,099	**6,850,127**	**2,156,028**	**46%**
Total Gross Balance before Contributed Capital		**269,121,670**	**311,802,659**	**42,680,989**	**16%**
2440	Contributions & Grants	(116,917,165)	(136,232,081)	(19,314,916)	17%
		152,204,505	**175,570,578**	**23,366,074**	**15%**

Distribution Plant:

In 2027, budgeted Distribution Plant assets are $39,587,961 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 2027, budgeted General Plant assets are $937,000 higher than the previous year and budgeted Information System assets were $2,156,028 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 $13,768,399 between the 2024 OEB Approved Year and the 2027 Test Year. See Table 2-16 below for the annual accumulated depreciation balances, broken down by major plant account. Fluctuations by category are as follows:

- $15,978,653 increase to accumulated depreciation on Distribution Plant assets
- $3,150,773 increase to accumulated depreciation on General Plant assets
- $1,061,281 increase to accumulated depreciation on Information Systems assets
- $6,307,634 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 2-16: Accumulated Depreciation Balances 2024 to 2027

		2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test	2024 OEB Approved to 2027 Test
Distribution Plant							
1609	Capital Contributions Paid	336,134	328,742	763,574	1,212,748	1,757,477	1,421,343
1612	Land Rights	142,493	142,574	155,422	168,270	181,118	38,624
1815	Transformer Station Equipment	12,543	0	0	0	0	(12,543)
1820	Distribution Station Equipment	3,649,004	3,712,525	4,409,007	5,088,980	5,788,772	2,139,768
1830	Poles, Towers & Fixtures	5,519,385	4,432,530	5,371,738	6,325,171	7,442,382	1,922,997
1835	OH Conductors & Devices	3,287,989	3,391,010	3,934,339	4,672,588	5,579,420	2,291,431
1840	UG Conduit	1,472,873	1,773,494	2,379,606	3,080,540	3,851,782	2,378,909
1845	UG Conductors & Devices	2,963,817	3,263,878	3,834,784	4,374,802	4,919,704	1,955,887
1850	Line Transformers	2,377,379	2,680,500	3,284,489	3,862,407	4,442,275	2,064,896
1855	Services (OH & UG)	1,500,345	1,635,631	1,967,556	2,276,969	2,586,381	1,086,036
1860	Meters	2,461,407	2,460,756	2,671,800	2,907,475	3,152,710	691,303
		23,723,369	**23,821,640**	**28,772,315**	**33,969,949**	**39,702,022**	**15,978,653**
General Plant							
1908	Buildings & Fixtures	2,219,403	2,277,670	2,572,942	2,819,640	3,066,770	847,367
1915	Office Furniture & Equipment	261,216	236,644	255,902	267,935	280,524	19,308
1930	Transportation Equipment	1,089,688	1,632,668	2,026,641	2,401,902	2,800,000	1,710,312
1935	Stores Equipment	130,619	129,527	135,334	135,334	135,334	4,715
1940	Tools, Shop & Garage Equipment	424,790	434,484	492,867	551,265	614,489	189,699
1945	Measurement & Testing Equipment	61,400	59,773	64,971	71,461	88,451	27,051
1980	System Supervisor Equipment	2,050,802	2,054,337	2,203,867	2,429,692	2,655,517	604,715
2005	Property Under Finance Lease	252,395	66,959	0	0	0	(252,395)
		6,490,313	**6,892,061**	**7,752,525**	**8,677,230**	**9,641,086**	**3,150,773**
Information Systems							
1611	Computer Software	1,821,070	1,811,730	1,973,150	2,138,862	2,457,626	636,557
1920	Computer Hardware	1,021,354	964,135	1,081,552	1,253,116	1,446,078	424,724
		2,842,423	**2,775,866**	**3,054,701**	**3,391,978**	**3,903,704**	**1,061,281**
Total Gross Balance before Contributed Capital		**33,056,105**	**33,489,566**	**39,579,542**	**46,039,157**	**53,246,813**	**20,190,708**
2440	Contributions & Grants	(9,029,201)	(8,038,157)	(10,228,900)	(12,604,573)	(15,336,835)	(6,307,634)
		24,026,904	**25,451,410**	**29,350,642**	**33,434,584**	**37,909,977**	**13,883,074**

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 and 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. InnPower has completed versions of Appendix 2-BA (Fixed Asset Continuity Schedule), 2-BB (Service Life Comparison) and 2-C (Depreciation and Amortization Schedule) within IPC_2027COS_Chapter_2_Appendices_20260727.

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 2-17

below presents the derivation of the allowance for working capital for the historical 2024-2025, as well as the 2026 Bridge and 2027 Test Year.

Table 2-17: Working Capital Allowance (WCA) 2024 to 2027 ($'000s)

Investment Category	2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test
Power Supply Expenses	35,082	44,265	46,256	47,425	47,988
OM&A Expenses	7,707	9,306	9,202	10,796	11,963
Total Expenses for WC	42,789	53,571	55,458	58,221	59,951
Working Capital %	7.5%	7.5%	7.5%	7.5%	7.5%
TOTAL	**3,209**	**4,018**	**4,159**	**4,367**	**4,496**

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 2027 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 2-18 below and detailed in accordance with the Filing Requirements.

Table 2-18: Summary of 2027 Test Year Cost of Power Expense ($'000s)

2027 Test Year - Cop	
	Sub-Total

4705 -Power Purchased	$ 43,462,720
4707- Global Adjustment	$ 4,327,998
4708-Charges-WMS	$ 2,011,979
4714-Charges-NW	$ 4,421,001
4716-Charges-CN	$ 3,612,587
4750-Charges-LV	$ 1,417,054
4751-IESO SME	$ 131,534
Misc A/R or A/P	$ (11,396,723)
TOTAL	**$ 47,988,150**

4. COST OF POWER CALCULATIONS

Commodity

For the 2027 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"), non-RPP Class B and Class A customers was determined using:

- Day Ahead Market Ontario Zonal Price (DAM OZP) and Load Forecast Deviation Adjustment (LFDA) of $57.51 per kWh for RPP customers.
- Global Adjustment of $59.81 per kWh.

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 2027 Test Year COP calculation are as follows:

Wholesale Market

- Wholesale Market Service (WMS) charge of $0.0041 as established in the OEB EB-2025-0299 Decision and Order.

Transmission Network and Transmission Connection

- The most recent UTR (Network and Connection) are taken from the 2027 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 2027 RTSR Workform.

RSVA Adjustment

- Rural and Remote Electricity Rate Protection (RRRP) charge of $0.0006 as established in the OEB EB-2025-0299 Decision and Order.
- Class B Capacity Based Response charge of $0.0006 as established in the OEB EB-2025-0299 Decision and Order.

InnPower confirms the COP has been adjusted for the Ontario Electricity Rebate (23.5%).

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 2027 Test Year COP amount.

The split between RPP and Non-RPP volumes for 2027 was determined using the 2025 actual consumption by customer type (RPP and Non-RPP) and rate class.

In accordance with the Filing Requirements, the COP for the 2027 Test Year was derived from 2-ZA and 2-ZB of the Chapter 2 Appendices, filed as IPC_2027COS_Chapter_2_Appendices_20260727.

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 2024 to 2027 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 2024 to 2027 follows below.

2. CAPITAL EXPENDITURE SUMMARY

Capital expenditures from 2024 to 2027, broken down by major category, are provided in Table 2-19 below.

Table 2-19: Capital Expenditures 2024 to 2027 ($'000s)

Investment Category	2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test	2027 Test vs 2024 Actual	2027 Test vs 2024 Approved
System Access	30,350	19,869	27,172	22,447	25,543	5,674	(4,808)
System Renewal	1,429	8,379	5,484	1,682	2,749	(5,629)	1,320
System Service	16,313	5,440	5,281	7,142	8,901	3,461	(7,412)
General Plant	1,182	969	850	1,654	3,368	2,399	2,186
Capital Contributions	(31,415)	(17,062)	(19,831)	(19,772)	(19,315)	(2,253)	12,100
TOTAL	17,860	17,594	18,955	13,154	21,246	3,652	3,386

InnPower's 2027 Test Year Net Capital Expenditures are $21.2M as shown in Table 2-16 above. The 2027 Test Year expenditures are $3.7M greater than InnPower's 2024 Actual levels and $9.5M greater than the OEB approved 2024 levels. The 2027 expenditures are a 26% reduction from the Bridge Year.

The capital projects being proposed for the Test Year can be found in Appendix 1 Distribution System Plan

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 2024 to 2027 are shown below.

2-20: In-Service Additions from 2024 to 2027 (Net) ('$000s)

Investment Category	2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test	2027 Test vs 2024 Actual	2027 Test vs 2024 Approved
System Access	2,035	8,764	8,058	6,465	9,211	447	7,176
System Renewal	1,429	1,904	2,521	1,806	2,749	846	1,320
System Service	5,439	5,434	6,102	6,815	8,906	3,473	3,467
General Plant	1,182	1,126	812	1,302	3,282	2,156	2,100
TOTAL	10,086	17,228	17,493	16,387	24,149	6,921	14,063

InnPower's in-service additions in 2027 are $24.2M. The 2027 Test Year levels are $14.06M higher than the 2024 approved level and $6.9M higher than the 2024 actual levels. The 2027 Test Year in-service additions are approximately 47% higher than those in the Bridge Year.

A detailed discussion of InnPower's Capital Program over this period is provided in Appendix 1 Distribution System Plan.

2-5-2 CAPITAL EXPENDITURE VARIANCE ANALYSIS

1. CAPITAL EXPENDITURE VARIANCE ANALYSIS

Capital expenditures from 2024 to 2027, broken down by major category, are provided in Table 2-21 below.

Table 2-21: Capital Expenditures 2024 to 2027 ($'000s)

Investment Category	2024 OEB Approved	2024 Actual	2025 Actual	2026 Bridge	2027 Test	2027 Test vs 2024 Actual	2027 Test vs 2024 Approved
System Access	23,410	19,869	27,172	22,447	25,543	5,674	2,132
System Renewal	1,429	8,379	5,484	1,682	2,749	(5,629)	1,320
System Service	7,519	5,440	5,281	7,142	8,901	3,461	1,382
General Plant	1,022	969	850	1,654	3,368	2,399	2,346
Capital Contributions	(24,260)	(17,062)	(19,831)	(19,772)	(19,315)	(2,253)	4,945
TOTAL	9,120	17,594	18,955	13,154	21,246	3,652	12,126

InnPower has filed its Distribution System Plan as Appendix 1 to this Exhibit. InnPower has also filed OEB Appendices 2-AA and 2AB within IPC_2027COS_Chapter_2_Appendices_20260727.

2. YEAR OVER YEAR DETAILED VARIANCE ANALYSIS

Per the OEB's Filing Requirements[2] InnPower has included its variance analysis in its Distribution System Plan Section 5.4.1.1 Plan vs Actual Variances for the Historical Period.

3. CAPITAL CONTRIBUTIONS

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

Tables 2-27 below shows InnPower's capital contributions over the 2024 to 2027 period. The pattern of capital contributions is directly related to the type and volume of the projects undertaken.

[2] Filing Requirements for Electricity Distribution Cost of Service Rate Applications - 2026 Edition for 2027 Rate Applications, Chapter 2, Cost of Service, December 16,2025; Section 2.2.1 Rate Base

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

Table 2-27: Capital Contributions for the Historical and Forecasted Period 2024 to 2027 ($'000s)

Investment Category	Historical Period / Actual				Forecast Period / Planned					
	2025 vs 2024				Bridge 2026	Variance from 2025 $	Test 2027	Variance from 2025 $	Var $	Var %
	Actual 2024	Actual 2025	Var $	Var %					2027-2024	2027-2024
Capital Contributions	(17,062)	(19,831)	(2,769)	16%	(19,772)	59	(19,042)	789	(1,980)	12%

2-5-3 DISTRIBUTION SYSTEM PLAN

The Distribution System Plan and the corresponding appendices can be found in Appendix 1 to this Exhibit.

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.

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 of the employees who monitor inventory and issue materials and supplies.

Material Overhead costs 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. Changes in the overhead rates since the last rebasing are immaterial in amount.

InnPower has completed Appendix 2-D Overhead Expense of the Chapter 2 appendices showing a breakdown of OM&A before capitalization and capitalized OM&A.

Please see Table 2-28 and 2-29 for Appendix 2-D below.

Table 2-28: Appendix 2-D Summary of OM&A Before Capitalization

OM&A Before Capitalization	2024 Historical Year	2025 Historical Year	2026 Bridge Year	2027 Test Year
Distribution Operations	2,130,643	1,980,714	2,291,363	2,477,777

OM&A Before Capitalization	2024 Historical Year	2025 Historical Year	2026 Bridge Year	2027 Test Year
Distribution Maintenance	1,089,174	1,478,466	1,474,767	1,532,350
Billing and Collecting	1,755,764	1,452,978	1,759,966	2,045,156
Community Relations	56,859	70,369	133,284	130,668
Administrative and General[3]	4,273,840	4,219,037	5,136,266	5,777,163
Total OM&A Before Capitalization (B)	9,306,280	9,201,564	10,795,645	11,963,115

Table 2-29: Appendix 2-D Summary of Capitalized OM&A

Capitalized OM&A	2024 Historical Year	2025 Historical Year	2026 Bridge Year	2027 Test Year
Employee benefits	1,100,980	1,552,796	1,714,844	1,899,798
Costs of site preparation	550,727	509,467	562,635	623,318
Initial delivery and handling costs	580,714	456,332	503,955	558,308
Total Capitalized OM&A (A)	2,232,421	2,518,595	2,781,434	3,081,424

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

[3] Including property taxes

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 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 Appendix 1 of Exhibit 1.

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 2-30 and 2-31 below.

Table 2-30: Historical Reliability Performance Metrics - All Cause Codes

Metric	2021	2022	2023	2024	2025	Average
SAIDI	3.73	2.52	1.83	2.11		
SAIFI	1.37	1.58	1.17	2.48		

Table 2-31: Historical Reliability Performance Metrics - LOS and MED Adjusted

Metric	2021	2022	2023	2024	2025	Average
Loss of Supply Adjusted						
SAIDI	3.73	2.52	1.29	2.04		
SAIFI	1.37	1.58	0.87	2.35		
Loss of Supply and Major Event Days Adjusted						
SAIDI	1.78	1.04	1.29	1.60		
SAIFI	0.70	0.87	0.87	1.64		

Details relating to InnPower's reliability metrics can be found in the Distribution System Plan Section 5.2.3.2.2 Reliability Requirements. The

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 2-32 below. InnPower has met or exceeded the OEB minimum standards in all years.

Table 2-32: Historical Service Quality Metrics

Service Quality Metric	2021	2022	2023	2024	2025	Minimum Standards
Low Voltage Connections	95.83%	95.83%	99.42%	99.63%	97.76%	> 90%
High Voltage Connections	-	-	-	-	-	> 90%
Telephone accessibility	82.96%	82.96%	79.26%	82.45%	58.50%	> 65%
Appointments met	100.00%	100.00%	100.00%	100.00%	100.00%	> 90%
Written response to enquiries	99.56%	99.56%	99.68%	93.58%	82.35%	> 80%
Emergency Urban Response	-	-	-	-	-	> 80%
Emergency Rural Response	98.04%	98.04%	100.00%	100.00%	100.00%	> 80%
Telephone call abandon rate	1.58%	1.58%	3.65%	4.93%	14.71%	< 10%
Appointment scheduling	100.00%	100.00%	99.89%	99.91%	100.00%	> 90%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	> 100%
Reconnection Performance Standard	100.00%	100.00%	100.00%	100.00%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	-	-	-	100.00%	100.00%	> 90%
Billing Accuracy	99.83%	99.87%	99.93%	99.75%	99.45%	> 98%

A full discussion of the Service Quality Metrics can be found in InnPower's Distribution System Plan Section 5.2.3.2.1 Service Quality Requirements.

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Appendix 1 InnPower Distribution System Plan

Appendix 1 InnPower Distribution System Plan

InnPower Corporation

Distribution System Plan

2027 Cost of Service Application

Historical Period:

2022–2026

Forecast Period:

2027–2031

Date

July 27, 2026

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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
AI	Artificial Intelligence
AM	Asset Management
BATU	Barrie Area Transformer Upgrade
BBA	BBA Incorporated
BCA	Benefit-Cost Analysis
BESS	Battery Energy Storage Systems
CAIDI	Customer Average Interruption Duration Index
CDM	Conservation Demand Management
CHEC	Cornerstone Hydro Electric Concepts Association
CHI	Customer Hours Interrupted
CI	Customers Interrupted
CIS	CIS Customer Information System
CoS	Cost of Service
CSA	Canadian Standard Association
CVOR	Commercial Vehicles Operators Registration
DAI	Data Availability Index
DC	Direct Current
DCF	Discounted Cash Flow
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DESN	Dual Element Spot Network
DGA	Dissolved Gas Analysis
DIR	Distribution Inspection Requests
DS	Distribution Substations
DSC	Distribution System Code
DSP	Distribution System Plan
EDA	Electricity Distributors Association
ERP	Enterprise Resource Planning
ESA	Electrical Safety Authority
EV	Electric Vehicle
FLISR	Fault Location, Isolation, and Service Restoration
GIS	Geographic Information System
GIS-UNM	Geographic Information System Utility Network Model
GPS	Global Positioning System
GS	General Service
HI	Health Index
HONI	Hydro One Networks Inc.
HSE	Health, Safety and Environmental
IEP	Integrated Energy Plan
IESO	Independent Electricity System Operator

Acronym	Meaning
Innisfil Hydro	Innisfil Hydro Distribution Systems Limited
InnPower	InnPower Corporation
IR	Infrared
IRRPS	Integrated Regional Resource Plans
IT	Information Technology
LDC	Local Distribution Company
LiDAR	Light Detection and Ranging
LOS	Loss of Supply
MCR	Municipal Comprehensive Review
MED	Major Event Detail
MEARIE	Municipal Electric Association Reciprocal Insurance Exchange
MTO	Ministry of Transportation
NA	Need Assessment
NWA	Non-Wire Alternative
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OH	Overhead
OM&A	Operating, Maintenance, and Administration
PCB	Polychlorinated Biphenyl
REG	Renewable Energy Generation
RIP	Regional Infrastructure Plan
ROE	Return on Equity
ROW	Right of Way
RPPAG	Regional Planning Process Advisory Group
RRF	Renewed Regulatory Framework
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SD	Subdivision
SGBM	South Georgian Bay-Muskoka
SQR	Service Quality Requirements
TS	Transformer Station
UG	Underground
USF	Utilities Standards Forum
VA	Vulnerability Assessment
VASH	Vulnerability Assessment and System Hardening
VLF	Very Low Frequency

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 is 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 is 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, 2025 Edition for 2026 Rate Applications, dated December 16, 2025 (the "Filing Requirements") as part of its 2027 Cost of Service (CoS) Application (the Application). InnPower retained BBA Inc. (BBA) 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 2022 to 2026, and a forecast period of 2027 to 2031, with 2027 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 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, including 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 $81,000, 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.

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. This 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 be used to inform and potentially support any requests for incremental capital module (ICM) funding during the 5-year DSP term.

5.2.1.1 Description of the Utility Company

Brief overview of the LDC (regions served, size of service area, total number of customers).

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 is also a member of Grid Smart Citym a major collaborative group of 21 LDCs across Ontario. 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 24,000 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.

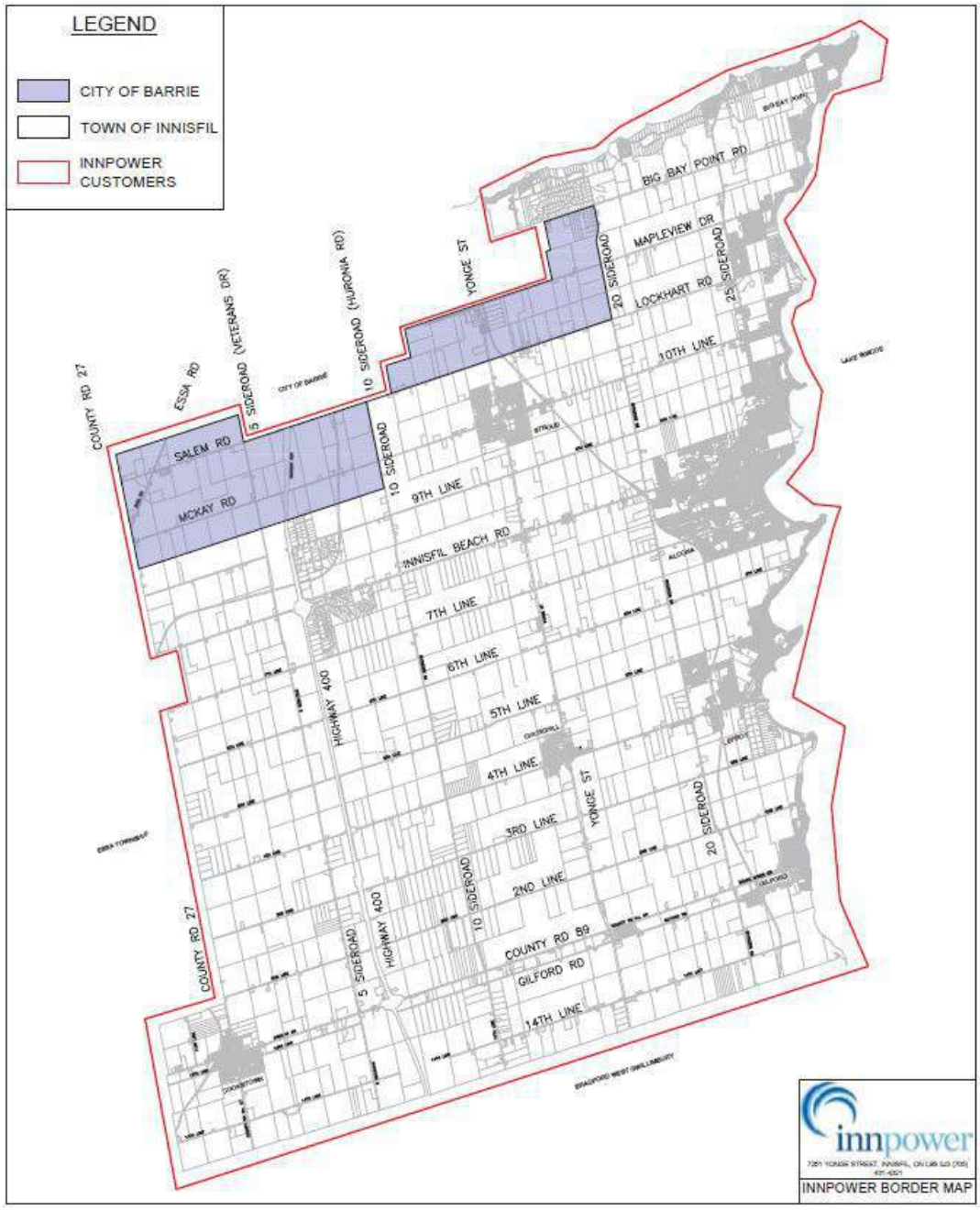

Figure 5.2-1: InnPower's Service Territory

InnPower 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 2027-2031 Business Plan*, attached as appendix 1-7 to this Cost-of-Service application.

- **Service Quality, Reliability and Safety:** We will continue to foster a culture that recognizes service quality, reliability, and safety as paramount to the utility's success. We will improve system performance through ongoing maintenance, targeted system investments, and increased automation to support reliability and outage response. We will also strengthen health and safety practices and enhance emergency preparedness and communications with customers and stakeholders.
- **Enterprise Resiliency:** We will strengthen organizational resiliency to better anticipate and respond to operational and enterprise risks. We will develop workforce capacity, improve knowledge transfer and documentation practices, and enhance cybersecurity to protect critical systems and infrastructure.
- **Operational Optimization:** We will advance operational efficiency through the use of digital tools and emerging technologies, including artificial intelligence. We will improve project delivery, standardize processes, and modernize systems to enhance overall performance.
- **Financial Viability:** We will maintain financial sustainability through disciplined capital planning, improved financial controls, and strategies that support growth while managing affordability. We will continue to strengthen long-term financial stability.
- **Employee Development and Engagement:** We will enhance employee engagement, development, and organizational effectiveness. We will invest in training and development and strengthen performance management practices to support a high-performing workforce.

- **Customer Satisfaction and Engagement:** We will improve customer satisfaction through enhanced service delivery, digital engagement tools, and stronger communication. We will also continue to support sustainability and energy conservation initiatives.
- **Stakeholder Understanding and Support:** We will strengthen stakeholder relationships through improved engagement, communication, and collaboration. We will enhance key account support and continue working with industry partners to support shared learning and coordinated response.
- **Infrastructure Strategy and Performance:** We will improve infrastructure performance through effective asset management, data-driven decision-making, and continued investment in system reliability, resilience, and operational efficiency.

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					Forecast				
	2022	2023	2024	2025	2026 [1]	2027	2028	2029	2030	2031
System Access (gross)	11,647	18,148	19,869	27,172	22,447	25,543	22,545	13,925	12,920	13,012
System Renewal (gross)	6,895	3,589	8,379	5,484	1,682	2,749	6,092	5,435	6,670	5,637
System Service (gross)	954	6,913	5,440	5,281	7,142	8,901	8,579	2,920	12,930	11,641
General Plant (gross)	1,020	1,508	969	850	1,654	3,368	3,398	1,412	1,936	2,271
Gross Capital Expenses	20,516	30,158	34,657	38,787	32,926	41,071	40,613	23,692	34,456	32,560
Contributed Capital [2]	(9,579)	(13,251)	(17,062)	(19,831)	(19,772)	(19,315)	(15,438)	(6,323)	(5,121)	(5,044)
Net Capital Expenses after Contributions	10,936	16,907	17,594	18,955	13,154	21,246	25,175 [3]	17,368 [4]	29,335 [5]	27,516
System O&M	2,318	2,734	3,220	3,459	3,766	4,010	4,371	4,576	4,841	5,104

[1] 2026 contains no actual expenditures and reflects budgeted amounts only
[2] Contributed capital includes system access projects such as Hewitt, Salem, and other works that are 100% recoverable, as well as road authority projects that are 50% recoverable through labour and labour saving devices contributions.

[3, 4, 5] Forecast capital expenditures and contributed capital vary year over year due to the timing of specific projects, including the completion of Hewitt and Salem works, changes in station rehabilitation activities, fleet additions, and the commencement of the transmission station (TS) project in 2030.

5.2.1.2.1 System Access

Summary of drivers & major projects proposed.

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. InnPower is engaged in additional discussions with potential developers, that may also be connected in the later years of the DSP. 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 sustained at high levels of net capital expenditures before and after contributions, 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. These developments are driven by external developers and were not known at the time of the last application.
    - 23 subdivision developments energized between 2023 and 2025 with over 3,400 anticipated connections.
- 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. These are third-party driven projects and obligations under the Public Service Works on Highways Act.
    - InnPower uses the best information available to determine likelihood of projects, however, as these are third-party driven largely out of InnPower's control.
    - Major projects include:
        - **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.

5.2.1.2.2 System Renewal

Summary of drivers & major projects proposed.

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 June 2026, 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

Summary of drivers & major projects proposed.

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.

Over the forecast period, System Service investments are driven primarily by the Barrie Area Transmission Upgrade (BATU) project and a new transformer station project in the Innisfil area, both required to support regional capacity expansion and load growth. BATU involves upgrading existing 115 kV transmission circuits to 230 kV between Essa TS and Barrie TS, along with associated station expansions, and remains a key driver of System Service investment due to updated schedule and cost forecasts. The new transformer station project will leverage the upgraded transmission system and is intended to provide additional local capacity.

5.2.1.2.4 General Plant

Summary of drivers & major projects proposed.

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, engineering IT, process improvements, ongoing improvements to buildings and fixtures, and investments in measuring tools and equipment, and fleet replacement.

5.2.1.3 Key Changes since Last DSP Filing

Where applicable, an indication of important changes since the last DS Plan filing.

InnPower is pursuing an early rebasing of its distribution rates to address a structural timing mismatch between rapid capital investment and revenue realization. The utility is experiencing unprecedented, policy-driven growth within its service territory, largely driven by third-party developers responding to provincial housing mandates. Between 2023 and 2025 alone, InnPower energized 23 subdivision developments, with anticipated residential and industrial connections of almost 3,500 units. However, due to a sharp shift in the economy, these lots are not being connected as quickly as projected, causing a severe time-delay in revenue recognition.

The volume and timing of these projects are dictated by external market forces and developer schedules, this growth trajectory has been outside of InnPower's control and impossible to accurately forecast under our current rate timeline. Yet, InnPower was mandated to electrify these developments and assume long-term ownership of the resulting infrastructure. This has expanded our capital baseline significantly ahead of schedule, forcing substantial upfront investment while the expected distribution revenue remains stalled. Early rebasing is critical to realign our rate structure with this accelerated infrastructure footprint and ensure ongoing financial sustainability.

InnPower last rebased its rates in 2024 under the Price Cap IR framework, with the current term extending to 2028. Early rebasing is intended to ensure InnPower can continue to meet its system expansion and reliability obligations while maintaining financial sustainability.

Additionally, InnPower is exploring the use of artificial intelligence tools to support asset analysis and decision-making processes. This includes the use of AI-enabled software, such as Senpilot, to assist in asset condition assessments, with all outputs subject to review and validation by InnPower staff.

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 2027 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*:

- **Customer Focus:** Services are provided in a manner that responds to identified customer preferences.
- **Operational Effectiveness:** Continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives.
- **Public Policy Responsiveness:** Utilities deliver on obligations mandated by the government (i.e.: in legislation and regulatory requirements imposed further to Ministerial directives to the Board).
- **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 2027 to 2031 Business Plan* (attached as Appendix 1-7).

5.2.2 Coordinated Planning with Third Parties

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

For consultations that affect the DSP, a distributor should provide:

- *an overview of the consultations,*
- *relevant material supporting the effects the consultations had on the DSP*

An overview of any consultation 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 (e.g., customers, transmitter, IESO).

A distributor should file the most recent Regional Plan (i.e., 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.

<<Note: number & list of engagements may vary from one utility to the next>>

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 Customer 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. Participants normally include a mix of residential, general service, industrial and commercial customers. Reactive engagements are driven by customers feedback and priority survey data, to address client needs and establish sustainable, forward-looking solutions.

Brief Description of Consultation

Customer engagement is conducted through InnPower's website, social media channels, customer engagement events, and customer surveys. InnPower utilizes surveys to educate, inform, and solicit customer input regarding current operations, future plans, and investment priorities. InnPower distributes surveys to gather feedback, identify opportunities for improvement, and ensure continued delivery of high-quality customer service.

In 2026, InnPower conducted a Customer Priorities Survey from March 12, 2026 to March 26, 2026. The Survey. The survey received 146 responses, primarily from residential customers. Customers identified affordability, reliability, outage response, outage communications, and infrastructure

resilience as their highest priorities. Specifically, 90% of respondents identified keeping electricity costs affordable as a priority, while 58% selected maintaining and upgrading equipment to ensure safe and reliable electricity service, 55% selected strengthening infrastructure to withstand storms and extreme weather, 53% selected improving outage response and restoration times, and 50% selected improving communication during outages. Additionally, 25% identified increased vegetation management as a priority.

InnPower also conducted a Customer Input Survey in 2026 to gather more detailed feedback regarding service priorities and improvement opportunities. The survey received 25 responses from customers across the service territory, with the majority identifying System Reliability and Maintenance as the most important area of focus. Among those selecting reliability and maintenance, the most commonly identified priorities were upgrading and replacing aging equipment, tree trimming and vegetation management, and improving reliability in rural and remote areas. Customers also indicated that they prefer to receive outage updates through text messages, email notifications, and website outage maps, reinforcing the importance of digital communications during outage events.

Consultation Outcomes and Impact on this DSP

Customer feedback has been integrated into the preparation of this DSP. The survey results demonstrate that customers place the highest value on affordability, reliability, outage response and communications. In particular, more than half of the respondents identified equipment renewal, storm hardening, and improved outage response as key priorities. These findings support InnPower's continued investment in System Renewal programs to replace aging and deteriorated assets which included poles, transformers, reclosers, switches, and switchgear.

Customer feedback also supports investments that improve restoration performance and enhance system resilience. Priorities identified through surveys, which include maintaining and upgrading equipment, improving outage response times, increasing vegetation management activities, and strengthening infrastructure against severe weather, align directly with InnPower's planned reliability and resilience programs. These investments are intended to reduce outage frequency and duration while maintaining a safe and reliable distribution system.

Consistent with customer feedback, InnPower will continue to focus on affordability, reliability, and customer service through prudent asset management, preventative maintenance programs, vegetation management, customer education initiatives, and ongoing customer engagement activities. Customer input will continue to be used to guide investment decisions and ensure alignment between capital spending priorities and customer expectations.

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, every six weeks. InnPower also maintains active communication, emails and meetings with the developer groups between those 6-week status meetings. Monthly project status and financial updates are also sent to Hewitt and Salem developers. 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 2,850 new connections (residential, institutional, commercial, and industrial) are expected to be in service by 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. Phase 4 is expected to be energized in 2026.
- **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. A hotel and conference centre is expected to be energized in 2027.
- **Hewitt Creek**: A subdivision development with an anticipated build-out of 900 homes on Mapleview Drive.
- **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.
- **Belle Aire Developments**: A subdivision development with an anticipated build-out of 200 homes and commercial units on Belle Aire Beach Road.
- **Watersand**: A multi-phase subdivision development with an anticipated build-out of 762 homes on Mckay Road West.

- **Mattamy Salem**: A multi-phase subdivision development with an anticipated build-out of 758 homes in South Barrie.

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. Beginning in 2026, this coordination has been further strengthened through biannual meetings involving all road authorities and utilities to review and align upcoming projects, with the goal of improving timing coordination and optimizing the allocation of funding where possible. This collaborative approach allows for better alignment of project timelines—for example, advancing or deferring planned road relocations to coincide with scheduled asset replacement work—thereby improving efficiency and minimizing duplication of effort.

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).

Hewitt and Salem developments continue to progress in alignment with developer-driven growth requirements. Coordination is ongoing to ensure that new pole line installations are designed to accommodate future road widening requirements and minimize the need for future relocations.

A few of the larger road authority works and municipality developments happening in InnPower's service area include but are not limited to.

- **County Road 4 Widening (Phases 3 to 7):** Multi-phase utility relocations to support roadway widening across multiple segments. Phase 3 is scheduled between InnPower's southern limit and County Road 89 (2026–2027), Phase 4 between the InnServices building and 9th Line (2027), Phase 5 in Stroud (2027–2028), and Phases 6 and 7 between the InnServices building and County Road 89 (2028–2029).
- **County Road 53 Widening:** Relocation works between County Road 21 and the Barrie city limits, scheduled for 2026.
- **County Road 27 Widening:** Relocation works between County Road 21 and County Road 90, scheduled for 2028–2029.
- **County Road 54 and Line 6 Intersection (Innisfil):** Relocation works at the identified intersection scheduled for 2031.

In addition to the above confirmed projects, the Town and County have identified further potential initiatives with variable timing, including the Webster and 20th Sideroad roundabout (anticipated 2026), the 7th Line corridor from 20th Sideroad to the lake (multi-year works potentially commencing around 2027), and 25th Sideroad (Innisfil Beach Road to Big Bay Point) multi-use path installation. These projects remain subject to final design and scheduling confirmation.

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, Hydro One Networks Inc. (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 5.2-2. 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 5.2-2: 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 5.2-3). InnPower is embedded within the Barrie/Innisfil Sub-region.

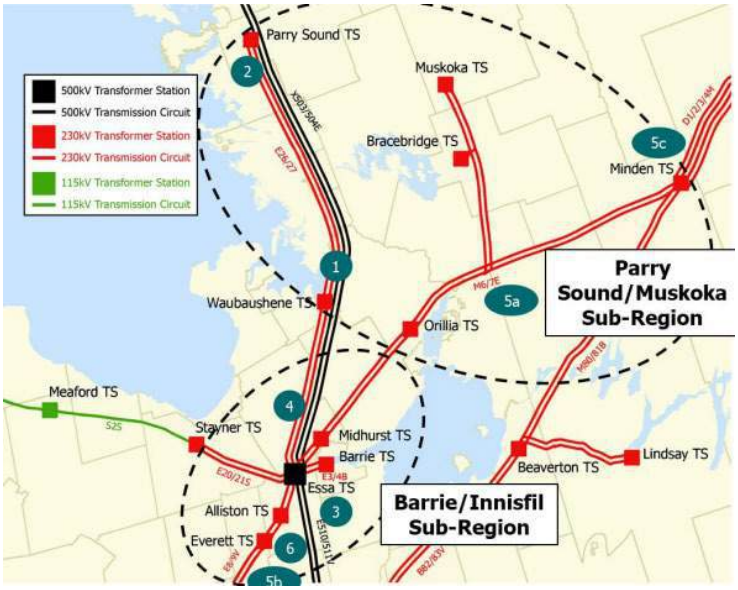

Figure 5.2-3: Barrie/Innisfil sub-region

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 second cycle of South Georgian Bay–Muskoka regional electricity planning commenced in January 2020 with a Needs Assessment issued by Hydro One in April 2020, which identified capacity constraints and the need for coordinated regional solutions; its findings informed the IESO's Scoping Assessment released in November 2020, which directed further sub-regional planning through Integrated Regional Resource Plans (IRRPs). The Barrie/Innisfil IRRP, released in May 2022, along with the 2021 Innisfil Area Supply Alternatives Report prepared by Hydro One with support from Alectra and InnPower, concluded that the existing 44 kV supply from Barrie TS would be inadequate to meet forecast load growth in Innisfil, with demand exceeding available capacity well before 2030. These studies collectively identified a new 230 kV-supplied transformer substation—specifically a 230/27.6 kV station connected via a tap to the E28B/E29B circuits enabled by the BATU project—as the preferred near- to medium-term solution, while also recommending continued monitoring of demand management, electrification trends, and non-wires alternatives. This recommendation was formally incorporated into the December 2022 South Georgian Bay–Muskoka Regional Infrastructure Plan, which designated InnPower to lead the development and implementation of the new 230/27.6 kV 2×83 MVA DESN Transformer Station.

The subsequent cycle of regional electricity planning is currently in progress. Hydro One Networks Inc. published the South Georgian Bay–Muskoka Needs Assessment in August 2025, which identified a number of system needs requiring further regional coordination. Building on the outcomes of the Needs Assessment, the IESO released the draft Scoping Assessment report in October 2025 to evaluate the appropriate planning approach for addressing the identified needs. The draft Scoping Assessment concludes that an Integrated Regional Resource Plan (IRRP) is the preferred planning approach and recommends that the IRRP process be initiated immediately following the completion of required approvals, with an anticipated completion timeframe of approximately 12 months.

5.2.2.4.1 Needs Assessment

A Needs Assessment (NA) was undertaken by Hydro One Networks Inc. (HONI) for the South Georgian Bay–Muskoka region as part of the third cycle of regional electricity planning and was published in August 2025. The purpose of the NA was to identify new and emerging electricity system needs in the region, reaffirm needs identified in previous planning cycles, and determine the appropriate planning path forward for each need—either through local planning, regional infrastructure planning, or further regional coordination.

The NA considered a range of technical inputs, including:

- Updated summer and winter load forecasts for all transformer stations in the region, incorporating municipal inputs and sensitivity scenarios;
- Station capacity, transmission supply capability, system reliability, and operational considerations, including major transmission and station assets approaching end of life;
- Planned and foreseeable transmission and distribution investments relevant to addressing regional electricity needs.

Based on this assessment, the NA identified several station capacity, transmission supply, and bulk system considerations that require further regional coordination. In particular, the NA reaffirmed the need for coordinated planning to address forecast load growth and supply capacity constraints affecting parts of the region, including needs relevant to the Barrie/Innisfil area. The NA concluded that these needs should proceed to the next phase of the regional planning process through an IESO-led Scoping Assessment.

Purpose:
To identify new electricity system needs and reconfirm previously identified needs that require further regional coordination.

Participants:
HONI, IESO, Hydro One Distribution, Alectra Utilities, InnPower, Orangeville Hydro, Elexicon, Lakeland Power, EPCOR, Newmarket-Tay Hydro, and Wasaga Distribution.

Status: Complete.

Deliverables: NA Report issued by HONI on August 27, 2025 (see Appendix B)

5.2.2.4.2 Scoping Assessment

A Scoping Assessment Outcome Report was developed for the South Georgian Bay–Muskoka (SGBM) region and released by the IESO in October 2025 as part of the third cycle of regional electricity planning. The purpose of the Scoping Assessment was to review the needs identified in the August 2025 NA and determine the most appropriate planning approach to address those needs.

The Scoping Assessment evaluated the nature, timing, geographic distribution, and interdependencies of identified station capacity, transmission supply, bulk system, and asset replacement needs. Consideration was also given to long-term load forecast uncertainty, potential interactions with upstream bulk power system constraints, and the opportunity to assess a range of wires and non-wires alternatives.

Based on this assessment, the IESO concluded that an IRRP is the preferred planning approach for addressing the identified needs. Unlike previous planning cycles, the Scoping Assessment determined that the needs are best addressed through a single IRRP covering the entire South Georgian Bay–Muskoka region, rather than through separate sub-regional plans, due to system interdependencies and bulk system considerations.

The Scoping Assessment also established the Terms of Reference for the forthcoming IRRP and confirmed the composition of the Technical Working Group, which includes the IESO, Hydro One Transmission and Distribution, and affected Local Distribution Companies, including InnPower.

Purpose:
To review the needs identified in the Needs Assessment and determine the most appropriate planning approach, including whether to proceed with local planning, regional infrastructure planning, or an Integrated Regional Resource Plan.

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

Status:
Draft – Complete.

Deliverables:
Draft Scoping Assessment Outcome Report for the South Georgian Bay–Muskoka Region, issued October 31, 2025. (see Appendix C)

5.2.2.4.3 Next Steps

Following the completion of the Scoping Assessment, the next phase of the regional planning process will be the development of an Integrated Regional Resource Plan (IRRP) for the South Georgian Bay–Muskoka region. The IRRP will assess regional electricity needs over a 20-year horizon and evaluate a range of coordinated wires and non-wires alternatives to address identified station capacity, transmission supply, bulk system, and asset condition needs. Upon completion of the IRRP and confirmation of preferred wire-based solutions, a Regional Infrastructure Plan (RIP) will be developed by the transmitter to advance detailed scope, cost, and implementation timelines for recommended infrastructure investments. These steps will ensure that regional needs are addressed in a coordinated, cost-effective, and reliability-focused manner, consistent with the Ontario Energy Board–mandated regional planning framework.

5.2.2.5 Telecommunication Entities

In 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 information in its capital plan.

Per the new telecom regulations, the distributor should provide:

- *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 5.2-2 summarizes the formal consultations with communication companies that InnPower has organized and been involved in since the last DSP filing.

Table 5.2-2: 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

Telecommunication Company	Consultation Frequency	Participants
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.

5.2.2.6 Renewable Energy Generation (REG)

A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are no REG investments in the region.

There are no Renewable Energy Generation (REG) investments planned within InnPower's service territory for the 2026–2031 forecast period; therefore, this section is not applicable.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

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

5.2.3.1.1 Objectives for Continuous Improvement Set out in Last DSP Filing

<<Note: This section is only required if LDC has set objectives for continuous improvement in the previous DSP filing (that differ from metrics already recorded in the performance scorecard, which are included in the following section)>>

InnPower did not set any other objectives not covered by the performance scorecard in its previous DSP filing.

5.2.3.1.2 Performance Scorecard

Explanations required for any objectives that have not been achieved, how it affects the DSP (if applicable) and improvements implemented to address/achieve these objectives.

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 5.2-3 summarizes InnPower's performance during historical years from 2021 to 2025. Explanations for any missed targets, including the impact on the DSP and any associated improvements, are detailed in the following sub-sections.

Table 5.2-3: DSP Performance Measures

Performance Outcome	Measure	Metric	2021	2022	2023	2024	2025	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	99.50%	95.83%	99.42%	99.63%	97.76%	> 90%
		Scheduled Appointments Met on Time	100.00%	100.00%	100.00%	99.76%	100.00%	> 90%
		Telephone Calls Answered on Time	90.18%	82.96%	79.26%	82.45%	58.50%	> 65%
	Customer Satisfaction	First Contact Resolution	99.95	99.90	99.90	99.91	99.80%	-
		Billing Accuracy	99.83%	99.87%	99.93%	99.75%	99.45%	98%
		Customer Satisfaction Survey	B+	B+	B+	B+	C+	-
Operational Effectiveness	Safety	Level of Public Awareness	83.00%	83.00%	83.00%	83.00%	83.00%	-
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
		Number of General Public Incidents	0	0	2	1	0	0
		Rate per 10, 100, 1000 km of line	0.000	0.000	1.366	0.558	0.000	0.191
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	1.78	1.04	1.29	1.6	1.67	1.49
		Ave. Number of Times that Power to a Customer is Interrupted	0.7	0.87	0.87	1.64	1.18	0.83
	Asset Management	Distribution System Plan Implementation Progress	109.0%	62.0%	90.6%	156.1%	163.6%	-
	Cost Control	Efficiency Assessment	3	3	3	3	3	3
		Total Cost per Customer	$897	$961	$1,122	$760	$723	No target
		Total Cost per km of Line	$12,072	$13,471	$13,986	$16,211	$18,977	No target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation CIA Completed on Time	-	-	-	-	-	-
		New Micro-embedded Generation Facilities Connected on Time	-	-	-	100.00%	100.00%	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	0.48	1.03	0.42	0.49	0.85	-
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	1.27	1.09	1.21	1.28	1.59	-
		Regulatory ROE – Deemed (included in rates)	8.78%	8.78%	8.78%	9.21%	9.21%	-
		Regulatory ROE - Achieved	9.26%	12.82%	10.04%	6.77%	4.87%	-

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

In 2023, InnPower had two serious ESA incidents, as per the ESA guidelines, and continues to report zero fatalities within its service territory. Both incidents were caused by a tree falling on an energized line. InnPower continues to perform regular site visits and rigorous safety training to identify potential hazards and communicate findings and recommendations to all staff and the public. Correspondingly, InnPower exceeded the target for the "Rate per 10, 100, or 1,000 km of line" metric in 2023. As this metric is directly correlated to the number of general public incidents and normalized based on the size of the distribution system, the increase in the rate reflects the occurrence of the incidents described above.

In 2024, InnPower reported one serious accident caused by a tree falling on an energized line, though it maintained zero fatalities and continues to strengthen safety through site visits and safety training. Correspondingly, InnPower also exceeded the target for the "Rate per 10, 100, or 1,000 km of line" metric in 2024, reflecting the incident noted above. Additionally, the average outage duration was 1.60 hours, exceeding the 1.49 target, mainly due to wildlife interference, equipment defects, vegetation encroachment, and adverse weather. Customers experienced 1.64 sustained interruptions in 2024, exceeding the 0.83 target. The underlying causes are consistent with those outlined in the SAIDI discussion above. InnPower strives to provide reliable service and continues investing in vegetation management and smart grid technologies to improve reliability. InnPower is increasing the vegetation management cycle from 4-years to 3-years to adequately address overgrowth and reduce the impact during adverse weather events.

The average outage duration in 2025 was 1.67 hours, exceeding the target of 1.49, primarily caused by defective equipment, vegetation encroachment and unknown causes. Additionally, the 0.83 target for SAIFI was also exceeded in 2025 with 1.18 sustained interruptions mainly due to adverse weather, vegetation encroachment and foreign interferences. These performance gaps highlght the need for increase system renewal capital to replace aging, defect-pront assets and strengthen network resilience against environmental pressures.

In 2025, InnPower missed the target for Telephone Calls Answered on Time. This is due to elevated call volumes and temporary resourcing constraints. In particular, the March 2025 ice storm resulted in a significant surge in customer inquiries related to outages, restoration efforts, and service updates, exceeding normal operating capacity. Concurrent staffing pressures, including vacancies and onboarding of new employees, further impacted response times. InnPower has since taken steps to address these challenges, including targeted hiring, enhanced training, process and technology improvements, and providing alternative options for customers to obtain information and updates; to better manage call volumes and improve customer response performance going forward. To sustain and build upon these efforts, further mitigation will be supported by the additional resources requestsed in this rebasing application.

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, must 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.

5.2.3.2.1 Service Quality Requirements

Explanations required for any underperformance, missed targets, material changes or declining trends, and whether and how the DSP addresses these issues.

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 5.2-4 below.

Table 5.2-4: Historical Service Quality Metrics

Service Quality Metric	2021	2022	2023	2024	2025	Minimum Standards
Low Voltage Connections	95.83%	95.83%	99.42%	99.63%	97.76%	> 90%
High Voltage Connections	-	-	-	-	-	> 90%
Telephone accessibility	82.96%	82.96%	79.26%	82.45%	58.50%	> 65%
Appointments met	100.00%	100.00%	100.00%	100.00%	100.00%	> 90%
Written response to enquiries	99.56%	99.56%	99.68%	93.58%	82.35%	> 80%
Emergency Urban Response	-	-	-	-	-	> 80%
Emergency Rural Response	98.04%	98.04%	100.00%	100.00%	100.00%	> 80%
Telephone call abandon rate	1.58%	1.58%	3.65%	4.93%	14.71%	< 10%
Appointment scheduling	100.00%	100.00%	99.89%	99.91%	100.00%	> 90%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	> 100%
Reconnection Performance Standard	100.00%	100.00%	100.00%	100.00%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	-	-	-	100.00%	100.00%	> 90%
Billing Accuracy	99.83%	99.87%	99.93%	99.75%	99.45%	> 98%

A review of the service quality indicators data above indicates that InnPower has exceeded SQR expectations for almost all historical years, with no missed targets except for Telephone Accessibility and Telephone Call Abandon Rate in 2025. The reasons for these missed targets are due to elevated call volumes and temporary resourcing constraints. Particularly after the March 2025 ice storm resulted in a significant surge in customer inquiries related to outages, restoration efforts, and service updates,

which exceeded normal operating capacity. Concurrent staffing pressures, including vacancies and onboarding of new employees, further impacted response times.

5.2.3.2.2 Reliability Requirements

Explanations required for any underperformance, missed targets, material changes or declining trends, and whether and how the DSP addresses these issues.

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 Table 5.2-5, Table 5.2-6, Figure 5.2-4, Figure 5.2-5, and Figure 5.2-6 below.

Table 5.2-5: Historical Reliability Performance Metrics – All Cause Codes

Metric	2021	2022	2023	2024	2025	Average
SAIDI	3.73	2.52	1.83	2.11	52.16	12.47
SAIFI	1.37	1.58	1.17	2.48	2.63	1.85
CAIDI	2.71	1.60	1.56	0.85	19.83	5.31

Table 5.2-6: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2021	2022	2023	2024	2025	Average
Loss of Supply Adjusted *(including MEDs, Excluding LOS)*						
SAIDI	3.73	2.52	1.29	2.04	51.73	12.26
SAIFI	1.37	1.58	0.86	2.35	2.06	1.64
CAIDI	2.71	1.60	1.50	0.87	25.11	6.36
Major Event Days Adjusted (including LOS, excluding MEDs)						
SAIDI	1.78	1.04	1.83	1.67	2.09	1.68
SAIFI	0.70	0.87	1.17	1.77	1.75	1.25
CAIDI	2.54	1.19	1.56	0.94	1.20	1.49
Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)						
SAIDI	1.78	1.04	1.29	1.6	1.67	1.48
SAIFI	0.7	0.87	0.87	1.64	1.18	1.05
CAIDI	2.54	1.20	1.48	0.98	1.42	1.52

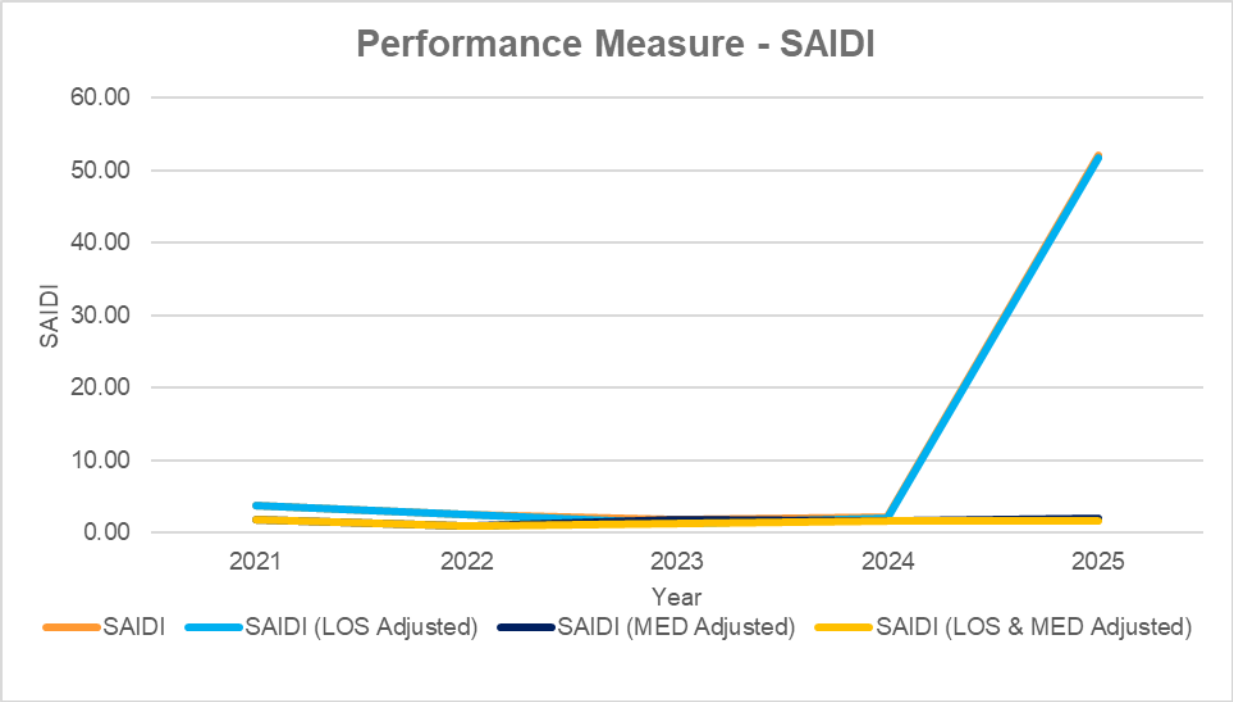

Figure 5.2-4: Performance Measure – SAIDI

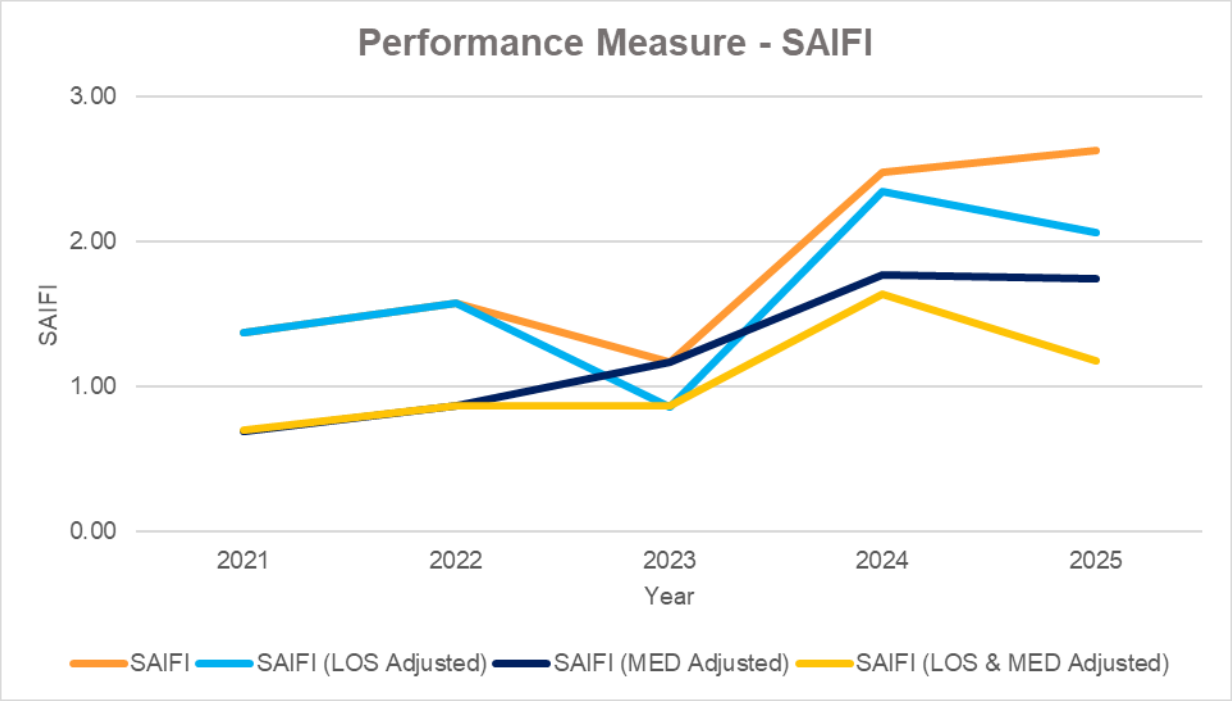

Figure 5.2-5: Performance Measure - SAIFI

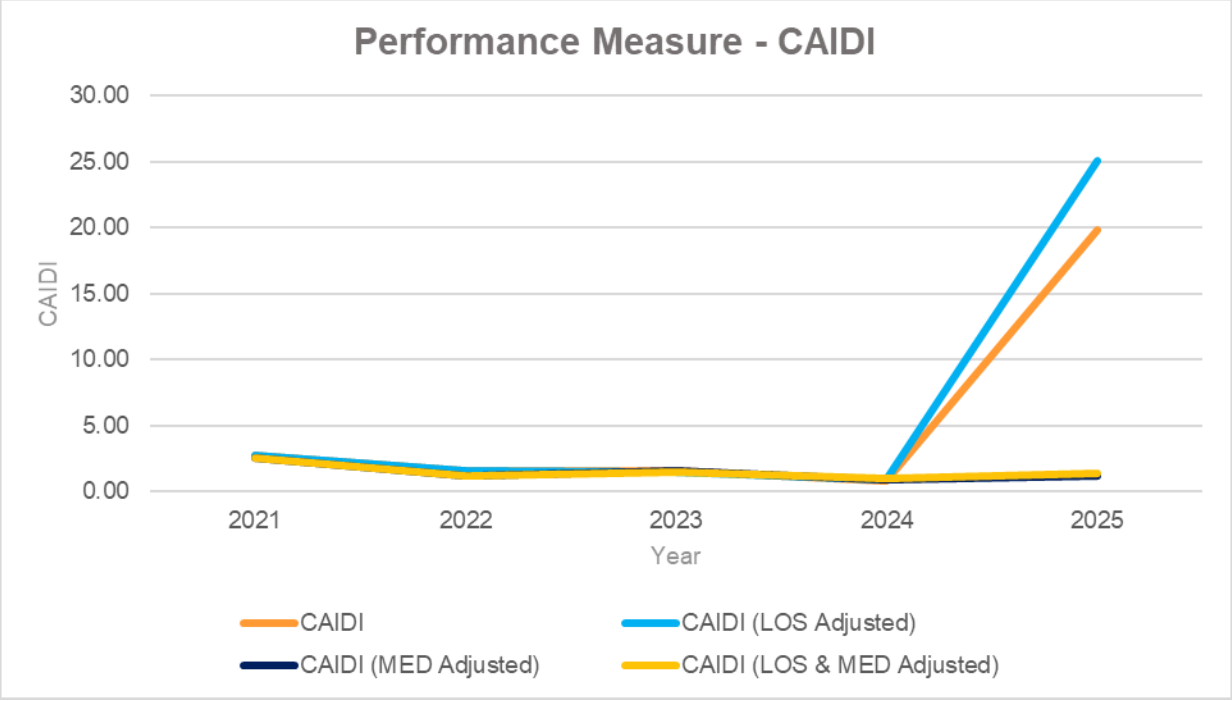

Figure 5.2-6: Performance Measure - CAIDI

InnPower's historical SAIDI and SAIFI (LOS and MED adjusted) performance have been lower than the distributor's targets with the exception of the recorded SAIDI and SAIFI in 2024 and 2025.

InnPower exceeded its SAIDI target mainly due to wildlife interference, equipment defects, vegetation encroachment, and adverse weather. Customers experienced 1.64 and 1.67 sustained interruptions in 2024 and 2025, exceeding the 0.83 target. The underlying causes are consistent with those outlined in the SAIDI discussion above.

InnPower uses the SAIDI, SAIFI and CAIDI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. InnPower strives to provide reliable service and continues investing in vegetation management and smart grid technologies to improve reliability. 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 24,000+ 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 2022-2026

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

Major Events

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. Table 5.2-7 and Table 5.2-8 provide a summary of InnPower’s Major Event Days (MEDs) over the historical period.

Table 5.2-7: Summary of MEDs over the Historical Period

Year	# of MEDs	Cause of MEDs
2021	4	Adverse weather—wind (three major events) and adverse weather—tornado
2022	1	Adverse Weather-Wind
2023	0	N/A
2024	1	Adverse Weather-Wind
2025	2	Adverse Weather-Freezing rain/Ice storm

Table 5.2-8: List of MEDs over the Historical Period

Date	Customer Base Interrupted	Description
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. 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
June 13, 2024	16,563	**Adverse Weather-Wind.** InPower's service area was impacted by a thunderstorm on June 13, 2024. The storm caused three of the four HONI feeders supplying our area to lockout around 8:14 PM, affecting 15,799 customers. Power was restored to 15,292 customers on Barrie M3 and Alliston M1 within 10 minutes. However, restoration of Alliston M4, affecting 507 customers, took longer until HONI cleared the line by 3:35 AM the next day. Power was restored to 111 of those 507 customers earlier at 1:15 AM but six crews continued through the night working until 6:00 AM the next day. IPC Operations and a team from third party contractor resumed the process. This seamless handover ensured continuous restoration efforts throughout the night with subsequent crews taking over around 4:00PM until late evening. During this response, crew restored power to 570 customers (in addition to

Date	Customer Base Interrupted	Description
		those affected directly by loss of supply), replaced two storm-damaged poles, conducted 20 inspections, removed 12 trees/branches from power lines, and issued 6 supporting guarantees. Notably, five of six these guarantees were reconnected by the end of the day or the following day, minimizing customer inconvenience.
March 29, 2025	21,200	**Adverse Weather-Freezing rain/Ice storm.** On March 29, 2025 at 08:00 am severe freezing rain resulted in wide scale outages across InnPower's entire service territory. The majority of InnPower's system is overhead and much of this is in close proximity to trees. The extreme conditions caused many trees to fall into the lines, causing critical feeders to trip out. In addition there were several broken poles, insulators and conductors throughout the area. InnPower experienced a loss of supply as HONI also had wide scale outages. Through a dedicated response effort including all internal and many external crews, power was restored to all customers by April 4, 2025.

For each cause of interruption, a distributor shall, 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*

Outages Experienced by Cause Codes

Table 5.2-9 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 5.2-9: Number of Outages (2021-2025)

Categorization	2021	2022	2023	2024	2025
All interruptions	181	195	196	250	193
All interruptions excluding LOS	181	195	191	248	190
All interruption excluding MED and LOS	177	194	191	234	189

Outages Experienced

Table 5.2-10 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 5.2-10: Outage Numbers by Cause Codes – Excluding MEDs

Cause Code	2021	2022	2023	2024	2025	Total Outages	%
0-Unknown/Other	21	17	27	27	33	125	12%

1-Scheduled Outage	74	71	64	68	54	331	33%
2-Loss of Supply	0	0	5	2	3	10	1%
3-Tree Contacts	21	25	23	38	23	130	13%
4-Lightning	2	1	1	0	0	4	0%
5-Defective Equipment	14	26	34	24	35	133	13%
6-Adverse Weather	18	28	18	47	8	119	12%
7-Adverse Environment	0	0	0	1	4	5	0%
8-Human Element	4	4	0	6	1	15	1%
9-Foreign Interference	27	23	24	37	31	142	14%
Total	181	195	196	250	192	1,014	100%

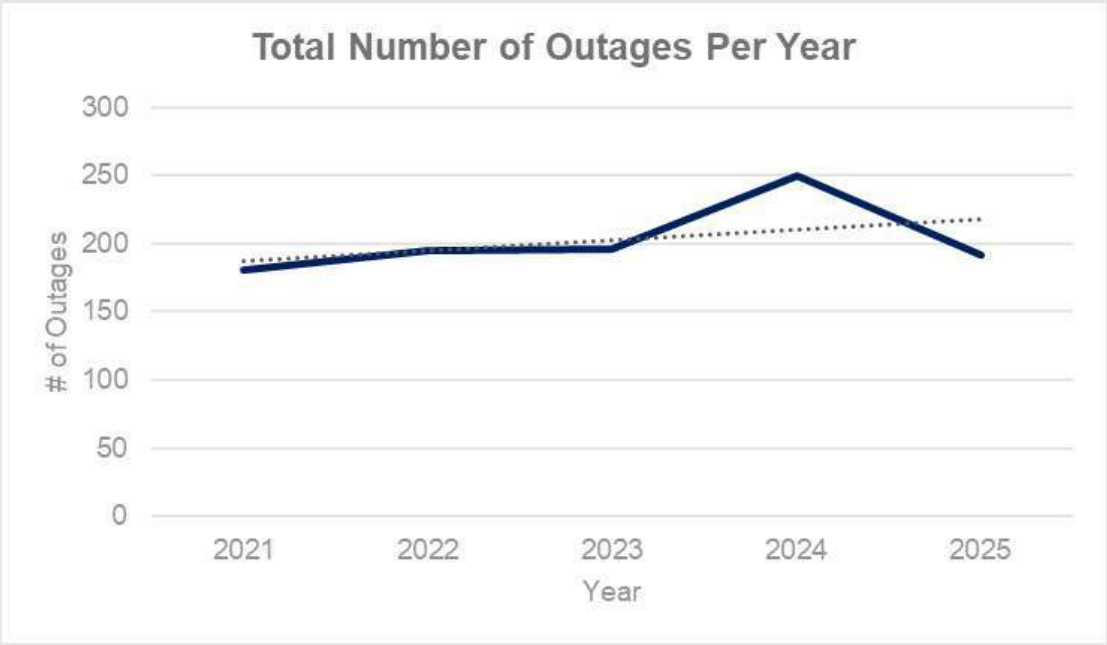

Figure 5.2-7: Total Number of Outages per Year

The total number of interruptions over the historical period is shown in Figure 5.2-7, varying from a low of 181 to a high of 250, with the trend increasing to 2024 then decreasing again in 2025. This represents an average of 0.496 to 0.685 interruptions per day.

A summary of the causes of outages within InnPower's system is presented in Figure 5.2-8, along with the percentage of overall outage incidents attributable to each cause type.

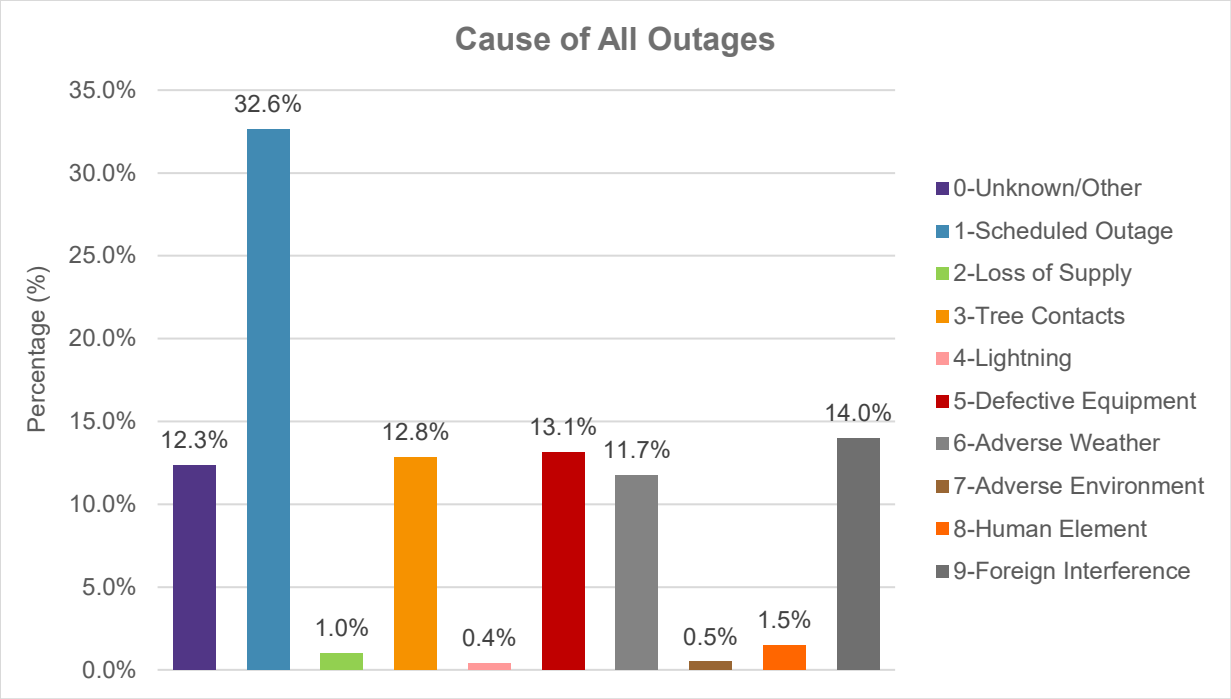

Figure 5.2-8: Percent of Outages by Cause Code

Scheduled outages, foreign interference, defective equipment, tree contacts, and unknown causes have been identified to be the five most common causes for outages, closely followed by adverse weather, on InnPower's distribution system over the historical period.

Together, these causes contributed to 85% of the total number of outages from 2021 to 2025, excluding MEDs. Scheduled outage is the top contributing cause to the total outages experienced by InnPower.

At 32.6%, Scheduled Outage is the 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.

At 14.0%, Foreign Interference is the second top contributing cause. Foreign interference 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.

Defective Equipment is the third top contributing cause, accounting for 13.1% of the total outages experienced. Defective equipment 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.

Tree Contacts are identified as the fourth top contributing cause to the total outages experienced by InnPower. Over the historical period, it has contributed to 12.8% of the total number of outages that occurred.

At 11.7%, Adverse Weather falls just outside of the top five contributing causes to total outages. 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.

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. Table 5.2-11, Table 5.2-12, Figure 5.2-9, and Figure 5.2-10 below provide the historical values and trends for both CI and CHI.

Table 5.2-11: Customers Interrupted Numbers by Cause Codes – Excluding MEDs

Cause Code	2021	2022	2023	2024	2025	Total CI	%
0-Unknown/Other	442	6,076	4,762	8,917	3,538	23,735	15%
1-Scheduled Outage	555	246	1,362	1,411	1,756	5,330	3%
2-Loss of Supply	0	0	6,624	2,975	13,661	23,260	14%
3-Tree Contacts	400	2,322	982	1,654	9,809	15,167	9%
4-Lightning	2	9	1	0	0	12	0%
5-Defective Equipment	3,456	609	1,926	1,778	5,171	12,940	8%
6-Adverse Weather	1,578	5,851	5,628	1,326	21,490	35,873	22%
7-Adverse Environment	0	0	0	57	6	63	0%
8-Human Element	30	2,068	0	1,689	166	3,953	2%
9-Foreign Interference	7,278	565	4,104	21,343	7,851	41,141	25%
Total	13,741	17,746	25,389	41,150	63,448	161,474	100%

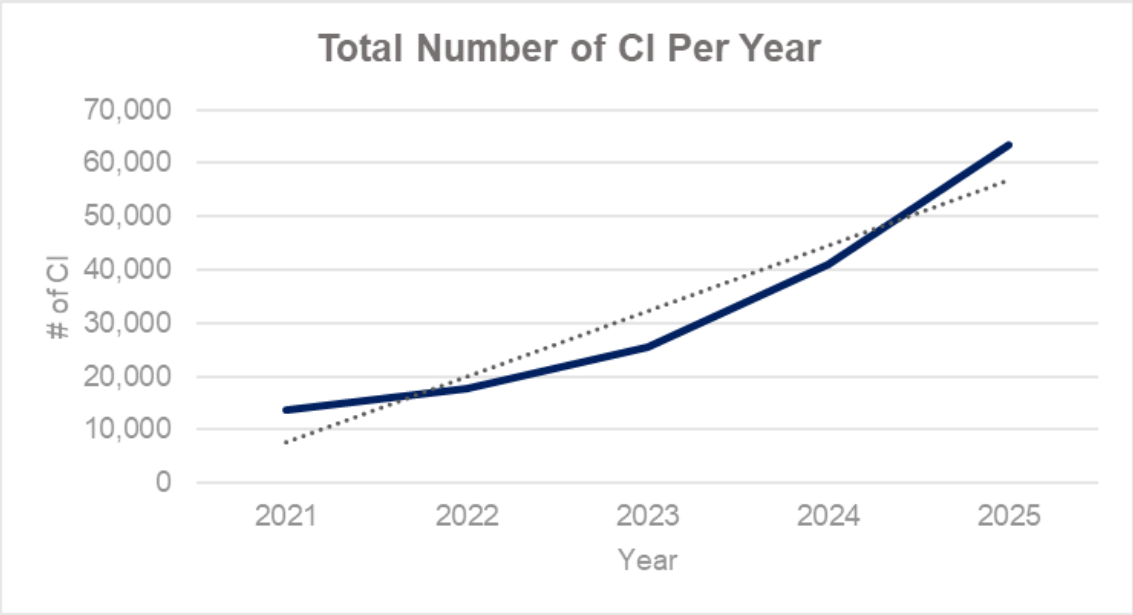

Figure 5.2-9: Total Number of CI per Year

Table 5.2-12: Customer Hours Interrupted Numbers (rounded) by Cause Codes – Excluding MEDs

Cause Code	2021	2022	2023	2024	2025	Total CHI	%
0-Unknown/Other	296	2,119	2,899	3,122	7,020	15,457	8%
1-Scheduled Outage	759	748	3,008	4,884	6,816	16,214	9%
2-Loss of Supply	0	0	11,612	1,628	10,237	23,476	13%
3-Tree Contacts	1,090	2,757	2,183	1,871	8,621	16,522	9%
4-Lightning	4	9	2	0	0	15	0%
5-Defective Equipment	9,347	902	3,837	6,577	9,543	30,206	16%
6-Adverse Weather	6,085	11,166	7,001	5,298	686	30,236	16%
7-Adverse Environment	0	0	0	34	7	40	0%
8-Human Element	60	1,912	0	2,475	787	5,234	3%
9-Foreign Interference	17,304	1,566	9,143	12,955	6,858	47,826	26%
Total	34,945	21,179	39,684	38,843	50,575	185,226	100%

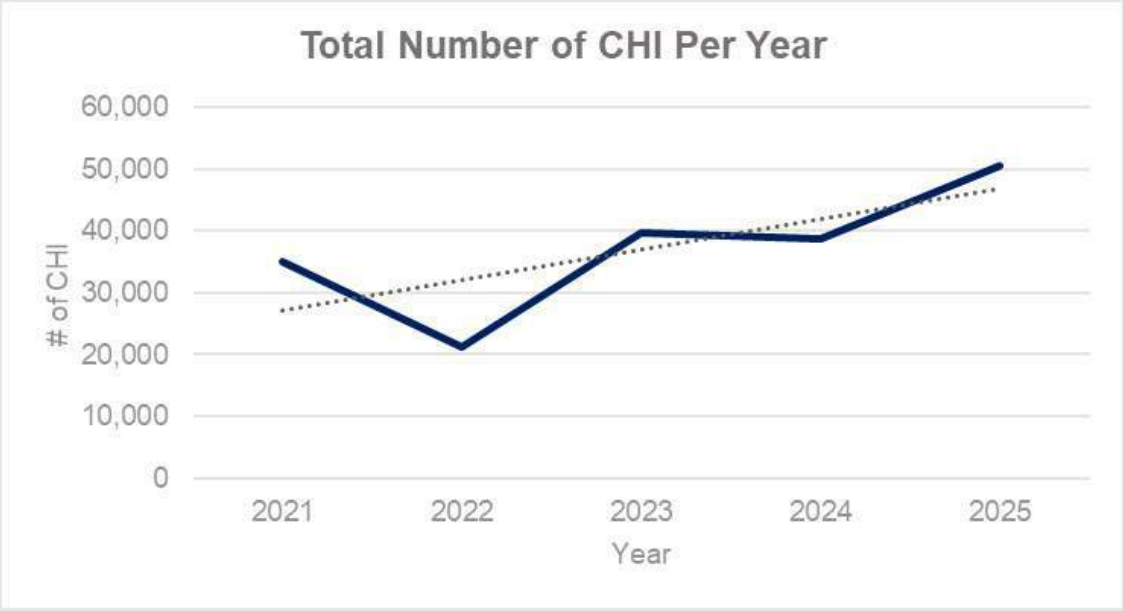

Figure 5.2-10: Total Number of CHI per Year

The trend for total number of CI and total number of CHI over the historical period are increasing. The increasing CI observed over the historical period is largely driven by Foreign Interference and Adverse Weather. Meanwhile, the increase in CHI observed in 2023 can be largely attributed to Loss of Supply and Foreign Interference.

When analyzing CI and CHI, Adverse Weather, Foreign Interference, and Loss of Supply are among the top cause codes for both CI and CHI. However, Unknown/Other is another major contributor for CI and Defective Equipment 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).
- 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).

5.3 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

The distributor must provide an overview of its planning process[1] 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:

- Ensuring public and worker safety;
- Meeting legislative requirements;
- Mitigating environmental risk;
- Maintaining system reliability;
- Managing costs; and
- 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

[1] This includes a distributor's capital expenditure planning process.

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.

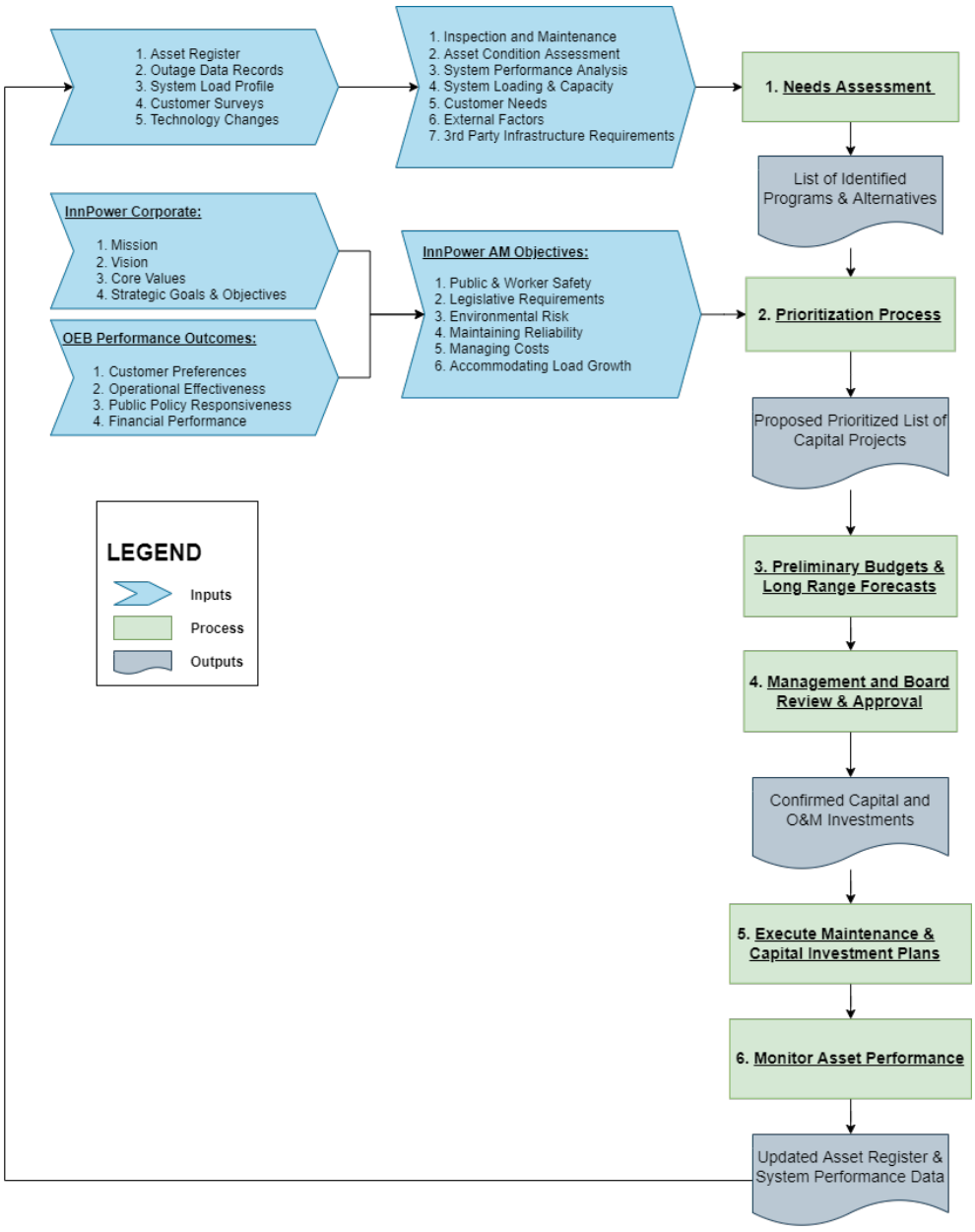

Figure 5.3-1: InnPower Asset Management Process

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 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 filing the previous DSP in 2023, InnPower has continued to refine and enhance its AM practices while maintaining consistency in its overall AM methodology and corporate approach. The same core

team continues to support and execute the AM process, providing continuity in expertise, application, and decision-making.

Enhancements during this period have focused primarily on improving the efficiency, accessibility, completeness, and quality of asset-related data management. InnPower has increased its collection of asset condition, inspection, and testing data to support asset assessments and ongoing AM decision-making. InnPower has also incorporated the use of Senpilot AI to support the collection, organization, and review of asset-related information. While this tool improves data accessibility and enables more efficient analysis, it does not replace or alter the established analytical frameworks, methodologies, or decision-making principles that continue to guide InnPower's AM process.

The increased data collection, inspection, and testing activities require additional effort to support asset information gathering and analysis; however, they have not resulted in material changes to the established AM methodology or asset replacement approach. These ongoing improvements support more timely and informed asset management decisions while maintaining consistency with the established approach used in previous DSP and ACA filings.

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 is 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-distribution alternatives, cost-effective implementation of distribution improvements affecting reliability and meeting customer needs at acceptable costs to customers, other innovative technologies.

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 provided 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 [2] ."

On June 12, 2025, the OEB received a directive regarding the implementation of the Government of Ontario's Integrated Energy Plan (IEP)[3].19 Pursuant to that directive, and specifically in relation to item 2 (2.1 and 2.2):

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[2] Load Forecast Guideline for Ontario, p. 17

[3] Directive regarding the implementation of the Government of Ontario's Integrated Energy Plan - Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7, June 12, 2025, p.5

- *A distributor should describe how its planning processes have been impacted by its multiple demand load forecasts, as described in Exhibit 3 of the Chapter 2 Filing Requirements for Electricity Distribution Cost of Service Rate Applications. This should include qualitative and quantitative risk and uncertainty assessments, as appropriate, for each demand load forecast.*
- *A distributor should incorporate cost projections for future investments that reflect reasonable assumptions for cost trends.*
- *A distributor should consider frequent and extreme weather impacts on energy infrastructure resilience and ensure future average, minimum and maximum temperatures are considered (this can be considered in the load forecast described in Chapter 2 Filing Requirements Section 2.3.1.3).*
- *Where a system investment, policy, or program is intended to facilitate fuel switching, the distributor should consider costs and benefits across impacted energy systems.*

Distributors should begin incorporating these requirements into their applications on a best-efforts basis by June 30, 2026. Distributors must address the requirements in applications filed after April 1, 2027 (expected for rates effective January 1, 2028 or later).

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:

1. 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.
2. 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.
3. 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.
4. 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. Broader considerations, including economic growth, are also considered as part of InnPower's overall planning and investment decision-making process, where applicable. 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. Given that System Access projects are typically driven by customer requirements and growth needs, economic growth considerations are inherently reflected in the identification and development of these projects.

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. Once projects are identified, InnPower also considers additional opportunities during project development and scope definition, including economic growth considerations, alignment with the OEB's 200A mandate, and storm hardening opportunities where applicable. To increase the objectivity of its project prioritization process, InnPower assigns weights to its AM objectives, as depicted in Figure 5.3-2.

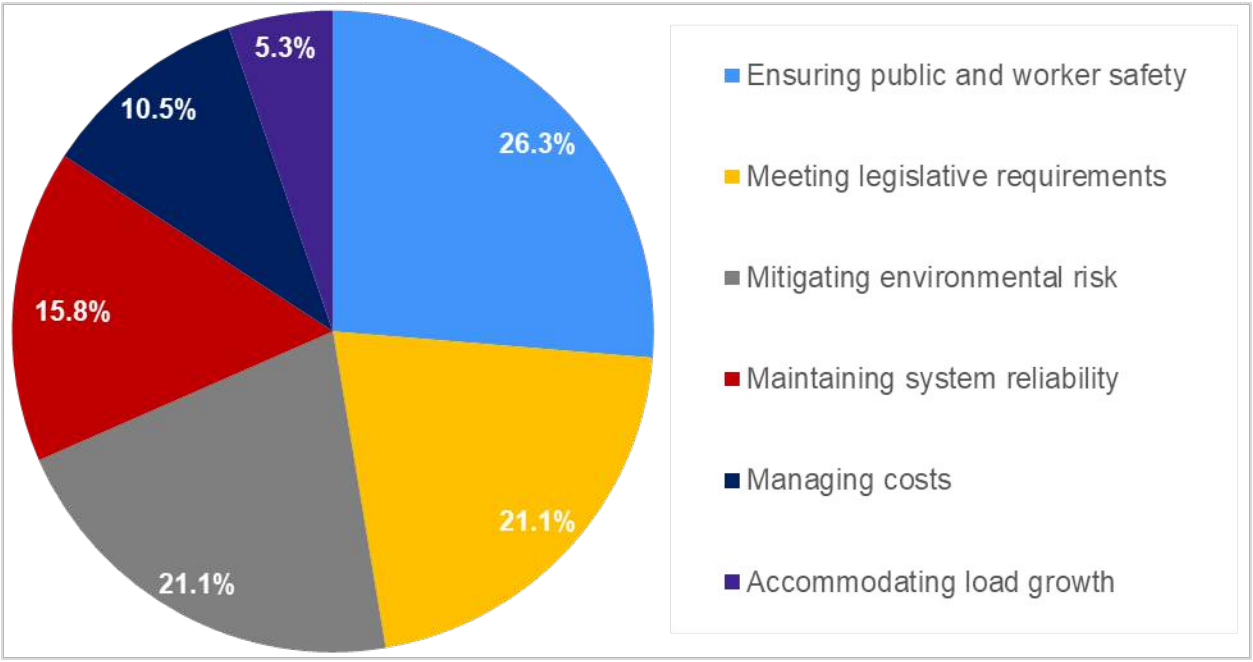

Figure 5.3-2: Weighted Priorities for Asset Management and Capital Expenditure Planning

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 2027 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 2027 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, and pace the execution of investments over the term of the DSP (e.g., asset condition by major asset type and reliability information).

<<Note: This should include reference to the LDC's mission, vision, values and corporate strategic goals.>>

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
Spreadsheets	Engineering	> Reclosers > Padmounted switchgear > Pole database > Transformer information > SCADA-Mate switches > 44 kV switches	Electronic data
NorthStar database	Operations	> Transformer data	Electronic data

Asset Database			
Component	**Owner/Location**	**Asset Information**	**Data Format**
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 May 2026 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 D.

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 Appendices B, C, and D.

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

The assessment of a DSP 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 its 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 for 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. Due to the proximity of Lake Simcoe, the area is also characterized by a generally high-water table. 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 70.4% of InnPower's primary conductors are OH and the remaining 29.6% 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 at an average annual rate of approximately 5.4%. 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: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2021	18,415	1,210	78	19,703
2022	19,170	1,263	80	20,513
2023	20,977	1,273	86	22,336
2024	22,124	1,298	83	23,505
2025	22,951	1,301	94	24,346

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 2027 – 2031 Business Plan attached as Appendix 1-7 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 approximately 2.2% annually over the forecast period, and by the year 2031, InnPower expects its customer base to be approximately 14% 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.

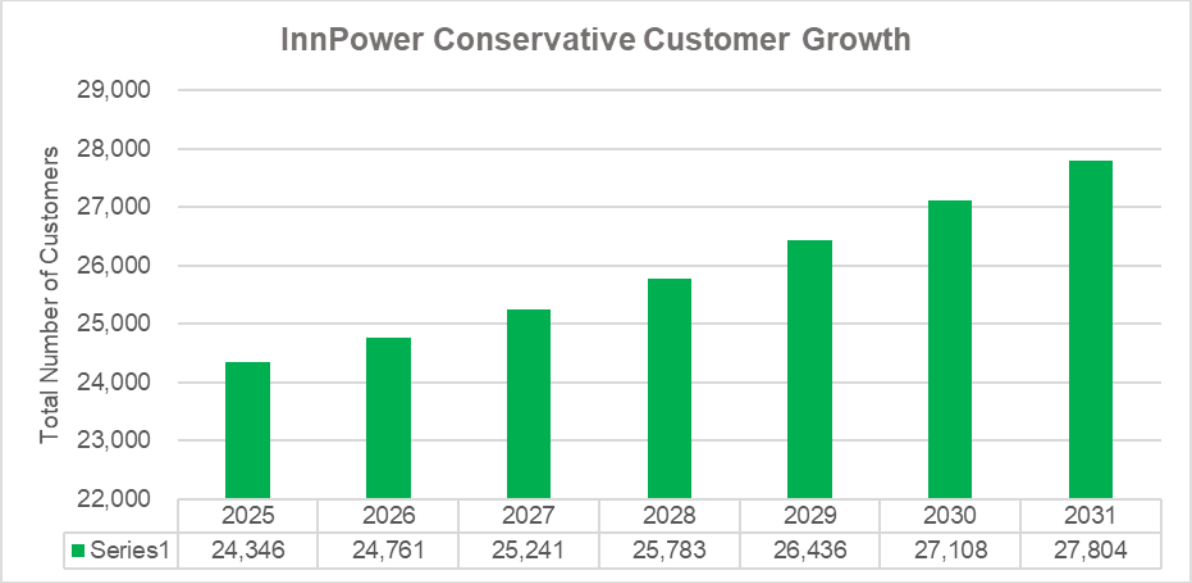

Figure 5.3-3: InnPower Conservative Projected Customer Growth[4]

Under the optimistic (non-conservation) growth projection, InnPower is expecting its customer base to grow by an average of over 4.4% annually over the forecast period, as shown in Figure 5.3-4. By the year 2031, InnPower expects its customer base to be over 30% higher relative to its current customer base.

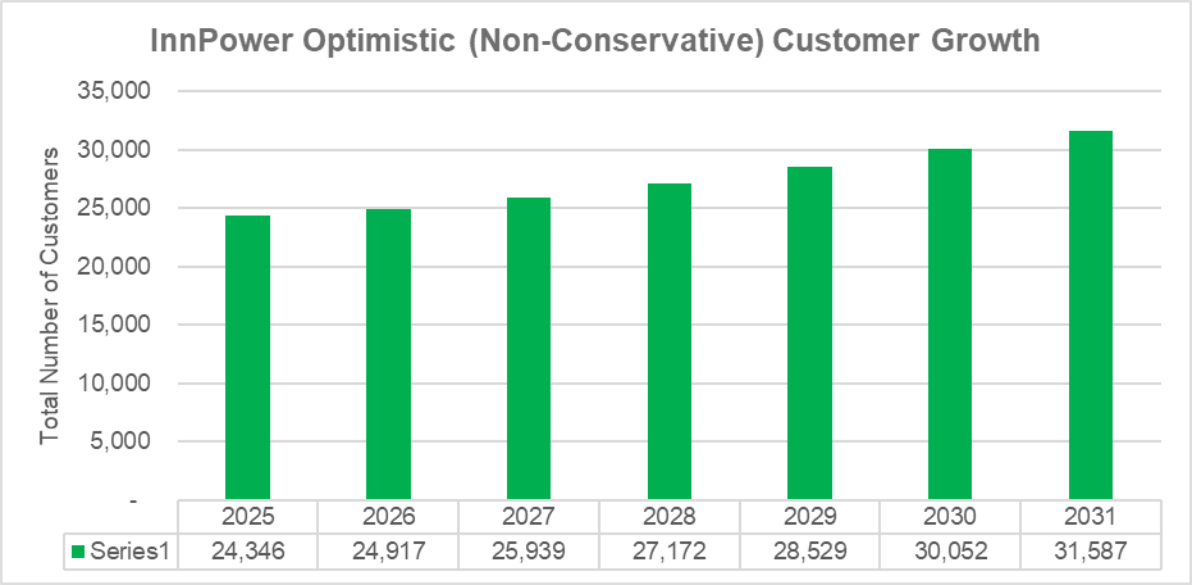

Figure 5.3-4: InnPower Optimistic Projected Customer Growth

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: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2021	52,272	62,170	57,221
2022	56,530	63,546	60,038
2023	53,240	64,660	58,950
2024	58,021	71,721	64,871
2025	60,290	79,260	69,775

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.

Table 5.3-5 indicates the efficiency of the kilowatt-hour purchased by InnPower and delivered. Historically, losses as a percentage of purchased energy have exceeded 5%, with notable improvement observed in 2025, where losses declined to 5.08%. InnPower continues to monitor system losses and has undertaken analysis to better understand the contributing factors associated with elevated losses. These insights support the identification and implementation of measures to minimize losses and improve overall system efficiency moving forward.

Table 5.3-5: Efficiency of kWh Purchased by InnPower

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2021	278,373,132	295,240,254	5.7%
2022	283,532,336	299,934,504	5.5%
2023	285,924,693	303,103,175	5.7%
2024	308,438,102	324,696,010	5.0%
2025	332,174,438	349,049,038	5.0%

5.3.2.1.4 Summary of System Configuration

As of June 2026, InnPower owns 931 km of primary conductors, of which 656 km is OH primary conductor and 275 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	94.36	351.23	445.59
27.6/16.0 kV	179.65	158.11	337.76
44 kV	1.25	146.43	147.68
Total	**275.26**	**655.77**	**931.03**

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 DSs 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).

InnPower is supplied from four TS cumulatively rated for 210.5 MVA. Table 5.3-8 lists the rated nominal capacity of each TS, in MVA.

Table 5.3-8: Rated Capacity of Transformer Stations

Substation	Output Voltage (kV)	Nominal Capacity (MVA)
Alliston TS	44	56.5
Barrie TS	44	50
Everett TS	44	4
Proposed New TS*	27.6	100
Total Nominal Capacity (MVA)		**210.5**

* Proposed New TS is a planned transformer station and is not currently in service. The listed capacity reflects the anticipated future capacity upon commissioning.

5.3.2.1.5 Climate

The Town of Innisfil and the Barrie region experience a humid climate heavily influenced by Lake Simcoe, resulting in four distinct seasons, with about 4 months of warm summer weather and 3 of snowy, cold winter weather.[5] Compared to many areas of southern Ontario, the region experiences greater winter snowfall due to lake effect weather systems associated with the Georgian Bay snowbelt, while the proximity to Lake Simcoe can moderate some temperature extremes near the shoreline.[6]

Summer temperatures range from the mid-teens to mid-20s Celsius, although periods of humidity can push temperatures above 30 Celsius, and cause mugginess. Winters are snowy and cold, with temperatures frequently below freezing, severe winter storms – heavy snow, strong wind and freezing rain.

Innisfil and Barrie experience significant seasonal variability, including frequent winter storms and rapidly changing weather conditions. However, due to the frequency of freezing temperatures in winter, snow cover often remains on the ground for extended periods.

Precipitation is relatively evenly distributed throughout the year and includes rainfall, snowfall, freezing rain, and severe thunderstorms depending on the season. The region is particularly susceptible to lake effect snow squalls, strong winter winds, and freezing precipitation events due to the influence of Lake Simcoe and Georgian Bay. Heavy snowfall and prolonged snow events are common during winter months, while spring and summer seasons can bring intense rainfall, localized flooding, and severe thunderstorms. The City of Barrie identifies severe winter storms, flooding, tornadoes, freezing rain, and extreme heat as key natural hazards affecting the region. Barrie has also experienced several significant tornado events, demonstrating the area's vulnerability to extreme summer weather.[7]

Extreme weather events can have significant impacts to overhead electrical infrastructure through ice loading, debris related faults, falling tree limbs, and pole or cross arm failures. Lake effect snow squalls

[5] https://weatherspark.com/y/19882/Average-Weather-in-Innisfil-Ontario-Canada-Year-Round
[6] https://horseshoeresort.com/2020/01/ontario-snowbelts/
[7] https://www.barrie.ca/government-news/emergency-management/hazards-risk-assessment

and strong winds can also contribute to widespread outages and extended restoration times. Severe summer thunderstorms and tornadoes may cause widespread wind damage, flooding, debris related faults and vegetation contact with electrical infrastructure, increasing outage frequency and restoration complexity. Additionally, prolonged heat events place additional stress on the electricity distribution system by increasing peak electricity demand for cooling during summer months.

5.3.2.1.6 Economic Growth

The Town of Innisfil and Barrie region are expected to grow rapidly over the next 25-years, supported by strong population growth, continued residential and commercial development, infrastructure investment, and its strategic location within the Greater Golden Horseshoe.[8] Growth in the region continues to be driven by migration from the Greater Toronto Area, improved transportation connectivity, and increasing demand for housing, logistics, healthcare, and commercial services. Barrie has consistently ranked among Canada's fastest growing mid-sized municipalities, while Innisfil continues to experience significant residential expansion and employment land development along the Highway 400 corridor.

Key drivers of growth include:

Residential and population growth: Barrie and Innisfil continue to experience substantial residential construction activity fueled by population migration from the Greater Toronto Area and broader provincial housing demand. The Province of Ontario has established aggressive housing targets for both municipalities, with Barrie expected to accommodate significant intensification and greenfield development over the coming decades. Innisfil's growth strategy includes major residential communities and mixed-use developments designed to support long-term population and employment growth.

Employment lands and industrial development: The Highway 400 corridor continues to attract industrial, logistics, warehousing, and commercial investment due to the region's strategic access to the Greater Toronto Area and northern Ontario markets. Barrie's industrial parks and Innisfil's employment lands near Highway 400 are expected to support continued growth in transportation, manufacturing, and distribution related sectors. Innisfil has also identified economic development opportunities tied to innovation, technology, and advanced manufacturing as part of its long-term growth planning.[9]

Infrastructure and institutional investment: Ongoing investment in roads, transit, water and wastewater infrastructure, healthcare, and municipal services is expected to support continued regional growth.[10]

It should be noted that while the Town of Innisfil and Barrie region is experiencing significant growth, portions of the local electricity distribution service territory remain primarily residential in nature, with modest small to medium sized commercial and industrial customers. As a result, broader regional growth may not directly translate into significant industrial electricity demand within all areas of the service territory.

The region also faces challenges related to housing affordability, labour shortages, infrastructure capacity, and an aging population. Continued immigration, workforce attraction, and infrastructure investment will be important to sustaining long-term growth and supporting future development.

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[8] https://www.getinvolvedinnisfil.ca/growth

[9] https://www.innisfil.ca/government-administration/plans-reports-strategies/economic-development-strategic-plan

[10] https://www.barrie.ca/planning-building-infrastructure/infrastructure/infrastructure-projects

Economic uncertainty related to interest rates, inflation, construction costs, and broader economic conditions may affect the pace of development during the planning period. However, strong population forecasts and continued infrastructure investment are expected to support ongoing long-term growth across the Barrie and Innisfil region.

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 & 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 load growth in the Innisfil and south Barrie areas, a new transformer station (InnPower's first TS) is planned to be energized toward the end of the forecast period, currently anticipated in 2030, though potentially later, as load behaviour is being actively monitored and the project will be deferred as long as practicable. The following analysis assumes an energization date of 2030. The station will consist of two 230/27.6 kV, 50/67/83 MVA transformers and eight outgoing feeders shown in Table 5.3-9 and Table 5.3-10.

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

Transformer	Nominal MVA	Peak Load (MVA)											
		2026		2027		2028		2029		2030		2031	
		S	W	S	W	S	W	S	W	S	W	S	W
New TS T1	50/67/83	---	---	---	---	---	---	---	---	13.82	11.74	23.18	21.60
New TS T2	50/67/83	---	---	---	---	---	---	---	---	4.10	3.49	5.01	4.30

Table 5.3-10: Transformer Station 230/27.6 kV Feeders – Summer & Winter Peak Load Forecast

Feeder	Recloser Setting (A)	Peak Load (A)											
		2026		2027		2028		2029		2030		2031	
		S	W	S	W	S	W	S	W	S	W	S	W
New TS T1 F1	400	---	---	---	---	---	---	---	---	61.81	52.54	99.60	85.46
New TS T1 F3	400	---	---	---	---	---	---	---	---	101.67	86.42	184.75	158.51
New TS T1 F5	400	---	---	---	---	---	---	---	---	72.37	61.51	153.87	132.02
New TS T1 F7	400	---	---	---	---	---	---	---	---	53.17	45.20	88.54	75.97
New TS T2 F2	400	---	---	---	---	---	---	---	---	14.12	12.00	27.61	23.69
New TS T2 F4	400	---	---	---	---	---	---	---	---	---	---	---	---
New TS T2 F6	400	---	---	---	---	---	---	---	---	5.50	4.68	5.50	4.72
New TS T2 F8	400	---	---	---	---	---	---	---	---	66.21	56.28	71.61	61.44

44 kV System Utilization

There are five 44 kV feeders within the InnPower's service territory. Another 44 kV feeder is planned to be added by 2026 bringing the total to six. Nominally, 44kV feeders on InnPower's system are rated for 330 A, but the assigned capacity from Hydro One differs and listed in the Table 5.3-11.

Table 5.3-11 illustrates the summer and winter peak load forecasts for each 44kV feeder for the years 2026 to 2031. Feeders exceeding 80% of their assigned capacity are highlighted in yellow.

Table 5.3-11: 44 kV Feeder Summer and Winter Peak Load Forecast

44 kV Feeder	Feeder Assigned Capacity (A)	Peak Load (A)											
		2026		2027		2028		2029		2030		2031	
		S	W	S	W	S	W	S	W	S	W	S	W
Alliston 9M1 & 9M2*	523	481.5	398.7	499.6	417.7	524.9	443.0	553.6	471.6	576.6	495.9	593.0	514.7
Alliston 9M4	223	206.6	171.1	214.2	179.0	225.5	190.3	239.0	203.7	249.1	214.2	257.9	223.8
Everett 9M6	105	60.1	48.0	75.9	61.2	90.6	73.8	91.4	75.1	93.0	77.2	94.4	79.1
Barrie 515M3 & 515M8**	660	410.2	331.5	464.9	379.3	536.1	441.7	620.5	516.3	527.6	443.2	515.3	437.0

*Two feeders from the same bus at the transformer station

**Feeders are currently jumpered together 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, 9M2, and 9M4 are being monitored through Hydro One and also InnPower to possibly transfer any future loads to the new Barrie 515M3 and 515M8 feeders as well as InnPower's new TS.
- InnPower is planning to utilize the maximum nominal feeder ratings on 515M3 and 515M8. The new TS will be an alternative to transfer additional loads beyond 2030.

Distribution Station Transformer Utilization

Table 5.3-12 presents the summer and winter peak load forecast for each DS for the years 2026 to 2031. DESN station transformers are assessed independently. Transformers exceeding 80% of their nominal load are highlighted in yellow and those exceeding 100% of their nominal load are highlighted in red.

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

Transformer	Nominal MVA	Peak Load (MVA)											
		2026		2027		2028		2029		2030		2031	
		S	W	S	W	S	W	S	W	S	W	S	W
Belle Ewart T1[1]	10/13.3/16.6	10.13	8.39	10.90	9.11	12.00	10.13	13.17	11.22	13.60	11.70	13.90	12.07
Belle Ewart T2[2]	30	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.51	1.82	1.53	3.53	2.99
Big Bay Point T1	10/12/16	3.99	3.22	4.05	3.30	4.57	3.77	5.31	4.42	5.32	4.47	5.33	4.52
Big Bay Point T2	16/20/24	5.75	4.64	5.98	4.88	6.98	5.75	9.21	7.66	5.50	4.62	5.00	4.24
Bob Deugo T1	10	4.64	3.75	5.22	4.26	5.85	4.82	6.14	5.11	6.20	5.21	6.24	5.29

Transformer	Nominal MVA	Peak Load (MVA)											
		2026		2027		2028		2029		2030		2031	
		S	W	S	W	S	W	S	W	S	W	S	W
Bob Deugo T2[3]	20/25/30	2.98	2.41	4.26	3.48	6.50	5.36	8.50	7.07	5.00	4.20	4.80	4.07
Brian Wilson T1	10	7.11	5.89	7.35	6.15	7.60	6.41	7.72	6.57	7.79	6.70	7.87	6.83
Brian Wilson T2[4]	10/13.3/16.6	12.73	10.54	14.51	12.13	15.99	13.50	17.18	14.64	17.75	15.27	18.22	15.82
Cedar Point T1	5	4.55	3.77	4.62	3.86	4.64	3.92	4.69	3.99	4.73	4.07	4.78	4.15
Cedar Point T2	7.5/10/12.5	1.35	1.12	1.40	1.17	1.42	1.20	1.51	1.29	1.53	1.31	1.54	1.34
CooksTown West	7	4.02	3.21	4.10	3.31	4.17	3.39	4.19	3.44	4.23	3.51	4.27	3.58
Innisfil	7.5/9.9/12.5	5.80	4.80	5.82	4.87	5.84	4.93	5.87	5.00	5.87	5.05	5.93	5.15
Lefroy	5	3.23	2.67	3.25	2.72	3.26	2.75	3.42	2.92	3.59	3.08	3.74	3.24
Leonard's Beach	7.5/10/12.5	5.89	4.76	5.95	4.85	6.01	4.95	6.07	5.05	6.08	5.11	6.09	5.16
Sandy Cove T1	5	00	2.42	3.03	2.47	3.06	2.52	3.10	2.58	3.11	2.61	3.12	2.65
Sandy Cove T2	5	0.92	0.74	1.18	0.96	1.32	1.09	42	1.18	1.43	1.20	1.44	1.22
Stroud	5	2.49	2.01	2.51	2.05	2.54	2.09	2.58	2.15	2.59	2.18	2.60	2.20
Thornton	5	2.22	1.84	2.24	1.87	2.26	1.91	2.27	1.93	2.29	1.97	2.32	2.01

[1] There is currently an ongoing (100% recoverable) project with a group of developers to upgrade this transformer to 16/20/24 MVA in order to accommodate projected load growth in the area.

[2] This transformer relates to a forecasted project that has not yet been built. Energization is planned for 2029, contingent upon execution of an agreement with the beneficiary developers (100% recoverable).

[3] The transformer has arrived on site and is scheduled to be energized in 2026.

[4] A larger transformer (20/25/30 MVA) has arrived on site and is scheduled to be energized in 2026.

Distribution Feeder Utilization

Table 5.3-13 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 5.3-13: Distribution Feeder Summer and Winter Peak Load Forecast

Feeder[1]	Recloser Setting (A)	Peak Load (A)											
		2026		2027		2028		2029		2030		2031	
		S	W	S	W	S	W	S	W	S	W	S	W
BEF1	350	51.85	42.93	60.01	50.17	74.43	62.81	92.60	78.90	100.02	86.01	104.41	90.63
BEF2	350	160.06	132.53	168.01	140.46	176.60	149.05	182.90	155.83	184.48	158.66	186.37	161.77
BEF3	350	-	-	-	-	-	-	5.10	4.25	15.23	12.79	29.54	25.05
BEF4	350	-	-	-	-	-	-	7.66	6.37	22.84	19.19	44.31	37.57
BBPF1	350	42.01	33.94	42.23	34.46	49.94	41.15	62.26	51.80	62.39	52.41	62.53	53.02
BBPF2	350	41.38	33.43	42.49	34.67	45.66	37.62	48.82	40.62	48.90	41.07	48.97	41.53
BBPF3	350	117.32	94.80	119.24	97.30	124.81	102.84	138.08	114.88	92.04	77.32	83.68	70.96

Feeder[1]	Recloser Setting (A)	Peak Load (A)											
		2026		2027		2028		2029		2030		2031	
		S	W	S	W	S	W	S	W	S	W	S	W
BBPF4	350	2.90	2.34	5.79	4.72	21.21	17.47	54.59	45.42	23.01	19.33	20.92	17.74
BDF1	350	42.95	34.70	54.22	44.24	60.81	50.11	63.84	53.12	64.47	54.15	64.89	55.02
BDF2	350	54.12	43.73	54.98	44.86	61.57	50.73	64.60	53.75	65.23	54.79	65.65	55.67
BDF3	350	54.14	43.74	65.37	53.34	86.51	71.28	111.08	92.42	72.10	60.56	69.59	59.01
BDF4	350	8.20	6.63	23.75	19.38	49.47	40.76	66.74	55.52	32.50	27.30	30.82	26.14
BWF1	400	125.16	103.64	128.32	107.28	131.48	110.97	132.99	113.30	134.12	115.34	135.26	117.40
BWF2	400	23.64	19.57	25.52	21.34	27.40	23.13	28.41	24.20	28.89	24.85	29.38	25.50
BWF3	350	177.91	147.31	212.77	177.87	241.18	203.56	256.11	218.20	263.25	226.40	269.20	233.67
BWF4	350	88.39	73.18	90.84	75.94	93.36	78.80	103.32	88.03	108.08	92.95	112.05	97.26
CPF1	280	155.45	128.71	157.87	131.98	158.57	133.83	160.18	136.47	161.80	139.15	163.45	141.87
CPF2	340	160.30	132.73	162.73	136.04	163.43	137.93	165.04	140.61	166.66	143.33	168.30	146.09
CPF3	440	93.68	77.57	97.15	81.22	98.54	83.17	104.79	89.28	105.83	91.02	106.89	92.78
CWF2	280	143.30	114.35	145.76	117.49	147.66	120.19	148.24	121.86	149.46	124.05	150.70	126.28
CWF4	280	135.70	108.29	139.10	112.12	141.72	115.36	142.52	117.15	144.21	119.69	145.91	122.28
INNF1	340	134.02	110.97	134.49	112.43	134.88	113.83	135.66	115.58	135.66	116.67	137.04	118.95
INNF2	340	135.28	112.01	135.74	113.48	136.11	114.88	136.87	116.62	136.87	117.71	138.22	119.97
INNF3	340	133.20	110.29	133.65	111.74	134.03	113.12	134.79	114.84	134.79	115.92	136.14	118.17
LEF1	280	160.65	133.02	161.34	134.88	161.69	136.47	167.35	142.58	173.00	148.78	178.24	154.71
LEF2	280	-	-	-	-	-	-	-	-	-	-	-	-
LEF3	350	63.50	52.58	64.19	53.66	64.54	54.47	70.19	59.80	75.85	65.23	81.09	70.38
LBF1	280	73.56	59.44	74.79	61.02	76.02	62.64	77.27	64.29	77.51	65.11	77.72	65.91
LBF2	340	31.92	25.79	33.56	27.38	35.21	29.01	36.88	30.68	37.20	31.24	37.47	31.78
LBF3	400	303.26	245.03	304.48	248.46	305.72	251.91	306.97	255.40	307.21	258.06	307.42	260.69
SCF1	340	107.56	86.91	108.64	88.65	109.74	90.42	111.17	92.49	111.53	93.69	111.89	94.88
SCF2	340	63.92	51.65	81.73	66.69	91.78	75.63	98.48	81.94	99.47	83.55	99.93	84.74
SCF3	340	100.62	81.30	101.62	82.92	102.63	84.57	103.95	86.49	104.29	87.60	104.62	88.72
STF1	280	86.74	70.09	87.44	71.35	88.13	72.62	89.24	74.25	89.52	75.20	89.80	76.15
STF2	280	0.14	0.11	0.35	0.28	0.69	0.57	1.25	1.04	1.39	1.17	1.53	1.29
STF3	280	86.05	69.53	86.74	70.78	87.44	72.05	88.55	73.67	88.83	74.61	89.10	75.56
THF1	280	60.23	49.87	61.47	51.39	62.71	52.93	63.01	53.69	64.27	55.27	65.54	56.89
THF2	280	93.82	77.68	94.13	78.69	94.44	79.71	94.52	80.53	94.83	81.55	95.15	82.59

[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:

- A voltage conversion (8.32kV to 27.6kV) project has been defined and currently is in progress to transfer loads from LBF3 to BBPF2 to reduce LBF3 burden.
- Also, this load can be split between LB F2 and Sandy Cove F2 during emergency situations.
- Brian Wilson transformer is scheduled to be replaced with a higher capacity transformer to address the load growth.

5.3.2.2.2 Asset Condition and Demographics

The ACA study was prepared by InnPower to establish the health and condition of distribution and station assets in-service. The ACA is based on InnPower's asset data of February 2026.

Table 5.3-14 summarizes the numerical Health Index (HI) results for each asset classes assessed in the ACA. Figure 5.3-5 and Figure 5.3-6 present the graphical summary of the HI results of from the ACA for distribution assets and station assets, respectively.

Table 5.3-14: ACA Overall Results

Health Index Score							
Asset Class	**Count**	**Very Good**	**Good**	**Fair**	**Poor**	**Very Poor**	**No HI**
Distribution Assets							
Pole Mount Transformers	2,195	1,056	885	175	79	0	0
Pad Mount Transformers	2,161	1,754	387	15	4	1	0
Pad Mount Switchgear	121	59	54	7	1	0	0
Overhead Loadbreak Switches	51	32	0	19	0	0	0
Overhead Disconnect Switches	493	492	1	0	0	0	0
Overhead Line Reclosers	31	3	5	1	22	0	0
Capacitors	9	9	0	0	0	0	0
Regulators	3	3	0	0	0	0	0
Wood Poles	11,008	2,538	3,463	3,058	1,817	132	0
Underground Cables (Age)	~275 km	n/a	n/a	n/a	n/a	n/a	n/a
Overhead Conductors (Age)	~656 km	n/a	n/a	n/a	n/a	n/a	n/a
Station Assets							
Power Transformers	14	7	6	1	0	0	0
Power Transformer Tap Changers	14	6	6	2	0	0	0
Station Switches	21	13	6	0	0	2	0
Station Reclosers	31	25	6	0	0	0	0
Service Transformers	13	10	3	0	0	0	0
Lightning Arresters	26	21	1	1	1	0	2
Power Fuses	9	6	2	1	0	0	0
Ground Grids	10	7	0	0	0	3	0
Facilities	10	5	3	1	1	0	0

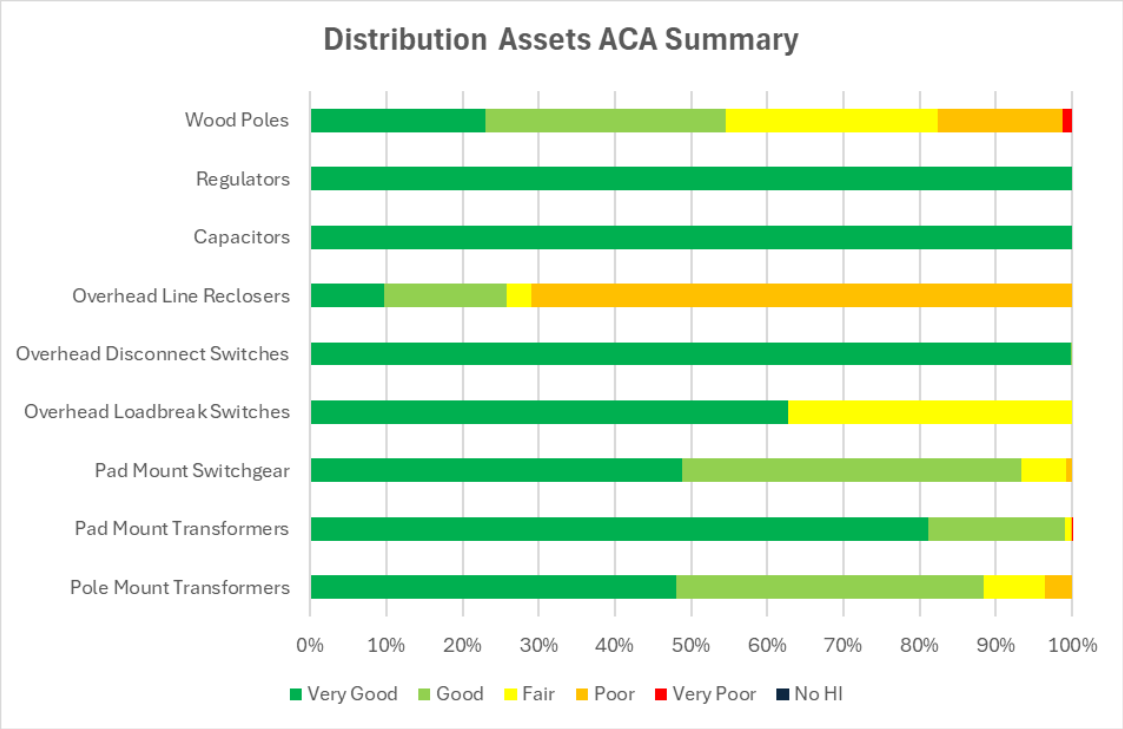

Figure 5.3-5: Distribution Assets ACA Summary

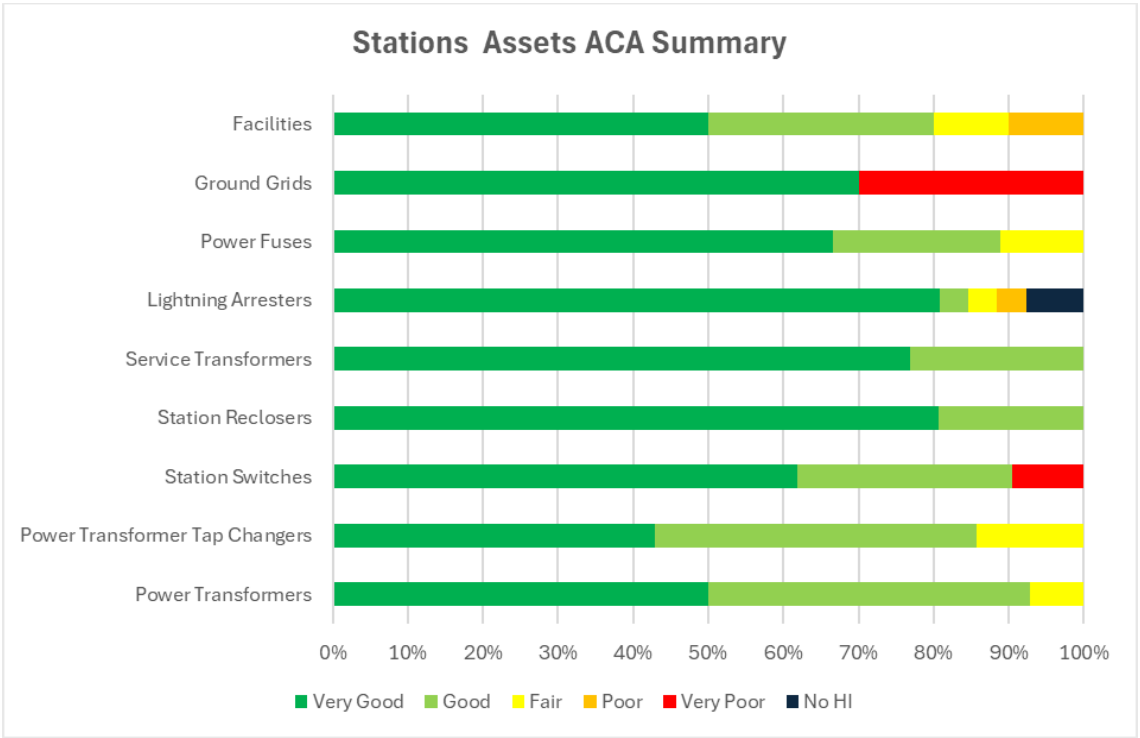

Figure 5.3-6: Station Assets ACA Summary

Figure 5.3-5 and Figure 5.3-6 indicate that the majority of InnPower's assets are generally in healthy condition. Some asset classes like Wood Poles, Overhead Line Reclosers, and Station Ground Grids have notable proportions of assets in Poor to Very Poor condition, indicating an increased probability of failure.

InnPower supplements its HI findings with a Data Availability Index (DAI): a measure of the availability of condition parameter data for a specific asset, weighted by each condition parameter's contribution to the HI score. For each assets a DAI threshold is used to measure whether there is sufficient data for a reliable HI calculation. The methodology is summarized in the complete ACA study can be found in Appendix D of the DSP.

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.

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 2021 to 2025 period is summarized in Table 5.3-15 and Figure 5.3-7.

Table 5.3-15: Defective Equipment Outages by Asset Type

Asset Type	Number of Annual Failures					Total	Percent of Total
	2021	2022	2023	2024	2025		
Arrestor	2	0	1	1	2	6	4.62%
Connection	1	3	7	3	2	16	12.31%
Cutout	2	0	0	0	2	4	3.08%
Fuse	1	4	0	3	3	11	8.46%
Fuse Link	0	0	2	1	3	6	4.62%
Insulator	0	1	1	0	1	3	2.31%
Linkets	0	0	3	1	2	6	4.62%
Meter	0	0	1	0	0	1	0.77%
Recloser	0	0	1	0	1	2	1.54%
Neutral	0	0	1	1	1	3	2.31%
Primary Conductor	0	0	2	3	0	5	3.85%
Secondary Conductor	1	5	0	2	1	9	6.92%
Sleeve	4	0	1	1	1	7	5.38%
Switch	0	1	3	0	4	8	6.15%
TX Insert	3	12	11	5	9	40	30.77%
TX Lead	0	0	0	0	1	1	0.77%
Transformers	0	0	0	0	1	1	0.77%
Unknowns	0	0	1	0	0	1	0.77%
Total	14	26	35	21	34	130	100.00%

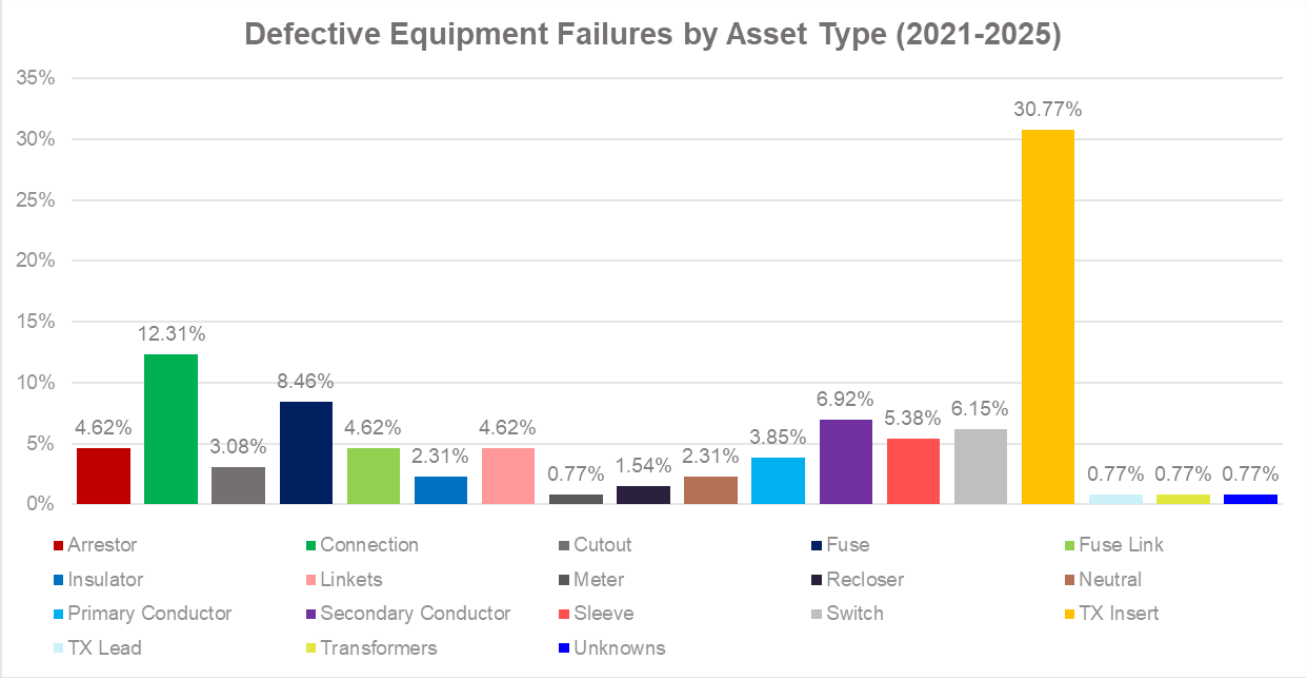

Figure 5.3-7: Defective Equipment Failures by Asset Type

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 that have previously been deemed by the OEB to be distribution assets During the forecast period, InnPower plans to develop a new 230 kV TS. InnPower is not seeking to have these assets deemed as distribution assets in this application and intends for the TS to be operated as a transmission asset.

5.3.2.4 Host & 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 Policies 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 Policy

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 investment is optimized and prioritized based on the ACA (see Appendix D). 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 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 system O&M activities to sustain an asset to the end of its service life (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 5.3-16.

Table 5.3-16: 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
Underground distribution assets	Padmount Transformers and switchgear	Visual inspection	Three-year cycle
Station assets	Distribution station	Visual inspection	Monthly

System	Asset	Practice	Schedule
	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
	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. Additionally, 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.
- Infrared and visual inspection results.

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 Padmount Switchgears 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 5.3-17 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 5.3-17: 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 5.3-18 presents the secondary criteria for vehicle assessment.

Table 5.3-18: 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. 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 & 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 InnPower using Senpilot AI 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 D, 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 Policies and Practices since Last DSP Filing

A distributor should provide a summary of any important changes to the distributor's asset life optimization policies and processes 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 enhanced its annual Preventative Maintenance Program through a comprehensive review of various asset classes. This work included the development and updating of applicable procedures, the establishment of appropriate inspection frequencies, and the allocation of the necessary resources to support inspection, replacement, maintenance, and record-keeping activities. The Preventative Maintenance Program is organized into the following primary sub-programs: vegetation management, overhead ("OH") inspection, overhead maintenance, underground ("UG") inspection, underground maintenance, and station inspection and maintenance.
- **Fleet Management Policy Updates:** InnPower recently updated its Fleet Management Policy and is currently developing a new Vehicle Replacement Procedure. These updates provide greater clarity and establish defined parameters for the maintenance, operation, and lifecycle management of fleet vehicles.

5.3.4 System Capability Assessment for REG & DERs

<<Note: If the distributor has no forecast costs to accommodate and connect REG facilities, state this and delete subsections 5.3.4(a) – 5.3.4 (e)>>

A distributor shall provide a list of restricted feeders by name, the feeder designation, the reason for the restriction, and number of connected customers, and explain if there are plans to improve its distribution system's ability to connect distributed energy resources.

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 of these filing requirements.

Pursuant to item 15 of the IEP Directive, and to continue the efforts to update distributed energy resources connections processes, where a distributor plans to improve the distribution system's ability to connect additional distributed energy resources in areas with restricted hosting capacity, the distributor must include in its application an assessment of potential solutions, including both infrastructure-based and non-infrastructure-based options.

This section is not applicable as InnPower has no planned investments or associated costs to accommodate or connect REG or DERs over the forecast period.

5.3.5 Non-Wires Solutions to Address System Needs

The Non-Wires Solutions Guidelines for Electricity Distributors (the NWS Guidelines)11 provide OEB guidance on the role of NWSs for rate-regulated electricity distributors and the treatment of NWSs in distribution rate applications. The NWS Guidelines require distributors to incorporate consideration of NWSs into their distribution system planning process by considering whether a distribution rate-funded NWS may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. NWSs potentially eligible for distribution rate funding are not limited to energy

[11] EB-2024-0118, March 28, 2024

efficiency programs and include activities that reduce instantaneous electricity demand, including demand response and energy storage12.

A distributor's DSP should describe how it has taken NWSs into consideration in its planning process. The degree of consideration of NWSs 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. NWSs will not be a viable alternative for all types of traditional infrastructure investments. Distributors are encouraged to take account of learnings from NWSs that have been undertaken by other electricity distributors, in Ontario or elsewhere.

Distributors are required to document their consideration of NWSs when making investment decisions on electricity system needs with an expected capital cost of $2 million or more, excluding general plant investments, making use of the Benefit-Cost Analysis Framework (BCA Framework). The requirements of the BCA Framework are detailed in Section 5.4.2.2.

Distributors may apply to the OEB for funding through distribution rates for NWSs as specified in the NWS Guidelines. 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 NWS (this could include investments upstream of a distributor), and the prioritization of the proposed NWS relative to other system investments in the DSP. A distributor should provide evidence as to why the proposed NWS is the preferred approach (alone or in combination with an infrastructure solution) to meeting a system need, including an assessment of the projected benefits to customers relative to cost impacts, following the requirements of the BCA Framework. Any proposal for a rate funded, distributor-owned NWS must demonstrate that a distributor has meaningfully explored contracting services from non-utility owned distributed energy resources – including providing sufficient lead time for third-party solutions to be identified and implemented – and doing so is either not feasible or less cost-effective.

InnPower considers NWS as part of its planning process (see section 5.3.1.3) to determine whether NWS can be considered a viable alternative to any of InnPower's planned investments over the forecast period. However, no viable NWS alternatives have been identified currently. As a result, there are no NWS activities currently planned over the forecast period.

Subdivision and Road Authority projects consist of multiple individual projects, with each individual project below the $2 million threshold requiring a standalone NWS assessment. Similarly, Station Rehabilitation investments comprise multiple smaller projects rather than a single discrete investment exceeding the threshold. Given the nature, scope, and operational requirements of these investments, NWS alternatives were determined to be non-feasible.

InnPower will continue to consider the ability to use distribution rate funded NWS to potentially defer or avoid investments.

5.3.6 Climate Vulnerability Assessment and System Hardening

The VASH policy is intended to complement distributors' existing planning processes. 22 Integrating resilience considerations into established processes will allow distributors to align resilience efforts with existing planning drivers such as asset renewal. This approach will help identify new options for dealing with end-of-life infrastructure while simultaneously creating additional value for customers by enhancing system resiliency.

[12] More examples are provided in the NWS Guidelines Section 2

The following requirements pertaining to VASH policy will apply on a best-efforts basis for applications filed for 2027 rates and will become mandatory for applications for 2028 rates.

A distributor is expected to perform Vulnerability Assessment (VA) using either the Generic Option or the Custom Option, as defined in the VASH policy. The assessment should identify parts of the distribution system (i.e., locations and asset classes) that are most vulnerable to extreme weather and other climate-related events. A distributor selecting the Generic Option is expected to upload, alongside the discussion of vulnerability assessment results in its DSP, a completed version of the Vulnerability Assessment Toolkit (VA Toolkit) that is available within the VASH Toolkit developed by the OEB. 23 A distributor using the Custom Option should ensure that the vulnerability assessment methodology it uses meets the criteria outlined in the VASH policy. It is also expected to file its custom vulnerability assessment study including the detailed calculations along with the discussion of results in its DSP. The assessment should be supported by clearly documented input data sources, rationale for asset and climate peril selection, and justification for any deviations from standard approaches.

After completing the VA, a distributor should conduct a pre-assessment to determine whether technically and economically feasible system hardening investments exist.

For example, as a part of the pre-assessment, distributors may:

- *Prioritize its analysis on the most significant vulnerabilities identified in the VA —those with the highest probability of failure or greatest potential impact on customers—while applying professional judgment and operational experience to focus effort where it is most likely to yield actionable solutions. Distributors must document their prioritization method and how the distributor has chosen to define significant vulnerabilities (e.g., top 10% of vulnerable locations or top 10 projects). This ensures the analysis is targeted and manageable, while still allowing flexibility to examine additional areas where warranted.*
- *Leverage historical data and operational experience to identify areas of the system that have experienced repeated or severe impacts from extreme weather events*
- *Assess the results of the VA in conjunction with other relevant information, such as asset condition assessments, historical performance, and alignment with other capital plans (e.g., system renewal or grid modernization).*
- *Consider geographic and environmental factors, such as vegetation density, terrain, or location that may influence the feasibility or urgency of hardening measures.*
- *Evaluate the technical feasibility of system hardening solutions to address the identified vulnerabilities, guided by a detailed understanding of the distribution system.*
- *Document the rationale for project selection or exclusion, including why certain vulnerabilities may not be addressed (e.g., no viable solution, cost-prohibitive).*

Regardless of whether the pre-assessment identifies economically plausible projects, a distributor is expected to document and explain its pre-assessment approach and submit it as part of its DSP. If a pre-assessment does not identify any economically plausible investments, the distributor does not need to conduct a benefit-cost analysis.

If the pre-assessment identifies economically plausible system hardening investments, a distributor must conduct a benefit-cost analysis for VASH for those investments and include the completed benefit-cost analysis for those projects in its application along with the pre-assessment results. Benefit-cost analyses are to be prepared for each specific system need and not applied generically across the

entire system. However, a single benefit-cost analysis may be used to support a program intended to address multiple, similar needs that may exist at different locations within the distribution system.

A distributor using the Generic Option is expected to use the Benefit-Cost Analysis Toolkit available within the VASH Toolkit to demonstrate that the proposed system hardening investments are beneficial and they provide value to its customers. A distributor choosing to pursue the Custom Option should ensure that the benefit-cost analysis methodology it uses meets the criteria outlined in the VASH policy.

Due to the timing of the new VASH guidelines, InnPower has been unable to complete the formal Vulnerability assessment using the OEB provided tool. InnPower endeavours to continue to work towards gathering all the information required to complete this tool in the future.

However, InnPower inherently considers vulnerability of the grid and its assets, as part of its asset management planning, and identifies key system hardening investments that can enhance the grids protection from extreme weather events and other vulnerabilities. When carrying out its normal renewal investments, InnPower ensures that any new assets installed, meet the latest industry standard, with standards and designs now typically accounting for system hardening. This is typical practice for its Pole, Distribution Transformer, Switch, Recloser and Switchgear renewal programs. Furthermore, InnPower invests in animal mitigation program, which helps protect the grid from any harm caused by animals, further hardening the grid.

InnPower is constantly evaluating the distribution system with every internal and customer driven project to improve resiliency. Grid hardening such as storm guying, smaller pole distances, stronger pole class, inspecting soil conditions, tree trimming practices and more automation are being implemented to address vulnerabilities in the grid and improve resilience.

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 operating and maintenance 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 above, a DSP must include information on the historical and forecast period.

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 the DSP's duration (including both a historical and forecast period) as outlined in section 5.2. 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, as 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:

Table 5.4-1: Historical Capital Expenditures and System O&M (in $'000)

Category	Historical														
	2022			2023			2024			2025			2026		
	Plan.[13]	Act.[14]	Var.	Plan.	Act.[15]	Var.	Plan.	Act.[16]	Var.	Plan.[17]	Act.	Var.	Plan.[18]	Bgt.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access															
Gross Capital Spend	29,867	11,647	-61%	25,385	18,148	-29%	23,410	19,869	-15%	17,381	27,172	56%	9,584	22,447	134%
Capital Contributions[19]	(26,234)	(3,900)	-85%	(23,890)	(11,516)	-52%	(21,160)	(9,740)	-54%	(15,179)	(17,158)	13%	(7,669)	(18,686)	144%
Net Capital Expenditures	3,633	7,747	113%	1,495	6,632	344%	2,250	10,129	350%	2,202	10,014	355%	1,915	3,760	96%
System Renewal															
Gross Capital Spend	13,334	6,895	-48%	1,544	3,589	132%	1,429	8,379	486%	1,593	5,484	244%	1,633	1,682	3%
Capital Contributions	(11,700)	(5,679)	-51%	0	(1,735)	-	0	(6,388)	-	0	(2,673)	-	0	(494)	-
Net Capital Expenditures	1,634	1,215	-26%	1,544	1,854	20%	1,429	1,991	39%	1,593	2,811	76%	1,633	1,189	-27%
System Service															
Gross Capital Spend	3,723	954	-74%	10,669	6,913	-35%	7,519	5,440	-28%	9,374	5,281	-44%	4,902	7,142	46%
Capital Contributions	(2,538)	0	-100%	(3,578)	0	-100%	(3,100)	(935)	-70%	(4,720)	0	-100%	0	(477)	-
Net Capital Expenditures	1,185	954	-20%	7,091	6,913	-3%	4,419	4,506	2%	4,654	5,281	13%	4,902	6,666	36%
General Plant															
Gross Capital Spend	761	1,020	34%	1,155	1,508	31%	1,022	969	-5%	730	850	16%	803	1,654	106%
Capital Contributions	0	0	-	0	0	-	0	0	-	0	0	-	0	(115)	-
Net Capital Expenditures	761	1,020	34%	1,155	1,508	31%	1,022	969	-5%	730	850	16%	803	1,539	92%
Total Expenditure, Gross	47,685	20,516	-57%	38,753	30,158	-22%	33,380	34,657	4%	29,078	38,787	33%	16,922	32,926	95%
Total Capital Contribution	(40,472)	(9,579)	-76%	(27,468)	(13,251)	-52%	(24,260)	(17,062)	-30%	(19,899)	(19,831)	0%	(7,669)	(19,772)	158%
Total Expenditure, Net	7,213	10,936	52%	11,285	16,907	50%	9,120	17,594	93%	9,179	18,955	107%	9,253	13,154	42%
System O&M	2163	2318	7%	2622	2734	4%	2,812	3,220	15%	3,000	3,459	15%	3,406	3,766	11%

[13] OEB-approved 2022 Plan amounts were not available in InnPower's previous CoS Application because the application was deferred by one year. Accordingly, the 2022 Plan values presented herein are based on internally completed planning prepared following the issuance of the 2024 Cost of Service Application.
[14] The 2022 Actual values differ from those presented in the previous application because the previous CoS application reported total ending WIP, whereas the values presented herein reflect the CWIP.
[15] The 2023 Actual values differ from those presented in InnPower's previous CoS Application because the previous application reported total ending WIP, whereas the values presented herein reflect the CWIP.
[16] The 2024 Actual values differ from those presented in InnPower's previous CoS Application because the previous application reported total ending WIP, whereas the values presented herein reflect CWIP. In addition, the 2024 financial results for Capital Contributions have been restated.
[17] The 2025 Plan values for System Service differ from those presented in InnPower's previous CoS Application because the TS project did not proceed as originally planned for those years.
[18] The 2026 Plan values for System Service differ from those presented in InnPower's previous CoS Application because the TS project did not proceed as originally planned for those years.
[19] Following 2024 rebasing, InnPower identified a correction to the methodology for forecasting System Access Capital Contributions, as described in Exhibit 1, Section 3, pages 26-27. The historical Plan and Actual values have been adjusted to reflect this correction. Accordingly, where both these values have been adjusted for a historical year, the resulting variance does not reflect the impact of the forecasting methodology issue. As described in Exhibit 1, InnPower corrected this methodology as part of its 2027 Cost of Service Application, with the corrected methodology applied beginning with the 2027 forecast and thereafter.

Table 5.4-2: Forecast Capital Expenditures and System O&M (in $'000)

Category	Forecast				
	2027	2028	2029	2030	2031
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital Spend	25,543	22,545	13,925	12,920	13,012
Capital Contributions	(18,332)	(11,326)	(5,361)	(4,178)	(4,233)
Net Capital Expenditures	7,211	11,219	8,564	8,742	8,779
System Renewal					
Gross Capital Spend	2,749	6,092	5,435	6,670	5,637
Capital Contributions	(469)	(481)	(494)	(519)	(533)
Net Capital Expenditures	2,281	5,610	4,941	6,151	5,104
System Service					
Gross Capital Spend	8,901	8,579	2,920	12,930	11,641
Capital Contributions	(390)	(3,581)	(419)	(424)	(279)
Net Capital Expenditures	8,511	4,998	2,502	12,507	11,362
General Plant					
Gross Capital Spend	3,878	3,398	1,412	1,936	2,271
Capital Contributions	(321)	(50)	(50)	(275)	(125)
Net Capital Expenditures	3,557	3,347	1,362	1,661	2,146
Total Expenditure, Gross	**41,071**	**40,613**	**23,692**	**34,456**	**32,560**
Total Capital Contribution	**(19,511)**	**(15,438)**	**(6,323)**	**(5,396)**	**(5,169)**
Total Expenditure, Net	**21,560**	**25,175**	**17,368**	**29,060**	**27,391**
System O&M	4,010	4,371	4,576	4,841	5,104

5.4.1.1 Plan vs Actual Variances for the Historical Period

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%, including that of actuals versus the OEB-approved amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP. 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.

5.4.1.1.1 2022 Variance Analysis

A planned-versus-actual variance analysis has not been provided for 2022, as the actual 2022 data was available at the time the previous DSP was filed. Accordingly, InnPower incorporated actual 2022 values in lieu of approved planned amounts in the DSP, resulting in no material variance between planned and actual results for that year.

5.4.1.1.2 2023 Variance Analysis

Table 5.4-3 below provides a summary of InnPower's 2023 capital expenditure variances by investment category, comparing approved plan values to the actual expenditures. Explanations are provided for material variances exceeding +/-10% of materiality threshold (i.e., $81,000), with a focus on key drivers.

Table 5.4-3: 2023 Budget Variance Explanations

Category	2023				Justification
	Plan.	Act.	Var.		
	$ '000		%		
System Access, Net	1,495	6,632	5,137	344%	System Access variances in 2023 were primarily driven by timing differences in customer- and developer-driven connection work, alongside the significant impact of energizing seven subdivisions, compared to one subdivision included in the approved plan, resulting in approximately 1,132 anticipated customer connections. While overall expenditures for Road Authority, customer-driven, and expansion projects remained roughly in line with proposed budgets, specific operational fluctuations shifted the final numbers. Layouts saw slightly higher spend due to a high volume of customer requests and the typical lag between receiving payments and completing jobs. Conversely, Road Authority expenditures trended slightly under budget due to external municipality delays. Because a significant portion of System Access expenditures is developer-funded, these variances inherently reflect the broader timing of development activity and capital contribution recoveries. Furthermore, the year's spending was shaped by the completion of deferred project backlogs from prior years, general fluctuations in

Category	2023				Justification
	Plan.	Act.	Var.		
	$ '000		%		
					development activity, and ongoing supply chain constraints that affected metering work and connection-related materials.
System Renewal, Net	1,544	1,854	310	20%	System Renewal variances in 2023 were driven by timing differences in lifecycle replacement programs, including pole, switch, and recloser work, with variances also reflecting the prioritization of asset condition-driven replacements, deferral of select programs, and completion of prior-year work. In particular, the pole replacement program was increased during the year to address some of the shortfall associated with lower-than-expected Road Authority expenditures. The availability of poles during a period of broader material constraints supported the decision to advance additional pole replacement work and optimize asset replacement activities.
System Service, Net	7,091	6,913	-178	-3%	System Service variances varied due to timing differences in station and line work, including delays in station rehabilitation activities, deferred line extension work, and sequencing of commissioning and system reinforcement projects such as the Barrie Area Transformer Upgrade program. In addition to timing differences between station and line work, commissioning activities were impacted by equipment issues identified during project execution, which delayed project progression until corrective actions were completed. In particular, an oil leak identified in one of the new power transformers at the station contributed to the schedule variance.
General Plant, Net	1,155	1,508	353	31%	General Plant variances were primarily driven by timing differences in IT and corporate capital investments, alongside cost fluctuations for routine fleet and

Category	2023				Justification
	Plan.	Act.	Var.		
	$ '000		%		
					equipment replacements. A significant underspend occurred within Finance IT due to the deferral of the new ERP. Conversely, these savings were offset by higher-than-budgeted expenditures in other areas. Specifically, IT Hardware experienced overages due to advanced server upgrades and critical physical asset replacements, while Engineering IT saw increased spend, likely driven by the GIS Utility Network Management (UNM) project. Additionally, fleet and equipment costs exceeded budget due to pandemic-related price increases for vehicles.
Total Expenditure, Net	11,285	16,907	5,622	50%	Net capital variances reflect aggregate variances across all capital categories, primarily driven by timing differences in capital program execution and development-related activity, partially offset by variability in capital contributions.
Capital Contributions[20]	-27,468	-13,251	14,217	-52%	Capital contribution variances in 2023 were primarily driven by timing and scope differences in connection activity, including shifting subdivision development schedules, the energization of seven new subdivisions, and the timing of associated recoveries. Because much of this work is developer-funded, variances reflect fluctuating customer layout requests, the lag between payment receipt and job completion, municipal delays, and the completion of prior-year backlogs. These contribution trends were further shaped by wider capital timing shifts across the business. This included the prioritization or deferral of lifecycle asset replacements in System Renewal,

[20] Following 2024 rebasing, InnPower identified a correction to the methodology for forecasting System Access Capital Contributions, as described in Exhibit 1, Section 3, pages 26–27. The historical Plan and Actual values have been adjusted to reflect this correction. Accordingly, where both values have been adjusted for a historical year, the resulting variance does not reflect the impact of the forecasting methodology issue. As described in Exhibit 1, InnPower corrected this methodology as part of its 2027 Cost of Service Application, with the corrected methodology applied beginning with the 2027 forecast and thereafter.

Category	2023				Justification
	Plan.	Act.	Var.		
	$ '000		%		
					alongside delays in station rehabilitations and line extensions within System Service. Additionally, General Plant experienced adjustments due to advanced IT hardware upgrades, the deferral of the new ERP system, and pandemic-related cost increases for fleet vehicles.
Total Expenditure, Gross	38,753	30,158	-8,595	-22%	Gross capital variances varied primarily due to timing differences in capital program execution across all categories, including deferral and advancement of selected projects and variability in development-driven work.
System O&M	2,622	2,734	112	4%	System O&M variances in 2023 were generally modest and were driven by fluctuations in planned and reactive maintenance activity, including customer-initiated locate requests, Distribution Inspection Requests (DIRs), and patrol-style trouble calls.

5.4.1.1.3 2024 Variance Analysis

Table 5.4-4 below provides a summary of InnPower's 2024 capital expenditure variances by investment category, comparing approved plan values to the actual expenditures. Explanations are provided for material variances exceeding +/-10% of materiality threshold (i.e., $81,000), with a focus on key drivers.

Table 5.4-4: 2024 Budget Variance Explanations

Category	2024				Justification
	Plan.	Act.	Var.		
	$ '000		%		
System Access, Net	2,250	10,129	7,879	350%	System Access variances in 2024 were driven by timing differences in customer- and developer-driven connection work, expansion and development activity, and capital contribution fluctuations. A major driver was the unexpected energization of 10 subdivisions compared to the planned one or two, resulting in 1,313 anticipated connections. Because these third-party projects are entirely dependent on housing market conditions, higher sales

Category	2024				Justification
	Plan.	Act.	Var.		
	$ '000		%		
					accelerated subdivision completions beyond expectations. These overages were partially offset by the deferral of a county-driven Road Authority project on Innisfil Beach Road from 10th Sideroad to Yonge Street, which shifted from 2024 to 2025 and created an underspend that helped fund higher spending in System Renewal. Ultimately, because a significant portion of these initiatives is developer-funded, the overall variances heavily reflect these market conditions, supply chain constraints that deferred metering work, and the accompanying timing of contribution recoveries.
System Renewal, Net	1,429	1,991	562	39%	System Renewal variances were primarily shaped by the strategic acceleration of lifecycle replacement programs, specifically for poles and transformers. These activities were increased to intentionally offset a major underspend caused by the county-directed deferral of the Road Authority project on Innisfil Beach Road, stretching from 10th Sideroad to Yonge Street. Utilizing readily available pole and transformer materials allowed these projects to move forward efficiently, helping to balance the budget against supply chain constraints that delayed switch and switchgear programs, as well as other coordination-driven project deferrals.
System Service, Net	4,419	4,506	87	2%	System Service variances were primarily impacted by timing differences in major station and transmission work, including progression of the Barrie Area Transformer Upgrade and reclassification of certain transmission-related work, as well as delays in fault indicator and switch installation programs.
General Plant, Net	1,022	969	-53	-5%	General Plant variances varied due to timing of IT and corporate investments, deferral of selected system upgrades,

Category	2024				Justification
	Plan.	Act.	Var.		
	$ '000		%		
					and one-time facility improvements, partially offset by fleet purchases and previously ordered equipment deliveries. The 2024 variance was also influenced by the completion of certain projects in 2023 that were initially expected to continue into 2024. As a result, some planned 2024 expenditures did not occur, with the lower level of spending also helping to offset higher expenditures incurred in 2023.
Total Expenditure, Net	9,120	17,594	8,474	93%	Net capital variances reflect aggregate variances across all capital categories, primarily driven by timing differences in capital program execution and development-related activity, partially offset by capital contribution variability.
Capital Contributions[21]	-24,260	-17,062	7,198	-30%	Capital contribution variances in 2024 were driven by the timing and scope of customer- and developer-driven connection activity, including the pace of subdivision development and the timing of associated contribution collections.
Total Expenditure, Gross	33,380	34,657	1,277	4%	Gross expenditures varied due to timing differences in capital program execution across all categories, including deferral and advancement of selected projects and development-related activity.
System O&M	2,812	3,220	408	15%	System O&M variances in 2024 were driven by fluctuations in planned and reactive maintenance activities, as well as changes in workload volumes associated with customer-initiated locate requests, DIRs, and patrol-style trouble calls. InnPower typically uses a three-year rolling average and historical forecasting to predict these expenditures, but lower interest rates and increased consumer spending on

[21] Following 2024 rebasing, InnPower identified a correction to the methodology for forecasting System Access Capital Contributions, as described in Exhibit 1, Section 3, pages 26–27. The historical Plan and Actual values have been adjusted to reflect this correction. Accordingly, where both values have been adjusted for a historical year, the resulting variance does not reflect the impact of the forecasting methodology issue. As described in Exhibit 1, InnPower corrected this methodology as part of its 2027 Cost of Service Application, with the corrected methodology applied beginning with the 2027 forecast and thereafter.

Category	2024				Justification
	Plan.	Act.	Var.		
	$ '000		%		
					home upgrades drove request volumes significantly higher than anticipated. While rising general labor rates also increased the overall cost of inspection and maintenance programs, this inflation was a secondary factor compared to the sheer volume of customer-driven activity and shifting patrol-style trouble calls.

5.4.1.1.4 2025 Variance Analysis

Table 5.4-5 below provides a summary of InnPower's 2025 capital expenditure variances by investment category, comparing approved plan values to the actual expenditures. Explanations are provided for material variances exceeding +/-10% of materiality threshold (i.e., $81,000), with a focus on key drivers.

Table 5.4-5: 2025 Budget Variance Explanations

Category	2025				Justification
	Plan.	Act.	Var.		
	$ '000		%		
System Access, Net	2,202	10,014	7,812	355%	System Access variances in 2025 were primarily driven by timing differences in customer- and developer-driven connection work, including expansion and New Services activity. The overage was specifically driven by two external factors: (1) the energization of six subdivisions that were unknown at the time of the last application, resulting in approximately 1,007 anticipated connections. These subdivision projects were externally driven and contributed to higher-than-planned System Access expenditures; and (2) the completion of the deferred Innisfil Beach Road, 10th Sideroad to Yonge Street project, which was executed as a Road Authority job in 2025.
System Renewal, Net	1,593	2,811	1,218	76%	System Renewal variances were driven by timing differences in lifecycle replacement programs – including the completion of deferred transformer work and the reprioritization of pole, switch, and recloser programs – partially offset

Category	2025				Justification
	Plan.	Act.	Var.		
	$ '000		%		
					by budget reallocations. However, the overage was heavily driven by significant storm-related activity following a major ice storm, as well as an incremental $70,000 variance for a switchgear replacement; due to supply availability constraints, an SD-style gear had to be utilized instead of the budgeted PME-style gear.
System Service, Net	4,654	5,281	627	13%	System Service variances were primarily driven by timing differences in station and transmission work, including progression of Barrie Area system reinforcement and staged execution of 44 kV projects, as well as delays in select station rehabilitation and switch installation activities. The variance was also driven by preliminary work associated with the Transmission Line and Transformer Station projects, including higher-than-anticipated costs related to the Environmental Assessment and transmission line activities.
General Plant, Net	730	850	120	16%	General Plant variances were driven by timing differences in IT and corporate investments, including cybersecurity and infrastructure upgrades, partially offset by deferral of ERP-related initiatives and delayed fleet replacements. The deferral of ERP-related initiatives was a significant contributor to the variance, resulting in lower-than-planned expenditures in 2025. In addition, spending levels continued to reflect efforts to address the higher expenditures incurred in 2023.
Total Expenditure, Net	9,179	18,955	9,776	107%	Net capital variances reflect aggregate variances across all capital categories, primarily driven by timing differences in capital program execution and development-related activity.

Category	2025				Justification
	Plan.	Act.	Var.		
	$ '000		%		
Capital Contributions[22]	-19,899	-19,831	68	0%	Capital contributions variances were consistent with forecast, with minor timing differences in customer- and developer-driven connection activity.
Total Expenditure, Gross	29,078	38,787	9,709	33%	Gross capital variances varied due to timing differences in capital program execution across all categories.
System O&M	3,000	3,459	459	15%	System O&M variances in 2025 were driven by fluctuations in planned and reactive maintenance activity and storm response requirements, as well as changes in workload volumes associated with customer-initiated locate requests, DIRs, and patrol-style trouble calls. The primary driver of the overage was a significant increase in DIRs following the ice storm, including a high volume of customer requests related to generator and GenerLink installations, which resulted in higher-than-anticipated maintenance activity volumes.

5.4.1.1.5 2026 Variance Analysis

Table 5.4-6 below provides a summary of InnPower's 2026 capital expenditure variances by investment category, comparing the approved plan to the current forecast of year-end actual expenditures. As 2026 is still ongoing, the forecasted expenditures are based on the best information available at the time of filing and are subject to change as projects progress and are completed. Explanations are provided for material variances exceeding +/-10% of materiality threshold (i.e., $81,000), with a focus on key drivers.

[22] Following 2024 rebasing, InnPower identified a correction to the methodology for forecasting System Access Capital Contributions, as described in Exhibit 1, Section 3, pages 26–27. The historical Plan and Actual values have been adjusted to reflect this correction. Accordingly, where both values have been adjusted for a historical year, the resulting variance does not reflect the impact of the forecasting methodology issue. As described in Exhibit 1, InnPower corrected this methodology as part of its 2027 Cost of Service Application, with the corrected methodology applied beginning with the 2027 forecast and thereafter.

Table 5.4-6: 2026 Budget Variance Explanations

Category	2026				Justification
	Plan.	Bgt.	Var.		
	$ '000		%		
System Access, Net	1,915	3,760	1,845	96%	System Access variances in 2026 were primarily driven by timing differences in customer- and developer-driven connection work, including expansion developments and New Services activity. This variance also reflects variability in subdivision work—with five subdivisions forecasted to be energized in 2026—and their associated capital contributions.
System Renewal, Net	1,633	1,189	-444	-27%	System Renewal variances in 2026 were driven by timing differences in lifecycle replacement programs, including accelerated transformer replacement activity and increased reactive and safety-driven work, partially offset by reallocation of funding across pole, switch, and switchgear programs; with the recloser, switch, and switchgear replacement programs receiving 50% funding through the NRCan program, resulting in lower net capital expenditures.
System Service, Net	4,902	6,666	1,764	36%	System Service variances in 2026 were primarily driven by timing differences in transmission and station projects, including Barrie Area reinforcement and staged execution of 44 kV infrastructure and voltage conversion initiatives, partially offset by deferral of select station rehabilitation and communication-related projects. The variance was also impacted by increased material and labour costs, which contributed to higher project execution costs.
General Plant, Net	803	1,539	736	92%	General Plant variances in 2026 were driven by timing differences in IT and corporate capital investments, including cybersecurity, ERP-related initiatives with eligible Engineering IT initiatives, including Blue Frame, FLISR, Polaris, and LiDAR, receiving 50% funding through the NRCan program, resulting in lower net capital expenditures, partially

Category	2026				Justification
	Plan.	Bgt.	Var.		
	$ '000		%		
					offset by delayed fleet and equipment replacements.
Total Expenditure, Net	16,922	32,926	16,004	95%	Net capital variances reflect aggregate variances across all capital categories, primarily driven by timing differences in capital program execution and development-related activity across System Access, System Service, and System Renewal programs.
Capital Contributions[23]	-7,669	-19,772	-12,103	158%	Capital contributions varied significantly due to timing and volume differences in customer- and developer-driven connection activity, reflecting the pace of subdivision development and timing of associated contribution collections.
Total Expenditure, Gross	16,922	32,926	16,004	95%	Gross capital variances varied primarily due to timing differences in capital program execution across all categories, including development-driven and system reinforcement-related work.
System O&M	3,406	3,766	360	11%	System O&M expenditures varied due to fluctuations in planned and reactive maintenance activity, including storm response requirements and timing of field maintenance work, as well as workload variability associated with customer-initiated locate requests, DIRs, and patrol-style trouble calls.

5.4.1.2 Forecast Expenditures

An analysis of a distributor's capital expenditures for the DSP's forecast period.

5.4.1.2.1 Overall Forecast Expenditures

The distributor must provide an analysis of a distributor's capital expenditures for the DSP's forecast period.

[23] Following 2024 rebasing, InnPower identified a correction to the methodology for forecasting System Access Capital Contributions, as described in Exhibit 1, Section 3, pages 26–27. The historical Plan and Actual values have been adjusted to reflect this correction. Accordingly, where both values have been adjusted for a historical year, the resulting variance does not reflect the impact of the forecasting methodology issue. As described in Exhibit 1, InnPower corrected this methodology as part of its 2027 Cost of Service Application, with the corrected methodology applied beginning with the 2027 forecast and thereafter.

Table 5.4-7 and Figure 5.4-1 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 5.4-7: Forecast Net Expenditures by Investment Category (Incl. BATU & TS Project)

Category	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000						
System Access	7,211	11,219	8,564	8,742	8,779	44,515	37%
System Renewal	2,281	5,610	4,941	6,151	5,104	24,087	20%
System Service	8,511	4,998	2,502	12,507	11,362	39,880	33%
General Plant	3,557	3,347	1,362	1,661	2,146	12,073	10%
Total Expenditure, Net	**21,560**	**25,175**	**17,368**	**29,060**	**27,391**	**120,555**	**100%**

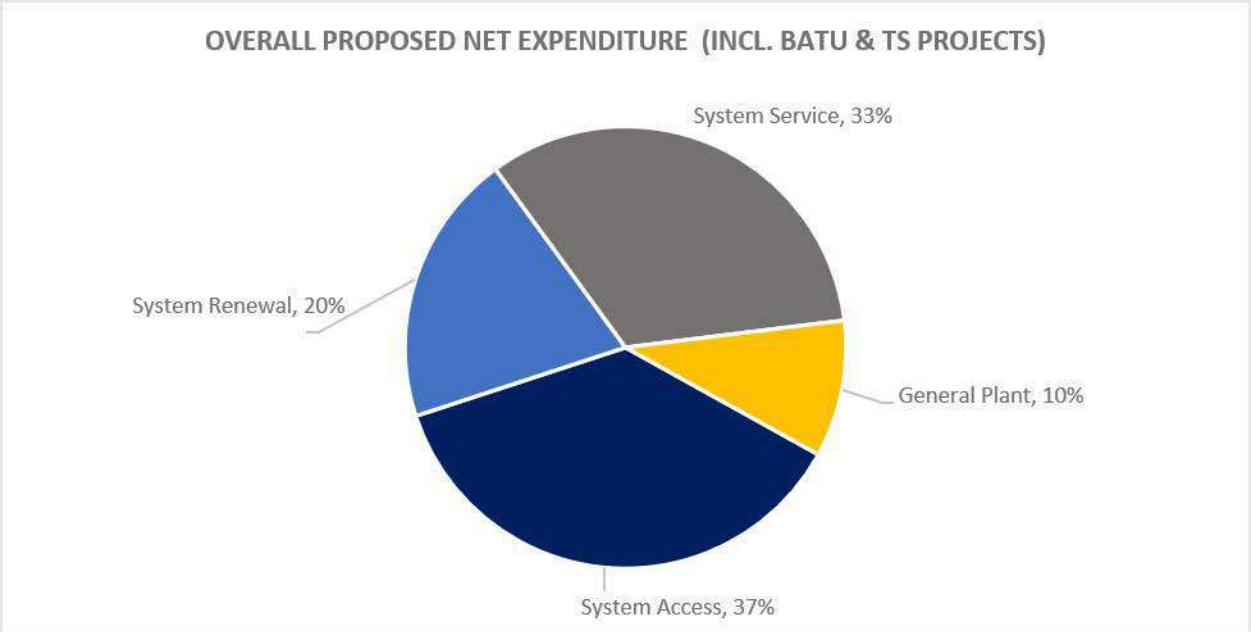

Figure 5.4-1: Forecasted Net Expenditures by Investment Category (Incl. BATU & TS Project)

When including costs from both the BATU project contributions and new TS Project, System Access is the largest planned capital expenditure over the 2024–2028 forecast period representing 37% of overall spending, which is followed by System Service at 33%, System Renewal at 20%, and General Plant at 10%.

When excluding both the TS Project and BATU project costs, System Access remains the largest planned capital expenditure over the 2024–2028 forecast period representing 46% of overall spending, followed by System Renewal at 25%, System Service at 16%, and General Plant at 13%, as shown in the Table 5.4-8 and Figure 5.4-2. Forecast costs by investment category are detailed further in the following sub-sections.

Table 5.4-8: Forecast Net Expenditures by Investment Category (Excl. BATU, Excl. TS Project)

Category	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000						
System Access	7,211	11,219	8,564	8,742	8,779	44,515	46%
System Renewal	2,281	5,610	4,941	6,151	5,104	24,087	25%
System Service	4,511	4,998	2,502	2,507	1,362	15,880	16%
General Plant	3,557	3,347	1,362	1,661	2,146	12,073	13%
Total Expenditure, Net	**17,560**	**25,175**	**17,368**	**19,060**	**17,391**	**96,555**	**100%**

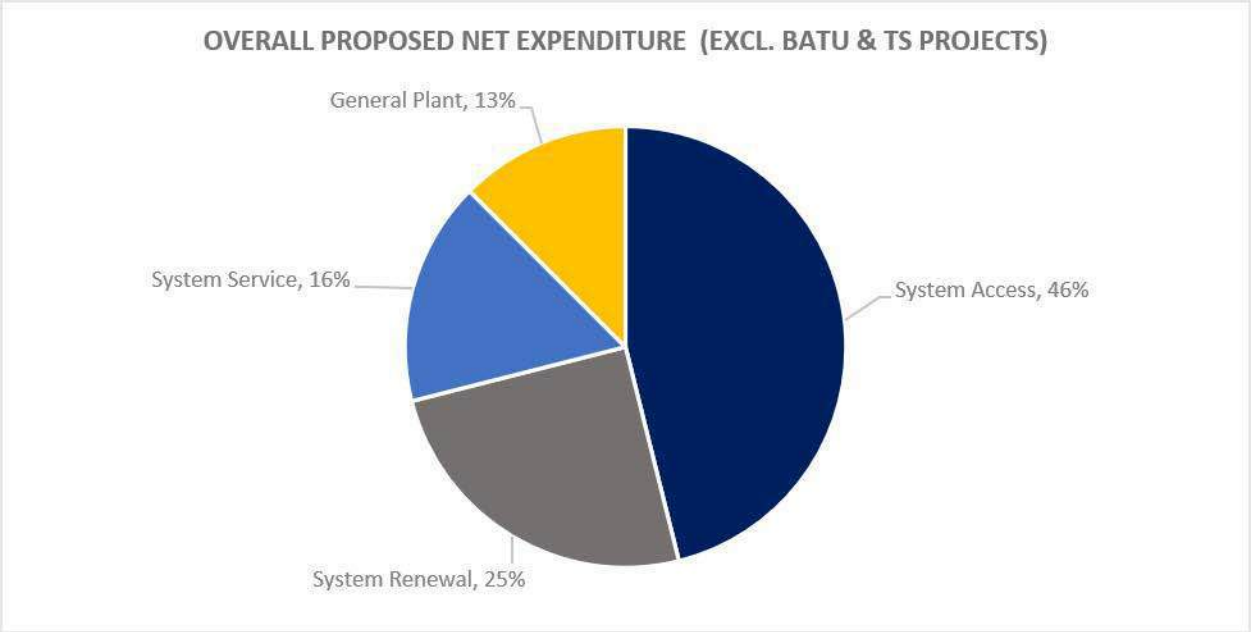

Figure 5.4-2: Forecasted Net Expenditures by Investment Category (Excl. BATU & TS Project)

5.4.1.2.2 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 is driven by the needs of external parties and are considered mandatory. Investments in System Access are captured in Table 5.4-9, Figure 5.4-3, and Figure 5.4-4 below.

Table 5.4-9: Forecast Net System Access Expenditures

Category	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		

IPCSA – 100% Recoverable[24]	0	0	0	0	0	0	0%
IPCSA – Subdivisions	3,751	7,534	4,799	4,799	4,799	25,681	58%
IPCSA02 – Road Authority	2,924	3,012	3,102	3,196	3,291	15,526	35%
IPCSA05 – Metering	536	673	663	748	689	3,308	7%
Total Expenditure, Net	**7,211**	**11,219**	**8,564**	**8,742**	**8,779**	**46,515**	**100%**

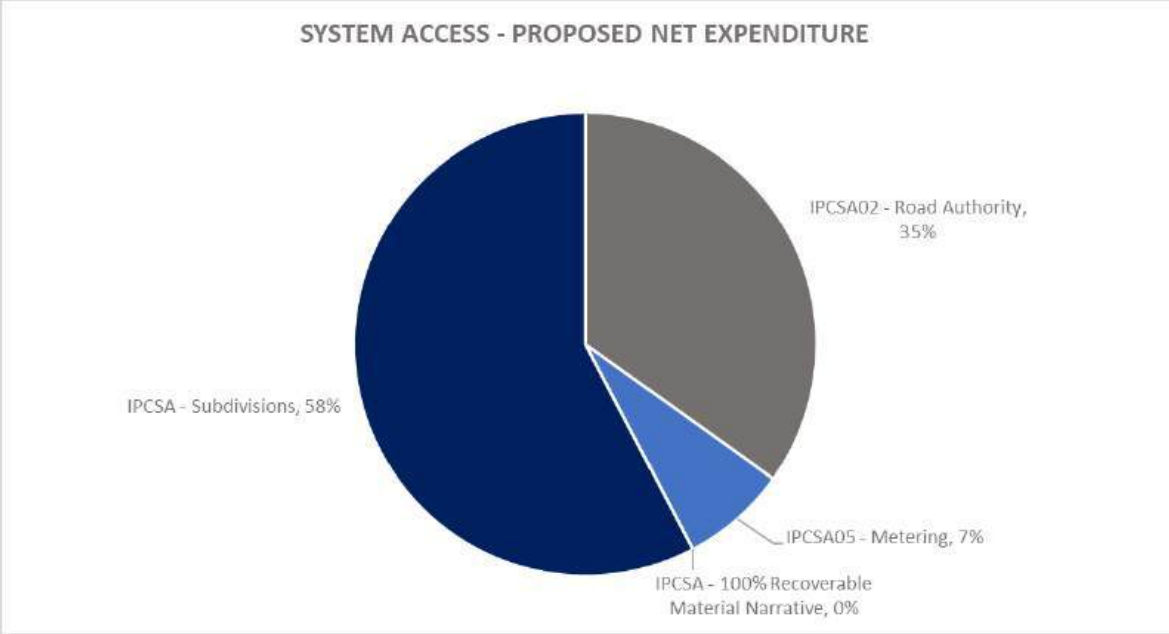

Figure 5.4-3: Forecasted Net System Access Expenditures by Project

[24] IPCSA – 100% Recoverable projects are fully recoverable through capital contributions; therefore, the net expenditures associated with these projects are reflected as zero.

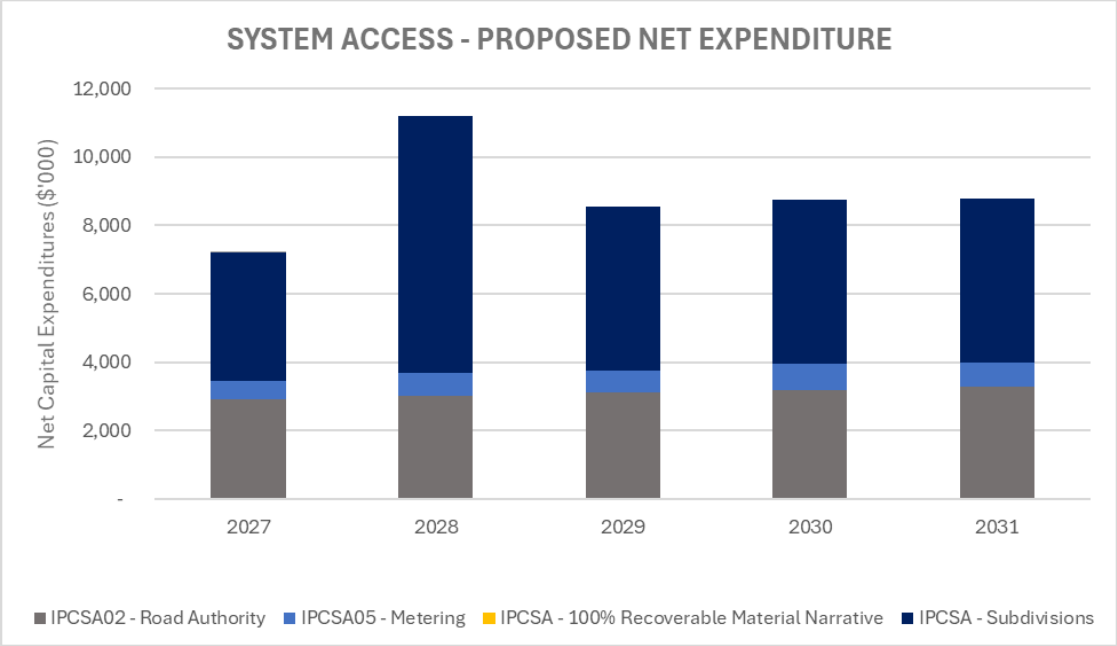

Figure 5.4-4: Forecasted Net System Access Expenditures by Project

Net System Access is the largest planned capital expenditure over the 2027–2031 forecast period representing 46% 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.

- **Subdivisions:** Representing approximately 58% of the expenditures within this category, subdivision investments relate to the extension and servicing of distribution infrastructure required to accommodate residential and mixed-use development growth within InnPower's service territory. These projects typically include the installation of primary and secondary distribution assets, transformers, and associated infrastructure necessary to connect new subdivision developments in accordance with customer growth requirements and municipal planning activities.

  Several larger subdivision developments are anticipated to proceed within InnPower's service area over the forecast period, including:

  - Everwell South Barrie Phase 2, a subdivision with an anticipated build-out of 162 homes expected to be energized in 2026.
  - Sleeping Lion Phase 4, a subdivision with an anticipated build-out of 155 homes expected to be energized in 2026.
  - Lefroy Phase 2 – Block 126, a subdivision with an anticipated build-out of 60 homes expected to be energized in 2026.
  - Mattamy Salem, a multi-phase subdivision development with an anticipated build-out of 378 homes in both Innisfil and South Barrie, expected to be energized in 2026.
  - Gilford Estates, a subdivision with an anticipated build-out of 33 homes expected to be energized in 2027.
  - Webster Boulevard Condo, a condominium development with an anticipated build-out of 91 homes on Webster Boulevard, expected to be energized in 2027.

- Friday Harbour Hotel and Conference Centre, an industrial development with an expected energization in 2027.
- Hewitt Gate, a subdivision development with an anticipated build-out of 144 homes on Mapleview Drive, expected to be energized in 2027.
- Mapleview South Block, a subdivision development with an anticipated build-out of 100 homes, expected to be energized in 2027.
- Mapleview Park, a subdivision development with an anticipated build-out of 266 homes over multiple phases on Mapleview Drive East, expected to be energized in 2027.
- Hewitt Creek, a subdivision development with an anticipated build-out of 900 homes on Mapleview Drive, expected to be energized in 2027.
- Innisfil Executive Estates Stroud, a subdivision development with an anticipated build-out of 21 homes on Sunnybrae Avenue, expected to be energized in 2027.
- 911 Lockhart, a subdivision development with an anticipated build-out of 24 homes on Lockhart Road.
- Watersands, a subdivision development with an anticipated build-out of 380 homes on McKay Road West, expected to be energized in 2027.
- Gateway Casino, a large-scale mixed-use industrial and hospitality development, featuring a primary casino phase followed by a subsequent hotel expansion. The casino is expected to be energized in 2027.
- Belle Aire Beach Townhome, a residential and commercial development with an anticipated build-out of 75 homes expected to be energized in 2027.
- Northern Transformer, a large-scale industrial and manufacturing development which is expected to be energized in 2028.
- GG (9 Mile) Phase 3, a subdivision development with an anticipated build-out of 41 homes, expected to be energized in 2028.
- Innisvillage Phase 2C, a subdivision development with an anticipated build-out of 38 homes, expected to be energized in 2028.
- Mapleview South Block 192, a commercial development expected to be energized in 2028.
- LSAMI Phase 4, a commercial development expected to be energized in 2028.
- Bistro 6 Elements Phase 1, a condominium development with an anticipated build-out of 96 homes, expected to be energized in 2028.
- 7131 5th Side Road, a commercial development expected to be energized in 2028.
- 1015 Innisfil Beach Road, a subdivision development with an anticipated build-out of 100 homes, expected to be energized in 2028.
- Big Bay Point Subdivision, a subdivision development with an anticipated build-out of 43 homes, expected to be energized in 2028.

- Sandry Creek Estate, a subdivision development with an anticipated build-out of 133 homes, expected to be energized in 2028.
- Country Wide Homes at Salem 27, a subdivision development with an anticipated build-out of 194 homes, expected to be energized in 2028.
- Bellaire Beach Road, a residential and commercial development with an anticipated build-out of 122 homes expected to be energized in 2028.
- Harbour Street, a subdivision development with an anticipated build-out of 70 homes, expected to be energized in 2028.

Between 2026 and 2028, InnPower anticipates approximately 35 new subdivision developments, comprising a mix of residential detached homes, condominiums, and industrial developments. The total expected residential build-out is 3,200+ units. Forecasted amount for 2029 to 2031 are all based on average energization amounts due from 2025 to 2028.

- **Road Authority:** Representing approximately 35% of the expenditures within this category, Road Authority projects are the second largest driver of spending. These projects primarily involve the relocation of overhead ("OH") and/or underground ("UG") distribution infrastructure required to accommodate municipal and Ministry of Transportation ("MTO") road widening and road reconstruction initiatives. Several larger Road Authority projects are anticipated to occur within InnPower's service area over the forecast period, including:
  - County Road 4 Widening – Phases 3 to 7: This multi-phase program includes utility relocations required to support roadway widening works across multiple segments. Phase 3 is scheduled between InnPower's southern limit and County Road 89 (2026–2027), Phase 4 between the InnServices building and 9th Line (2027), Phase 5 in the Stroud area (2027–2028), and Phases 6 and 7 between the InnServices building and County Road 89 (2028–2029).
  - County Road 53 Widening: Relocation works between County Road 21 and the Barrie city limits, scheduled for 2026 to accommodate roadway expansion activities.
  - County Road 27 Widening: Relocation of InnPower infrastructure between County Road 21 and County Road 90, scheduled from 2028 to 2029.
  - County Road 54 and Line 6 Intersection (Innisfil): Relocation works at the identified intersection to support planned roadway improvements, scheduled for 2031.
- **Metering:** These expenditures account for approximately 7% of the expenditures within this category and relate to the supply, installation, replacement, and maintenance of revenue metering equipment installed at customer service points for retail settlement and billing purposes for customers connected to InnPower's distribution system. These investments support the accurate measurement of electricity consumption, ongoing customer connections, and meter lifecycle replacement requirements across InnPower's service territory.
- **100% Recoverable Projects:** On a net basis, the 100% recoverable program represents 0% of the expenditures within this category, as project costs are fully recoverable through contributions from third parties, including developers and customers.

  This program includes expenditures associated with new service connections, expansion developments, and other large customer-driven developments anticipated within InnPower's service territory over the forecast period. Key developments currently planned include the Hewitt and Salem developments.

In conclusion, System Access expenditures increase over the forecast period primarily due to subdivision activity, which represents the largest share of planned investments. The increase in 2028 is driven by higher subdivision spending. Subdivisions account for approximately 67% of total System Access expenditures in that year. Major contributors include Country Wide Homes at Salem 27, Mapleview South Block 192, and Sandy Creek Estate.

Road Authority and Metering expenditures remain relatively stable over the forecast period. Following the increase in 2028, System Access expenditures decline in 2029 and stabilize through 2031 as subdivision spending returns to more typical annual levels.

5.4.1.2.3 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 Table 5.4-10, Figure 5.4-5, and Figure 5.4-6 below.

Table 5.4-10: Forecast Net System Renewal Expenditures

Category	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
IPCSR01 – Capital Trouble Calls and Emerging Projects	465	479	493	508	523	2,469	10%
IPCSR02 – Transformer Replacement Program	247	255	262	270	278	1,312	5%
IPCSR03 – Pole Replacement Program	418	431	444	457	471	2,220	9%
IPCSR04 – Reclosure Replacement Program	200	206	212	218	225	1,061	4%
IPCSR05 – Switch Replacement Program	129	132	136	140	145	682	3%
IPCSR06 – Switchgear Replacement Program	140	143	146	160	163	751	3%
IPCSR07 – Voltage Regulators	390	-	-	-	-	390	2%
IPCSR13 – Animal Mitigation	72	74	76	79	81	383	2%
IPCSR14 – Oil Re-inhibit Treatment	70	91	91	118	118	488	2%
IPCSR16 – Sandy Cove Rear Lot Conversion	150	3,800	3,080	4,200	3,100	14,330	59%
Total Expenditure, Net	**2,281**	**5,610**	**4,941**	**6,151**	**5,104**	**24,087**	**100%**

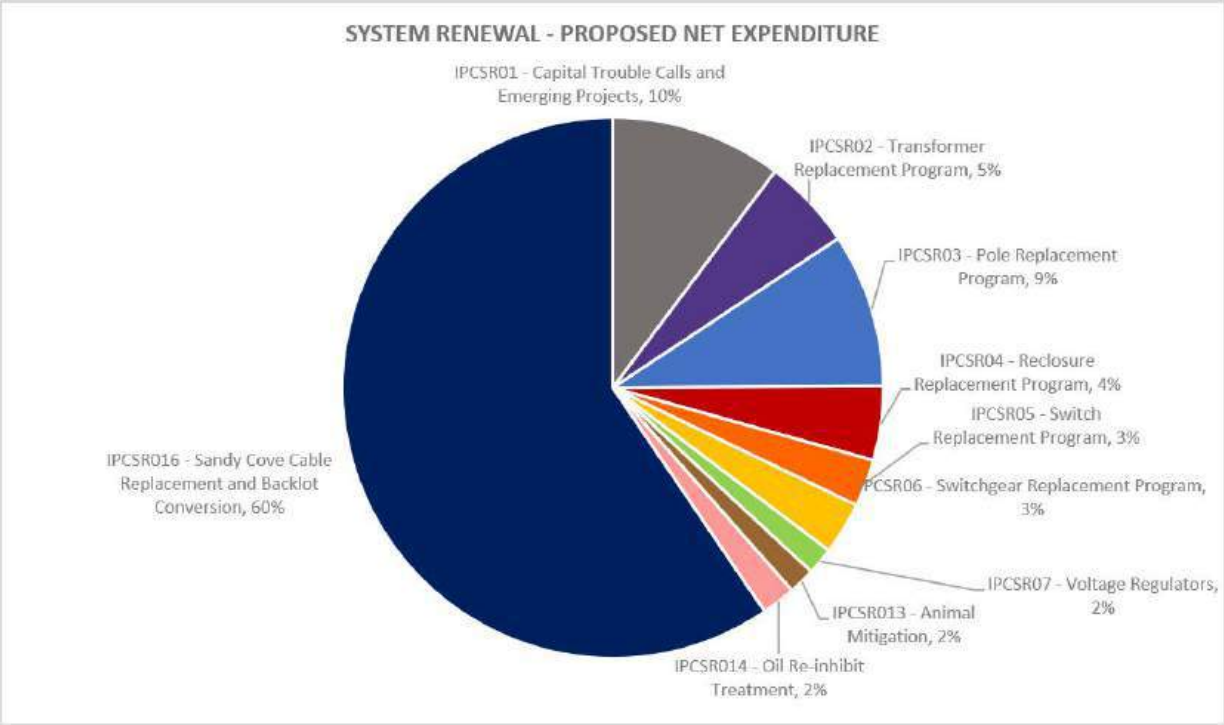

Figure 5.4-5: Forecasted Net System Renewal Expenditures by Project

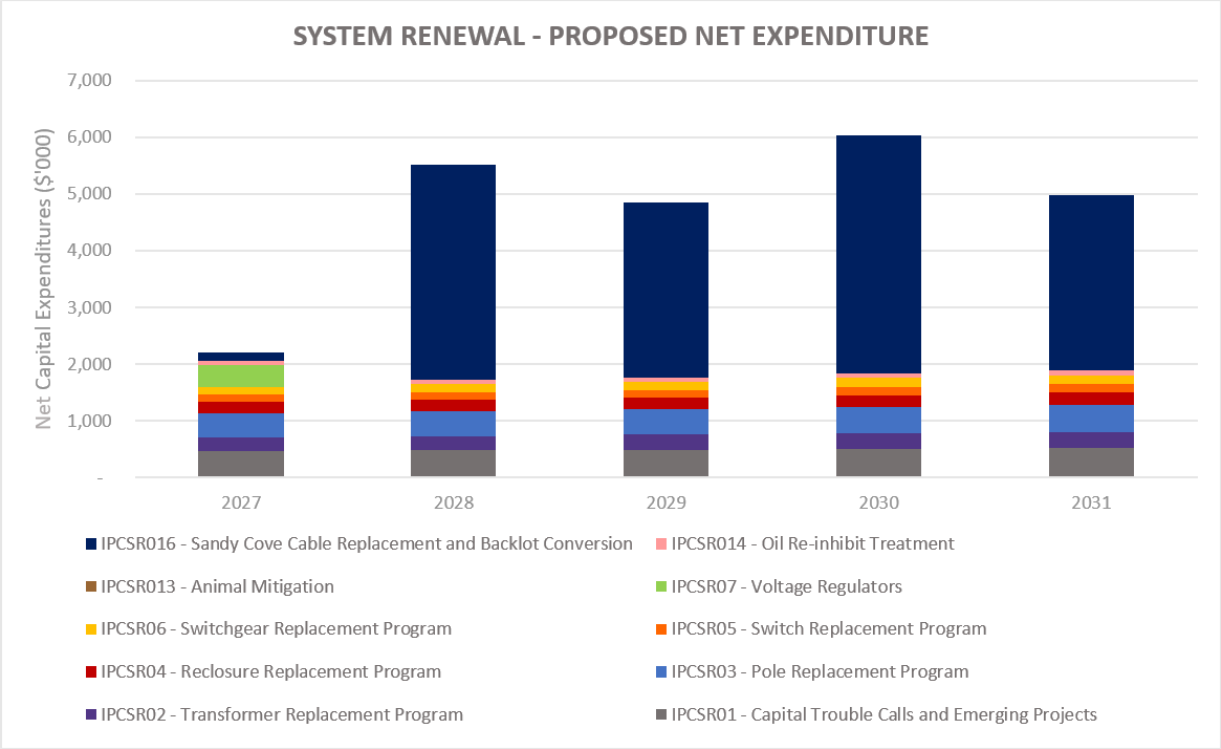

Figure 5.4-6: Forecasted Net System Renewal Expenditures by Project

System Renewal is the second largest planned capital expenditure over the 2027–2031 forecast period representing 25% 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:

- **Capital Trouble Calls and Emerging Projects (10% 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.
- **Transformer Replacement Program (5% 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.
- **Pole Replacement Program (9% 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.
- **Recloser Replacement Program (4% of forecast net expenditures):** Involves 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 (3% 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.
- **Switchgear Replacement Program (3% of forecast net expenditures):** Includes planned replacement of distribution system switchgears based on results from the annual visual inspection program and ACA.
- **Voltage Regulator Program (2% of forecast net expenditures):** Involves the installation, replacement, or refurbishment of voltage regulators on the distribution system to maintain appropriate voltage levels and support power quality and system performance under varying load conditions.
- **Animal Mitigation (2% 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.
- **Oil Re-inhibit Treatment Program (2% of forecast net expenditures):** Includes the treatment or re-inhibition of insulating oil in applicable distribution equipment to maintain dielectric properties and extend the useful service life of in-service assets, based on condition assessment and testing results.
- **Sandy Cove Rear Lot Conversion Program (59% of forecast net expenditures):** Associated with the conversion or relocation of existing rear lot electrical distribution assets to front lot or more accessible configurations to improve safety, accessibility, maintainability, and compliance with utility design standards.

System Renewal expenditures vary over the forecast period, with the lowest level in 2027 and higher levels in 2028 and 2030. Investment is driven by condition-based replacement of end-of-life assets and targeted renewal programs, including poles, transformers, reclosers, switches, and switchgear, as well as unplanned capital work through Capital Trouble Calls and Emerging Projects.

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 13% 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.

The planned level of investment supports timely replacement of assets based on condition and risk, reducing the likelihood of equipment failure and supporting system reliability.

5.4.1.2.4 System Service: Including BATU and TS Project

Expenditures in the System Service category are driven by the need to ensure the distribution system continues to meet its operational objectives, including reliability, grid flexibility, and the integration of distributed energy resources ("DERs"), while supporting anticipated customer demand requirements. Investments are also influenced by the condition of station assets and the need for ongoing refurbishment and upgrades. System Service investments are summarized in Table 5.4-11, Figure 5.4-7 and Figure 5.4-8 below.

Table 5.4-11: Forecast Net System Service Expenditures (Incl. BATU & TS Projects)

Category	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
IPCSS05 - 27.6kV OH Dist Fault Indicators	79	110	125	125	-	439	1%
IPCSS07 - 44kV Switch Commissioning	75	25	25	25	-	150	0%
IPCSS08 - Communication Improvement	106	106	179	179	179	748	2%
IPCSS11 - InnPower TS	-	-	-	10,000	10,000	20,000	50%
IPCSS12 - Station Rehab	2,516	3,011	404	404	404	6,740	17%
IPCSS17 - BATU	4,000	-	-	-	-	4,000	10%
IPCSS19 – Voltage Conversion from 8.32kV to 27.6kV	1,500	1,500	1,500	1,500	500	6,500	16%
IPCSS21 - SCADAMATE / VIPER Commissioning	19	25	25	25	25	118	0%
IPCSS22 - 44kV Switch Installation	59	59	76	76	76	345	1%
IPCSS24 – Normal Open Point Switch Installation	158	163	168	173	178	840	2%
Total Expenditure, Net	**8,511**	**4,998**	**2,502**	**12,507**	**11,362**	**39,880**	**100%**

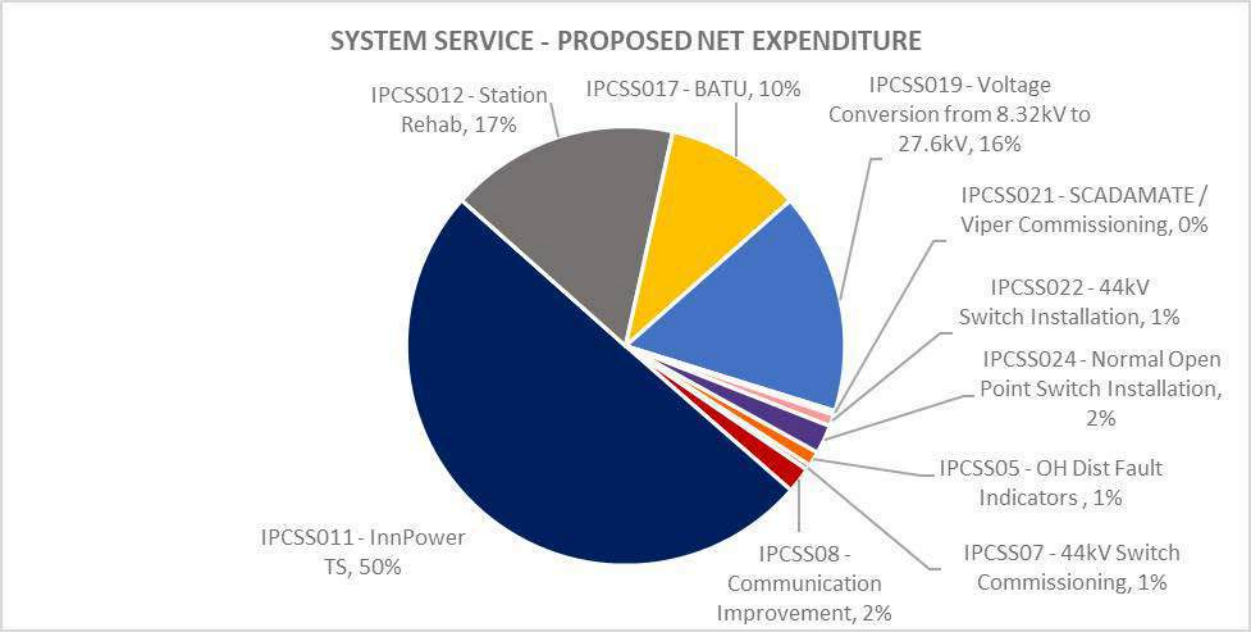

Figure 5.4-7: Forecasted Net System Service Expenditures by Project

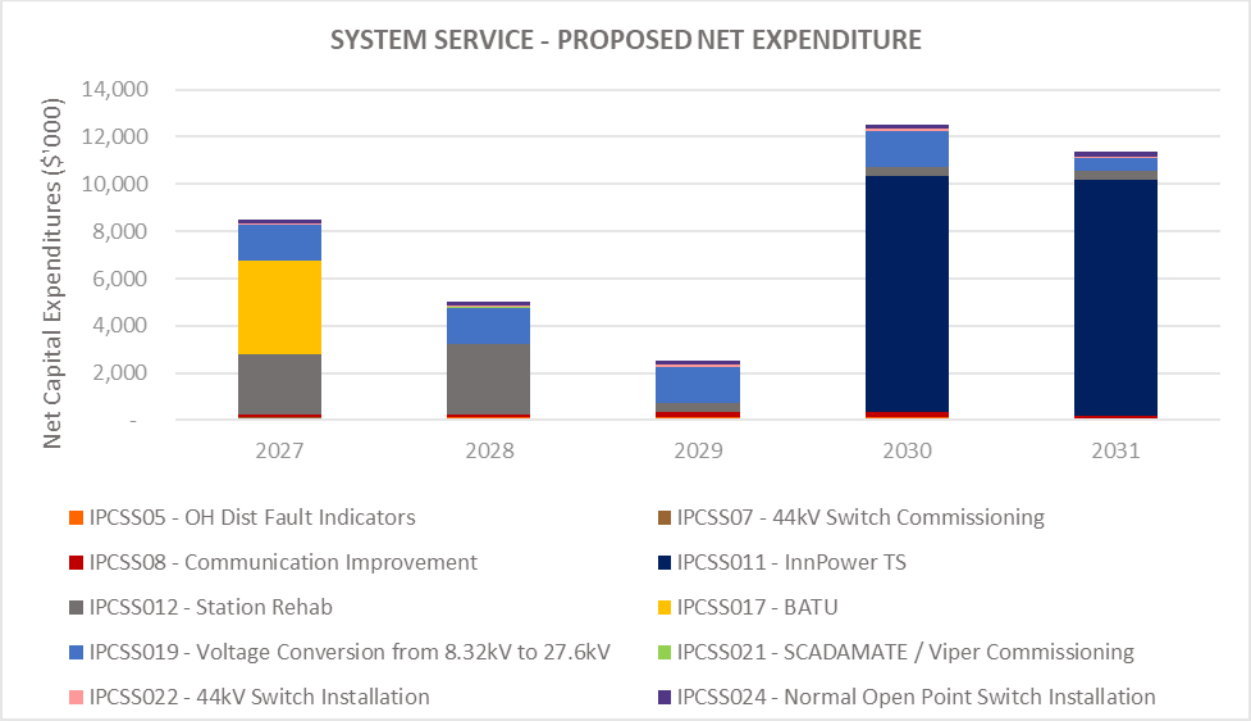

Figure 5.4-8: Forecasted Net System Service Expenditures by Project

When including the BATU and TS Project costs, these projects account for 60% 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 Essa TS, and expanding Barrie TS to include new 230/44 kV transformation facilities. The project supports increased transmission supply capacity to accommodate load growth in the South Barrie and Innisfil areas and addresses end-of-life constraints on existing infrastructure.

The project was approved by the OEB in April 2020[25] with an approved in-service date (ISD) of June 2022 and an initial total project cost of $91 million, including an InnPower capital contribution of $14.1 million.

Approved Scope, Schedule, and Baseline Assumptions:

At approval, the project scope included station upgrades at Essa TS and Barrie TS, and construction of new 230 kV transmission circuits (E28/E29) with removal of existing 115 kV circuits (E3B/E4B). The project was planned to address regional capacity constraints identified through prior system planning studies.

Post-Approval Schedule and Cost Revisions (Initial Update):

Following approval, HONI updated the project schedule due to procurement delays, supply chain constraints, and emerging construction complexity. As a result, the in-service date was revised from June 2022 to December 2023.

During this period, updated cost estimates increased from $91 million to approximately $125 million, driven by commodity price escalation, material cost increases, and revised construction sequencing requirements. InnPower's capital contribution was correspondingly updated to approximately $20.6 million. These revisions reflected evolving market conditions and early construction execution challenges.

Subsequent Updates:

More recent HONI forecasting, based on the March 2025 Discounted Cash Flow (DCF) update and the March 2026 update, indicates a further revised project cost of approximately $128.75 million and a revised cutover date of May 2026. InnPower's updated capital contribution is approximately $20 million, reflecting the latest cost allocation methodology and updated project schedule.

Project Progress:

- **Essa TS:** Construction at Essa TS includes expansion of the 230 kV yard, reconfiguration of transmission circuits, and removal of end-of-life transformer equipment. As of earlier reporting periods, approximately 75% of 230 kV bus work and 400 metres of trenching had been completed, with remaining work scheduled during planned outage windows. Schedule extensions have been driven by outage coordination requirements and construction sequencing complexity.
- **Barrie TS:** Barrie TS works include expansion to support new 230/44 kV facilities and removal of legacy 115 kV infrastructure. Construction progress has included installation of helical piles and initiation of duct bank excavation; however, progress has been impacted by groundwater conditions. Additional scope refinements were required due to previously unidentified soil contamination, necessitating remediation activities and revised construction methodologies,

[25] 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.

including specialized foundation works. These conditions have contributed to increased construction complexity and schedule adjustments.

- **Transmission Line Works (E28/E29 and E3B/E4B):** The transmission line scope includes construction of new 230 kV double circuit lines (E28/E29) and decommissioning of existing 115 kV circuits (E3B/E4B). Cost increases have been driven by material price escalation, particularly for tower steel and conductors, along with supply chain constraints and long-lead procurement requirements. While procurement efficiencies were identified through vendor agreements, overall project costs remain elevated relative to initial estimates due to prevailing market conditions.

Summary:

Since approval, the BATU project has experienced sequential updates to scope execution timing, in-service date, and cost estimates reflecting evolving construction conditions, market-driven pricing impacts, and construction complexity. Despite these changes, the project continues to advance under HONI execution, and InnPower's capital contribution reflects the most recent approved forecasting assumptions.

New TS Project Update

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 2030 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 2x83MVA TS and connection to the new 230 kV transmission lines that will be available upon the completion of the BATU project in 2025.

In coordination with HONI, it was determined that the new TS would be constructed, maintained, and owned by a newly established transmission company. InnPower is expected to provide a capital contribution to the new company, 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).

5.4.1.2.5 System Service: Excluding BATU and TS Project

When excluding BATU and InnPower TS projects, System Service expenditures represent 16% of overall spending over the 2027–2031 forecast period. Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet its operational objectives, including system capacity, grid flexibility, and the integration of distributed energy resources (“DERs”), while supporting anticipated customer electricity requirements. These investments also support system standardization and enhancements to station functionality and operational capability. Investments in System Service are shown in Table 5.4-12, Figure 5.4-9, and Figure 5.4-10 below.

Table 5.4-12: Forecast Net System Service Expenditures (Excl. BATU & TS Projects)

Category	Forecast					Total ($ ‘000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ ‘000	$ ‘000	$ ‘000	$ ‘000	$ ‘000		
IPCSS05 - 27.6kV OH Dist Fault Indicators	79	110	125	125	-	439	3%
IPCSS07 - 44kV Switch Commissioning	75	25	25	25	-	150	1%
IPCSS08 - Communication Improvement	106	106	179	179	179	748	5%
IPCSS12 - Station Rehab	2,516	3,011	404	404	404	6,740	42%
IPCSS19 – Voltage Conversion from 8.32kV to 27.6kV	1,500	1,500	1,500	1,500	500	6,500	41%
IPCSS21 - SCADAMATE / VIPER Commissioning	19	25	25	25	25	118	1%
IPCSS22 - 44kV Switch Installation	59	59	76	76	76	345	2%
IPCSS24 – Normal Open Point Switch Installation	158	163	168	173	178	840	5%
Total Expenditure, Net	**4,511**	**4,998**	**2,502**	**2,507**	**1,362**	**15,880**	**100%**

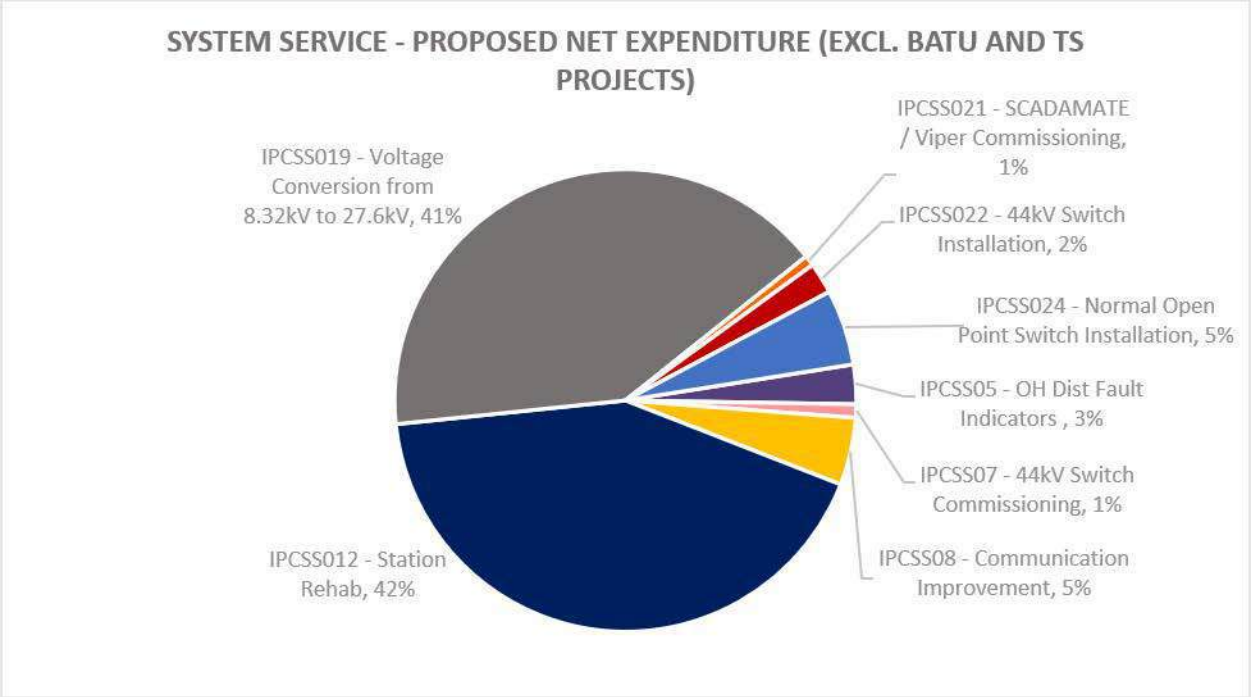

Figure 5.4-9: Forecasted Net System Service Expenditures by Project (Excl. BATU and TS Projects)

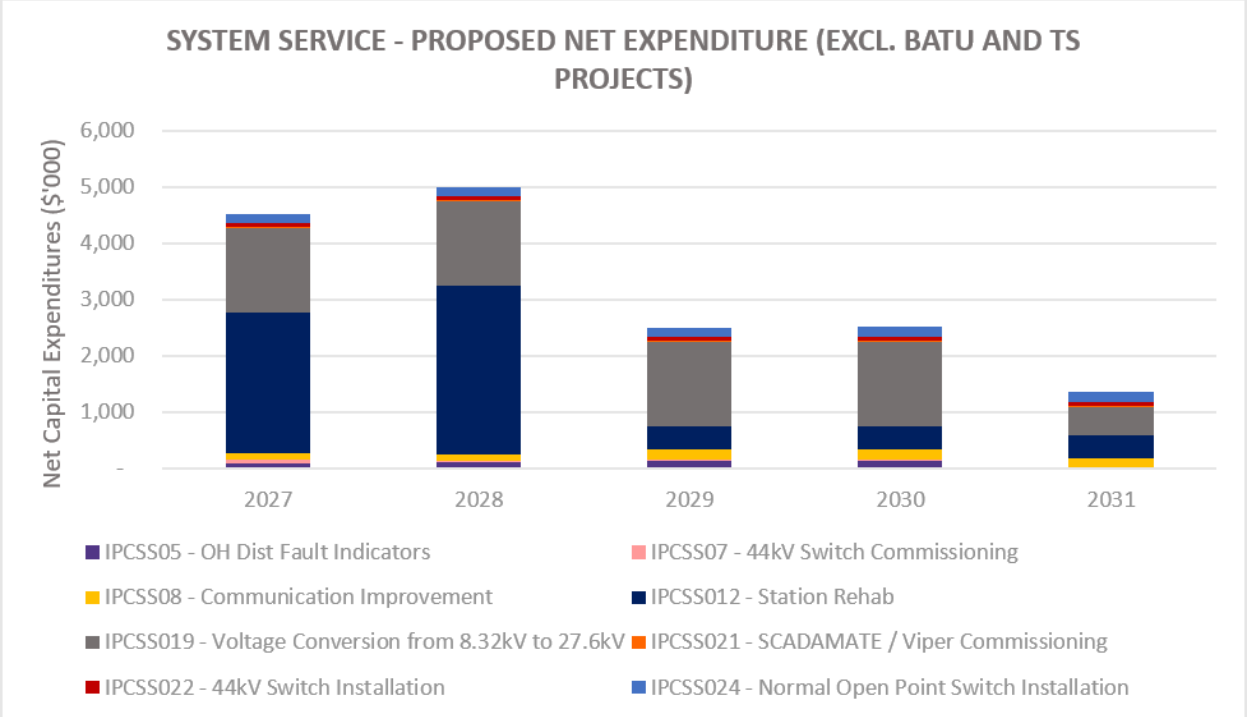

Figure 5.4-10: Forecasted Net System Service Expenditures by Project (Excl. BATU and TS Projects)

- **Station Rehab (42%):** When excluding the BATU and TS Project costs, Station Rehab represents the largest portion 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 2026–2031 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 2027–2028, which are not recovered by third-party contributions.
- **Voltage Conversion from 8.32kV to 27.6kV (41%):** This program represents the second largest driver within this category and includes system conversion activities required to transition portions of the distribution system from 8.32kV to 27.6kV. This includes associated planning, coordination, and implementation activities required to support voltage standardization and system performance requirements.
- **Normal Open Point Switch Installation (5%) and Communication Improvement (5%):** The Normal Open Point Switch Installation 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. The Communication Improvement 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.
- **Overhead Distribution Fault Indicators (3%):** This program involves the installation and commissioning of new 27.6 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 2027 and beyond.
- **44kV Switch Installation (2%):** This includes installation of 44kV switch infrastructure to support system expansion, operational flexibility, and reliability. This includes associated civil and electrical installation activities required for deployment, including foundation works, equipment pads, duct banks/conduit installation, grounding, and site preparation activities.
- **44kV Switch Commissioning (1%):** This includes commissioning activities associated with 44kV switch infrastructure to support safe integration into the distribution system. This includes testing, verification, and operational readiness activities required prior to energization.
- **SCADAMATE / VIPER Commissioning (1%):** This includes commissioning and integration activities for SCADAMATE and VIPER systems to support the operational functionality of automated switching and control equipment within the distribution system.

The observed trend in System Service spending from 2027 to 2031 is primarily driven by the Station Rehabilitation program. This program addresses distribution station capacity requirements to accommodate new load growth and includes the replacement and rehabilitation of end-of-life equipment, including power transformers. Third-party contributions to the Station Rehabilitation program in 2024 and 2025 reduce net expenditures in those years, contributing to higher forecast period spending relative to prior years. System Service expenditures are also influenced by the timing of other program activities, including the restart of the 27.6 kV fault indicator program in 2027 and the completion of the Normal Open Point Switch Installation program in 2027.

5.4.1.2.6 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 Table 5.4-13, Figure 5.4-11 and Figure 5.4-12 below.

Table 5.4-13: Forecast Net General Plant Expenditures

Category	Forecast					Total ($ '000)	Percent of Total
	2027	2028	2029	2030	2031		
	$ '000	$ '000	$ '000	$ '000	$ '000		
IPCGP01 - IT Hardware	418	591	274	216	127	1,625	14%
IPCGP02 - IT Software	1,488	445	222	205	215	2,575	21%
IPCGP04 - Building & Fixtures	295	95	95	95	295	875	7%
IPCGP06 - Engineering IT	321	50	50	550	250	1,222	7%
IPCGP07 – Measuring Tools and Equipment	190	246	246	320	320	1,322	11%
IPCGP12 - Fleet	845	1,920	475	550	1,065	4,855	40%
Total Expenditure, Net	**3,557**	**3,347**	**1,362**	**1,936**	**2,271**	**12,473**	**100%**

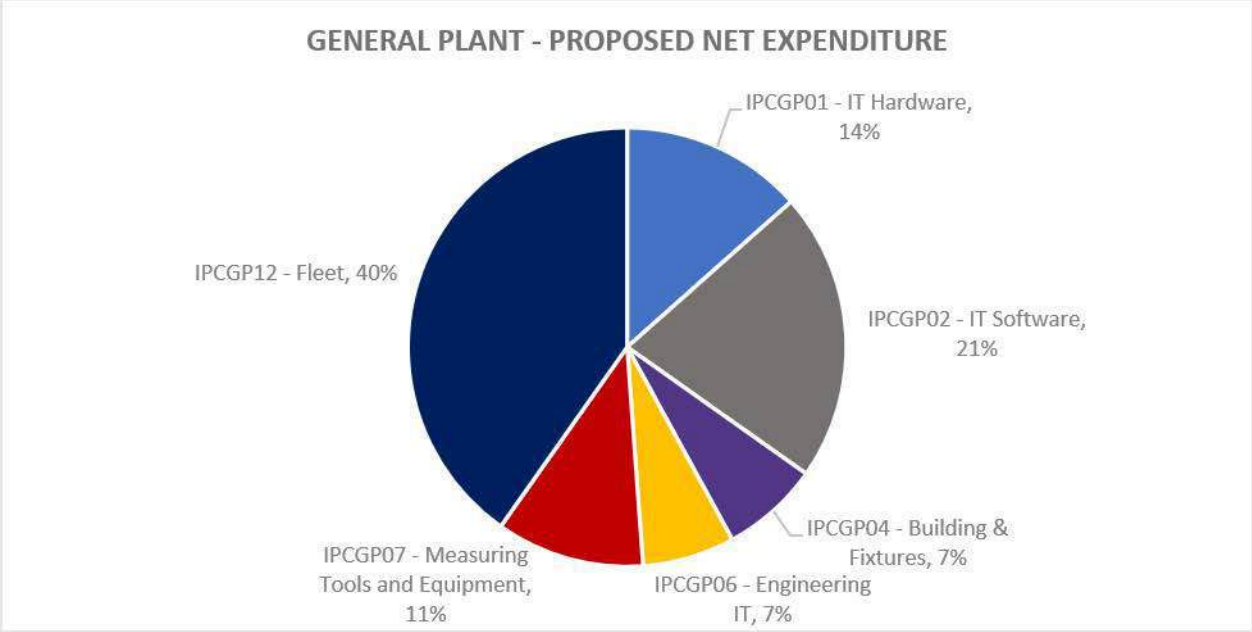

Figure 5.4-11: Forecasted Net General Plant Expenditures by Project

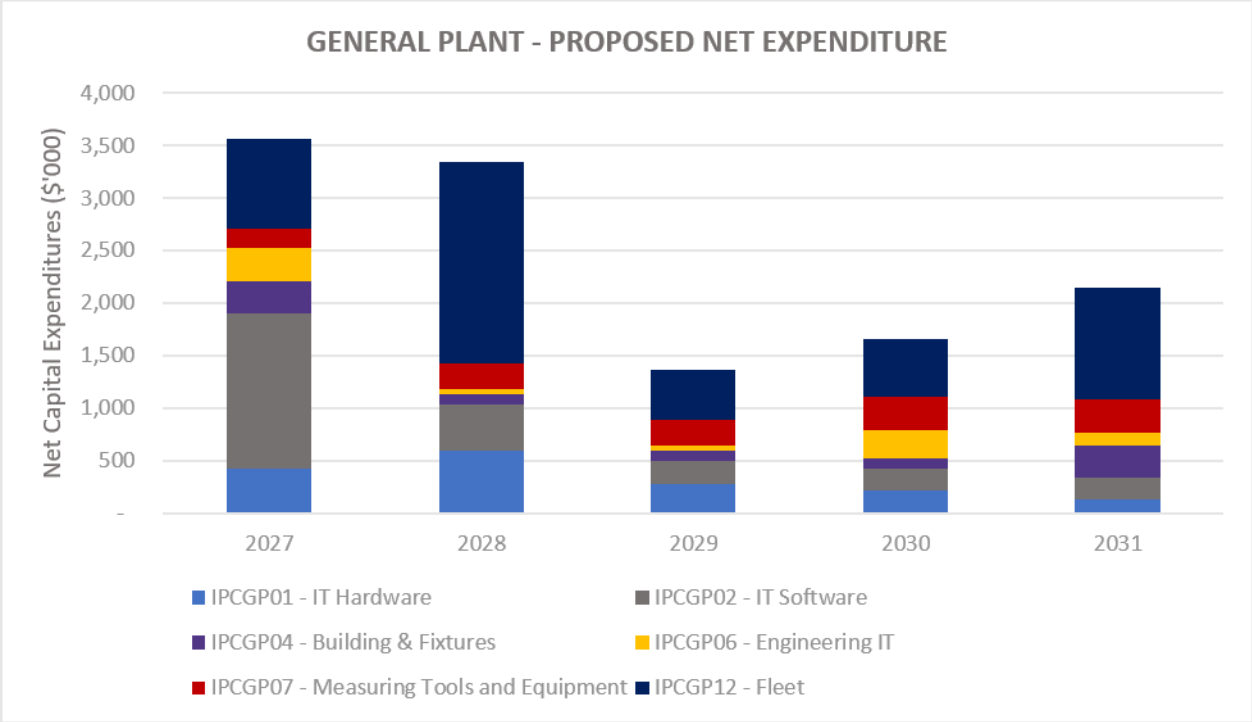

Figure 5.4-12: Forecasted Net General Plant Expenditures by Project

hen excluding the BATU and TS Project costs, nNet General Plant expenditures represent 13% 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 40%, 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 2027 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 14% and 21%, 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 budget is allocated amongst the following programs:

- **IT Hardware and IT Software (35%):** Includes investments in information technology hardware and software to support ongoing operations, system reliability, and cybersecurity.
    - **Hardware:** Includes equipment for new hires, replacement of failed or end-of-life infrastructure, network backup storage devices, station modems, and ongoing device and server/network refreshes.
    - **Software:** Includes system upgrades and enhancements such as mCare, ERP and CIS investments, workforce management tools, SCADA-related initiatives, and cybersecurity improvements, along with miscellaneous replacements and workload relief applications.
- **Fleet (40%):** Includes investment in utility vehicles and equipment to support field operations, including new additions and replacements of aging units such as bucket trucks, pickup trucks, vans, loaders, and specialized equipment such as stringing equipment, as well as multi-year procurement payments. This includes planned replacement of 90+ ft bucket trucks with phased

installment payments from 2027–2029 and 2030–2032, with deliveries expected in 2029 and 2032, respectively. Additional fleet replacements include a 65 ft bucket truck with installment payments from 2031–2033 and delivery expected in 2033, as well as a replacement RBD scheduled for delivery in 2028.

- **Measuring Tools and Equipment (11%):** Includes procurement of specialized equipment to support system monitoring, diagnostics, and maintenance activities, including infrared (IR) camera equipment for distribution stations.
- **Engineering IT (7%):** Includes information systems and tools, including SCADA, asset management systems, engineering analysis tools, and newer technologies such as Blueframe, LiDAR, POLARIS (with NRCan funding support), and FLISR.
- **Buildings and Fixtures (7%):** Comprises general investments and improvements to buildings and associated infrastructure, including planned replacements and upgrades identified through building needs assessments, annual air conditioning unit replacements, yard infrastructure such as a Quonset hut, and roof replacements.

Year-over-year fluctuations in General Plant expenditures are primarily driven by the timing of major Fleet and Information Technology investments. Spending is higher in 2027 and 2028 due to IT Software and IT Hardware investments and scheduled Fleet replacements. Expenditures decline in 2029 and 2030 as these larger investment cycles taper. Spending increases again in 2031, driven by renewed Fleet replacement requirements and periodic refresh of IT and facility-related assets. These investments support ongoing operational requirements, including asset management systems, field operations, and corporate support infrastructure.

5.4.1.2.7 Investments with Project Lifecycle Greater than One Year

For capital investments that have a project life cycle 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 work-in-progress until the capital project is in service. Therefore, capitalization will only occur at the end of the project once it is in service.

5.4.1.3 Comparison of Forecast and Historical Expenditures

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 5.4-13, InnPower's System Access forecast average is just 16% greater than the historical average. This reflects the overall level of investment required to support customer-driven system expansion over the 2027–2031 planning period.

The System Access forecast is primarily driven by subdivision development, road authority projects, and metering-related work, with subdivisions representing the largest component of planned investment. The historical System Access trend is variable year over year due to the timing of customer connection requests, externally initiated subdivision and relocation projects, metering upgrades, and third-party works. The forecast reflects the timing and distribution of these activities over the planning period.

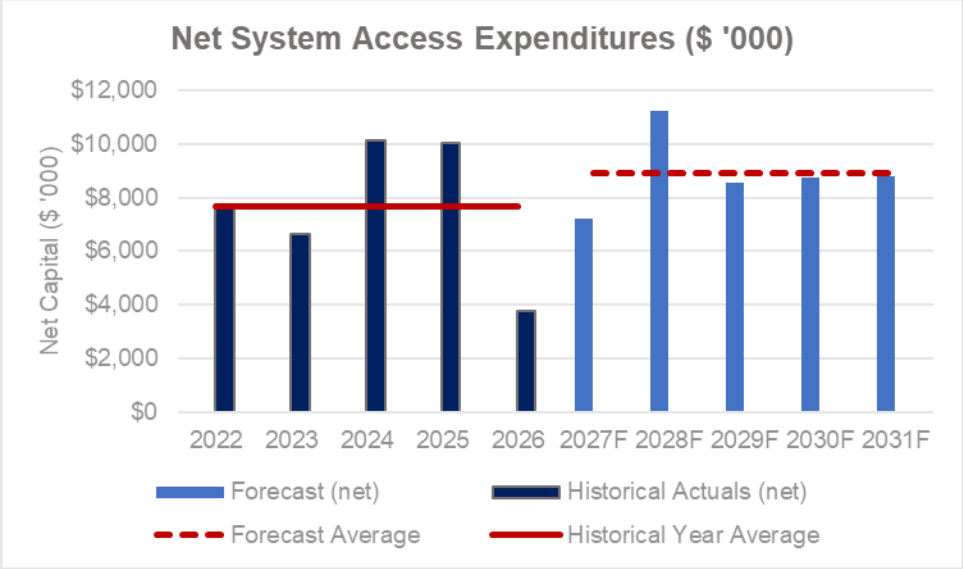

Figure 5.4-13: System Access Comparative Expenditures

5.4.1.3.2 System Renewal

As shown in Figure 5.4-14 below, InnPower's System Renewal forecast average is approximately 166% higher than the historical average, although in part to mitigate ratepayer impacts, the bulk of the increase associated with much needed renewal projects are scheduled to occur after the test year. System Renewal expenditures are impacted by planned capital investments and the objective to address condition-based maintenance requirements within the asset system to meet customer expectations for performance, safety, and reliability.

The increase in forecast System Renewal spending reflects a planned increase in asset renewal activity over the 2027–2031 planning period, consistent with ongoing asset management requirements and recommendations identified through asset condition assessments. This includes continued efforts to maintain system reliability and address aging infrastructure. 59% of the forecasted expenditures are attributed to the Sandy Cove cable replacement and backlot conversion, this project contributes significantly to the elevated expenses in 2028 and 2030 resulting in those years exceeding the forecasted average. Historical System Renewal expenditures were relatively stable and lower, reflecting a more limited level of renewal activity during the historical period. The forecast level of System Renewal investment also reflects the need to balance investment across competing capital priorities, including system access and other capital programs, while continuing to meet safety and reliability objectives.

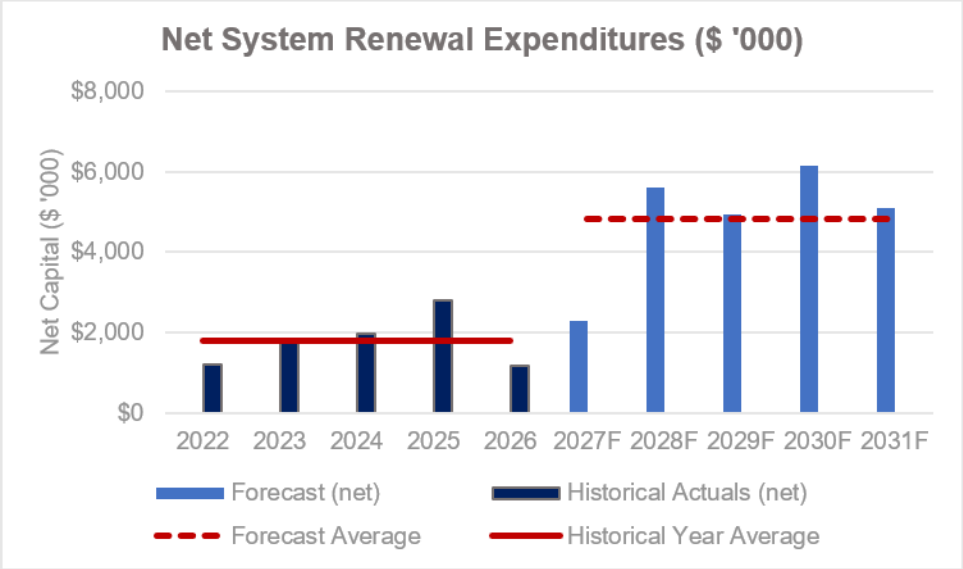

Figure 5.4-14: System Renewal Comparative Expenditures

5.4.1.3.3 System Service

As shown in the Figure 5.4-15 and Figure 5.4-16 below, InnPower's System Service forecast average is approximately 64% higher than the historical average when including BATU contributions and the TS Project. This increase is primarily driven by the timing of the TS Project (2030-2031), as well as a one-time BATU expenditure in 2027.

When excluding BATU contributions and the TS Project, the System Service forecast average is approximately 37% higher than the historical average. This increase is driven by station rehabilitation work, end-of-life equipment replacement, and system automation initiatives, including fault indicator programs and related station upgrades to support system reliability and performance. This reflects the need to maintain system reliability and support station capacity requirements while accommodating planned capital investment requirements over the forecast period. Historical System Service expenditures have varied year over year due to the timing and prioritization of station rehabilitation and upgrade projects, as well as alignment with broader system requirements and operational planning.

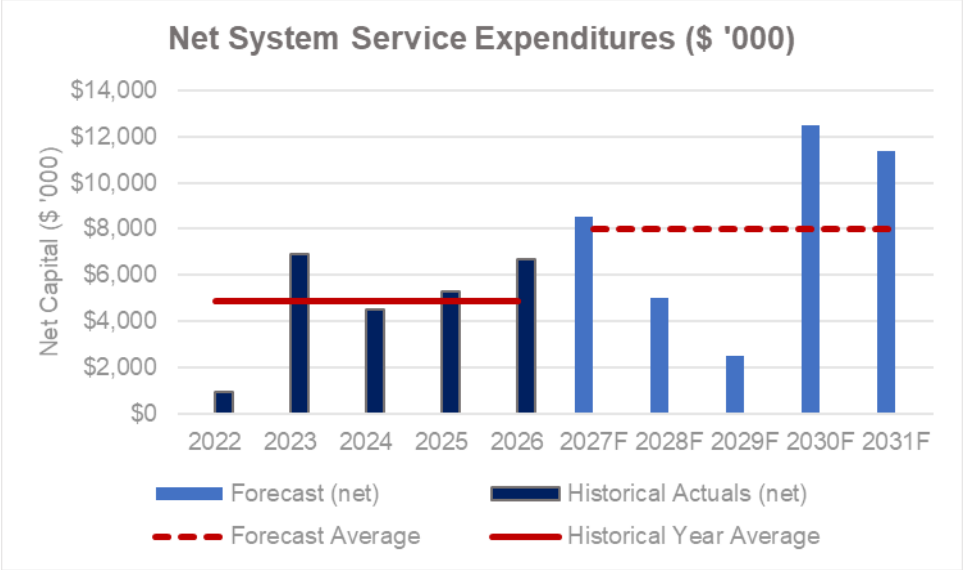

Figure 5.4-15: System Service Comparative Expenditures (Incl. BATU & TS Projects)

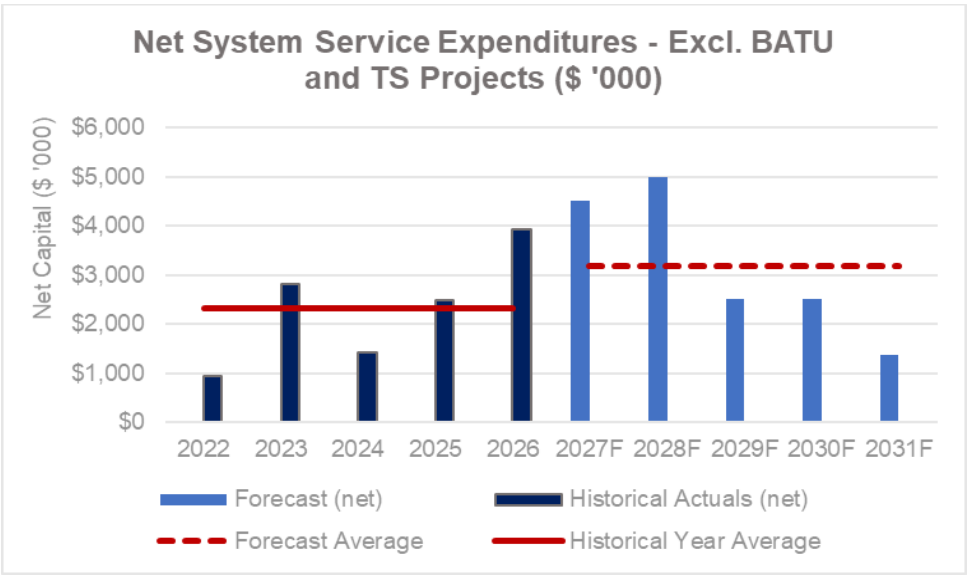

Figure 5.4-16: System Service Comparative Expenditures (Excl. BATU & TS Projects)

5.4.1.3.4 General Plant

InnPower continues to use its capital planning framework to address requirements associated with General Plant assets, including fleet, information technology systems, and operational support equipment. As shown in Figure 5.4-17 below, InnPower's General Plant forecast average is approximately 105% higher than the historical average. This increase is primarily driven by planned replacement and renewal of fleet assets and information technology infrastructure over the forecast period. The forecast also reflects continued investment in operational support systems to maintain effective service delivery and support evolving business requirements. Variations in spending over the forecast period are primarily due to the timing of fleet replacements, IT lifecycle refresh requirements, and the sequencing of operational equipment needs. Historical General Plant expenditures have

varied due to the timing of fleet replacements, equipment leasing decisions, and periodic IT and operational asset refresh cycles.

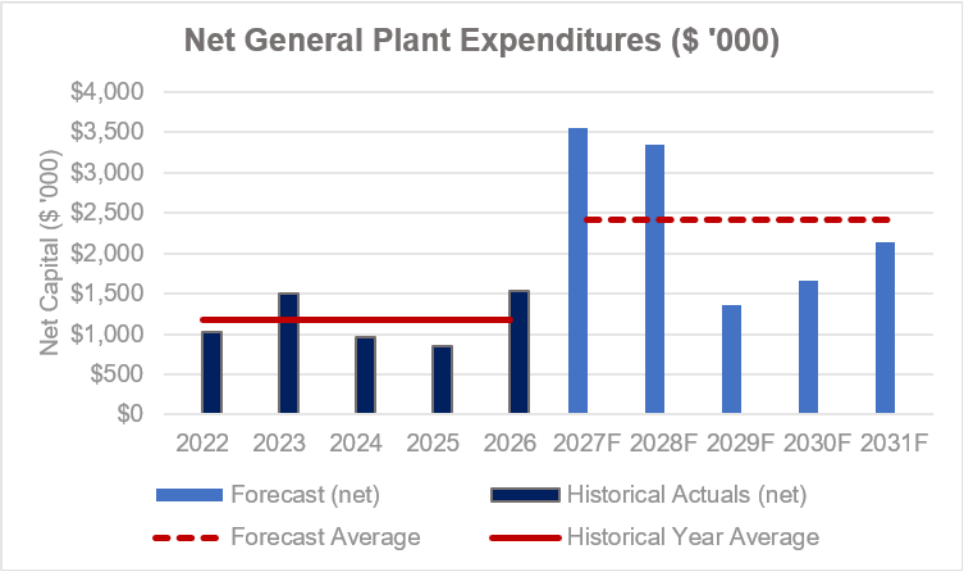

Figure 5.4-17: General Plant Comparative Expenditures

5.4.1.3.5 Overall Capital Expenditures

As shown in the Figure 5.4-18 below, InnPower's overall net capital expenditures over the 2027–2031 planning period are approximately 55% higher than the historical average. The forecast increase reflects the combined effect of higher investment requirements across these programs to support system reliability, asset renewal, and ongoing service obligations. Year-over-year variations in the forecast are driven by the timing of major projects and the sequencing of capital investments across the various programs. Overall, the increase in forecast capital expenditures reflects InnPower's continued investment in maintaining and upgrading its electrical system to ensure safe and reliable service to customers, while addressing asset renewal requirements and supporting ongoing system needs.

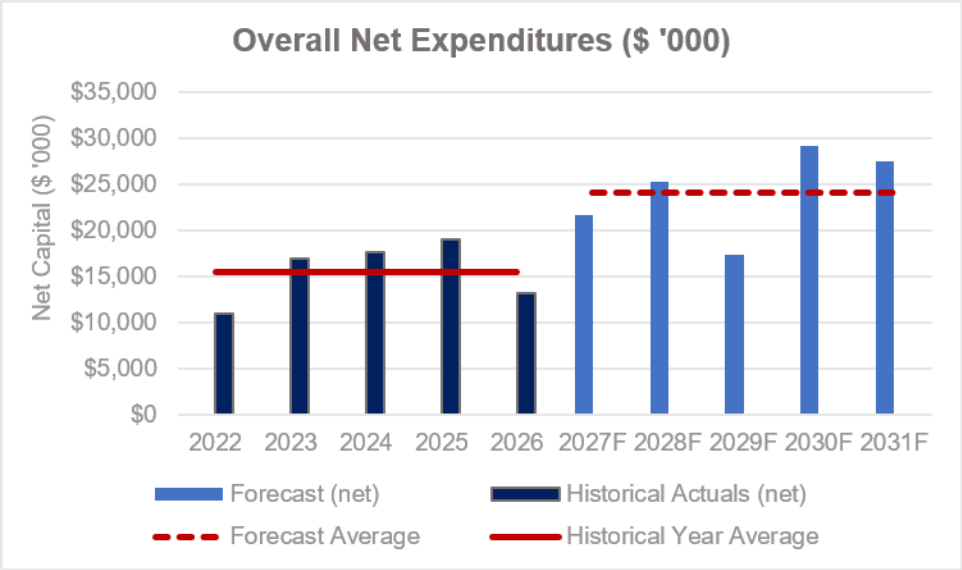

Figure 5.4-18: Overall Comparative Expenditures

As shown in the Figure 5.4-19, InnPower's overall net capital expenditures excluding BATU and TS Projects over the 2027–2031 planning period are approximately 52% higher than the historical average.

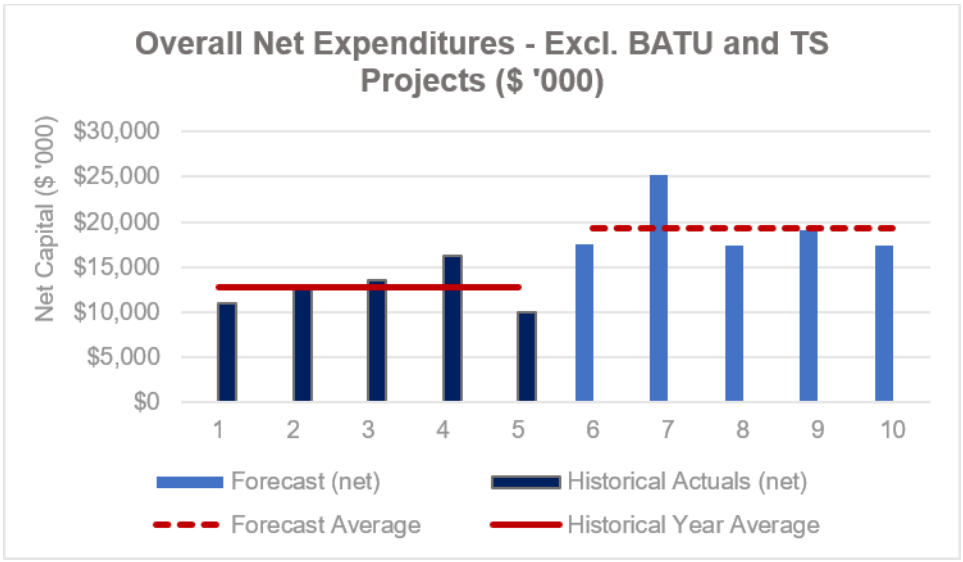

Figure 5.4-19: Overall Comparative Expenditures (Excl. BATU and TS Projects)

5.4.1.4 Important Modifications to Capital Programs Since Last DSP

A summary of any important modifications to typical capital programs since the last DSP (e.g., changes to individual asset strategies). Modifications could also include regulatory drivers (e.g., impacts on capital spending resulting from the December 2024 amendment to the DSC, extending the revenue horizon for residential connections to 40 years and extending the maximum connection horizon to 15 years for housing developments).

Since the previous DSP filing, InnPower has not made any fundamental changes to its overall capital planning approach or asset management framework. Asset health assessment methodologies and asset prioritization practices remain consistent with the prior DSP. The increase in capital requirements since the previous DSP is primarily driven by specific program needs, external requirements, and changes in delivery costs rather than changes to InnPower's overall capital planning approach.

Within the Station Rehabilitation program, InnPower has incorporated the replacement of an end-of-life transformer at Sandy Cove DS with a new 5 MVA unit. This update reflects refinements in asset condition assessments and supports continued reliability and performance of station infrastructure. The modification is consistent with InnPower's ongoing asset management approach, which prioritizes renewal activities based on asset health and system requirements.

No other material changes have been made to the capital programs overall. However, certain capital programs have increased due to specific drivers, including road authority and subdivision requirements, fleet replacement needs, and increased material and labour costs. Increases in material and labour costs have influenced delivery planning, resulting in efforts to group asset replacement activities where feasible, provided such grouping is consistent with asset condition requirements and delivers potential cost efficiencies. These cost pressures have affected program delivery requirements but have not resulted in changes to the underlying asset management methodologies or prioritization practices.

Key targeted initiatives introduced since the last DSP include the Sandy Cove rear-lot conversion program, intended to proactively address rear-lot transformer and cable failure risks; voltage conversion initiatives to improve system reliability and support organic load growth in the BBP area; and selective fleet and bucket truck acquisitions to support safe access to assets located further from road corridors, in accordance with road authority requirements. These targeted initiatives, particularly the Sandy Cove rear-lot conversion program, represent key contributors to the increase in System Renewal investment compared to the previous DSP.

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 5.4-14 summarizes the forecast system O&M spending over the forecast period.

Table 5.4-14: Forecast System O&M Expenditures

Category	Forecast ($ '000)				
	2027	2028	2029	2030	2031
System O&M	4,010	4,371	4,576	4,841	5,104

While it is hypothesized that System Renewal investments would avoid increases to system O&M costs, System Access and System Service investments are expected to contribute to increases in system O&M costs as they expand the asset base requiring maintenance. Given high customer growth rates driven by new development over the forecast period, InnPower's asset base is expected to increase significantly, which will further impact system O&M costs. Like many utilities, InnPower is also experiencing increases in supply chain, contractor, and labour costs, which are contributing to

higher System O&M expenditures. In addition, workforce growth required to meet customer needs adds further cost pressure. Collectively, these factors are expected to result in an overall increase in system O&M costs 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 optimization, prioritization and pacing of capital-related expenditures.

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 discuss how its application keeps 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 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, CYME 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 as well as load flow analysis and real-time short fault calculations throughout the organization. Currently since the GIS ARC map is retired, InnPower is moving to ARC GIS Pro and adopt the system to most recent

technology. InnPower also working with different vendors on Artificial Intelligent system to make sure the system will be compatible in future.

- **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 2022 to 2031 period, for net capital expenditures and underlying investment categories, both including and excluding the BATU and TS Projects, are shown in Figure 5.*4-20* and Figure 5.*4-21*, respectively.

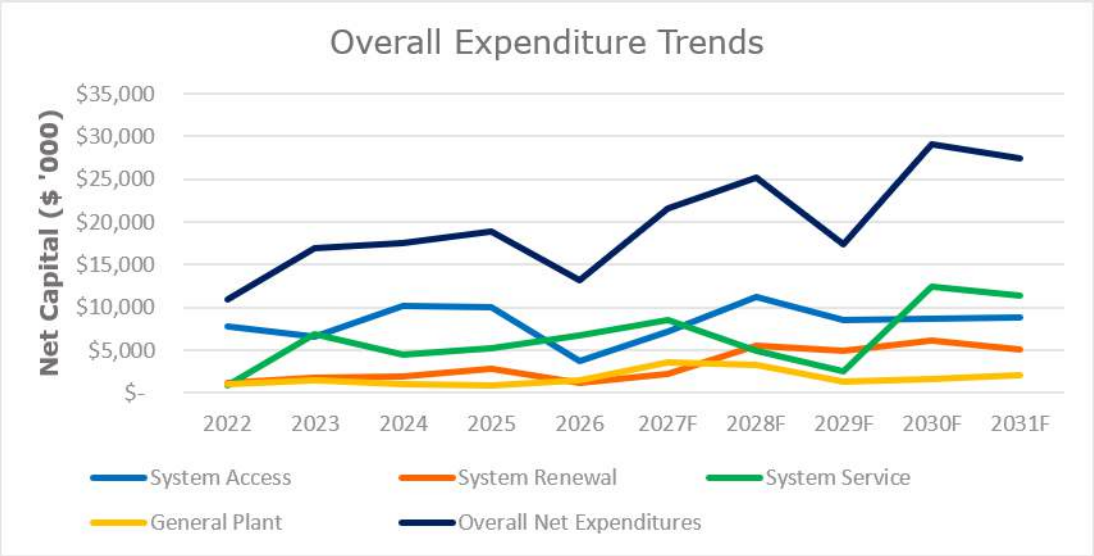

Figure 5.4-20: Overall Net Capital Expenditure Trends

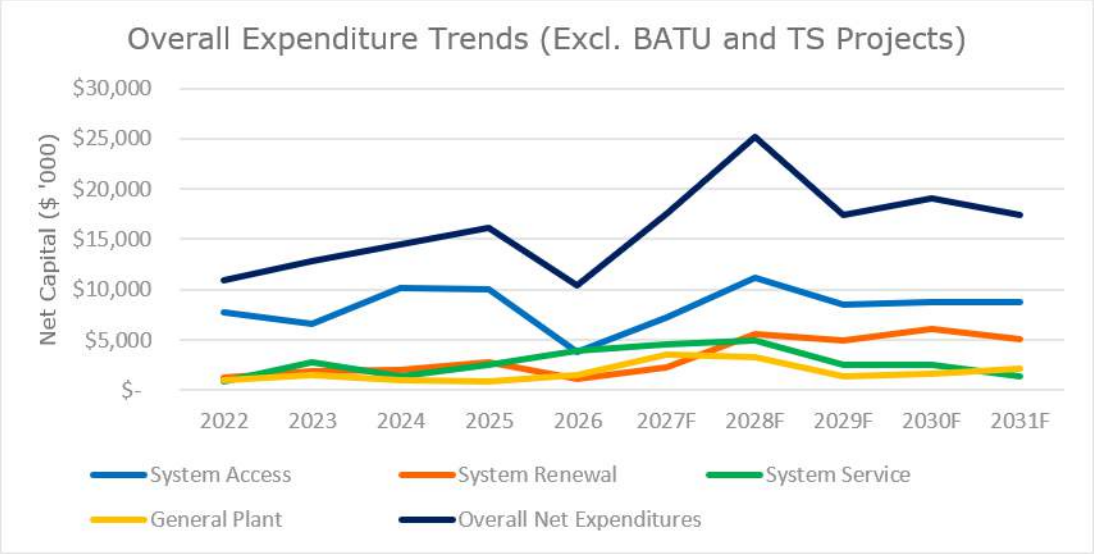

Figure 5.4-21: Overall Net Capital Expenditure Trends (Excl. BATU & TS Project)

When including the BATU and TS Project costs, InnPower's forecast net capital expenditures are expected to remain above historical expenditure levels over the forecast period, with year-over-year variability driven by the timing of major capital programs, customer growth requirements, and major

system investment projects. Overall net expenditures increase from approximately $10.9M in 2022 to approximately $29.9M in 2030. The higher expenditures in 2029 and 2030 are primarily attributable to the timing of major System Service investments associated with BATU and TS Projects.

When excluding the BATU and TS Project costs, InnPower's forecast net capital expenditures are expected to remain above historical expenditure levels over the forecast period, while exhibiting moderate year-over-year variability driven by the timing of major capital programs and customer growth requirements. Overall net expenditures increase from approximately $10.9M in 2022 to a peak of approximately $29M in 2030, before moderating in the later forecast years.

The reduction in expenditures in 2026 is primarily attributable to the timing and completion of certain System Access and System Renewal projects, while the increase beginning in 2027 reflects accelerated investments required to support customer growth, capacity requirements, and asset replacement needs across InnPower's service territory.

As detailed in Section 5.4.1.3, the forecast increase relative to historical expenditures is primarily driven by continued investments in System Access to accommodate known customer growth areas and system expansion requirements within InnPower's service territory. Increased investments in System Renewal are required to maintain and replace aging infrastructure and end-of-life equipment to ensure the continued delivery of safe and reliable electricity service. System Service expenditures are also forecast to increase over portions of the planning period to support system rehabilitation activities, operational requirements, and targeted capacity upgrades. In addition, General Plant investments are expected to support ongoing fleet, information technology, building, tools, and equipment upgrades necessary to efficiently serve 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 Asset Management objectives discussed in Section 5.3.1.1. These investments are intended to support the continued delivery of safe, reliable, and cost-effective electricity service, while accommodating forecast customer and load growth within 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 in Table 5.4-15 and Table 5.4-16. The level of detail filed by a distributor to support a given investment project or program should be proportional to the materiality of the investment.

Table 5.4-15: Proposed Capital Investments during Test Year - Projects over Materiality

Investment Category	Program/Project Name	Priority Score [1]	Status	2027 Planned Expenditure ($'000)
System Access	(IPCSA) 100% Recoverable [2]	n/a	Budgeted	0
System Access	(IPCSA) Subdivisions	n/a	Budgeted	5,751
System Access	(IPCSA02) Road Authority	n/a	Budgeted	2,924
System Access	(IPCSA05) Metering	n/a	Budgeted	536
System Renewal	(IPCSR01) Capital Trouble Calls and Emerging Projects	1,269.86	Budgeted	465
System Service	(IPCSS17) BATU	1,254.14	Budgeted	247
System Service	(IPCSS12) Station Rehab [3]	1,192.74	Budgeted	2,911
System Renewal	(IPCSR04) Reclosure Replacement Program	473.30	Budgeted	400
System Renewal	(IPCSR02) Transformer Replacement Program	457.62	Budgeted	247
General Plant	(IPCGP12) Fleet	405.4	Budgeted	845
System Service	(IPCSS24) Normal Open Point Switch Installation	404.83	Budgeted	158
System Renewal	(IPCSR06) Switchgear Replacement Program	373.23	Budgeted	280
System Renewal	(IPCSR03) Pole Replacement Program	335.64	Budgeted	418
System Renewal	(IPCSR05) Switch Replacement Program	181.90	Budgeted	257
General Plant	(IPCGP01) IT Hardware	166.31	Budgeted	418
General Plant	(IPCGP02) IT Software	166.31	Budgeted	1,488
System Service	(IPCSS08) Communication Improvement	64.91	Budgeted	106
General Plant	(IPCGP04) Building and Fixtures	27.17	Budgeted	295
System Renewal	(IPCSR07) Voltage Regulators	473.3	Budgeted	390
System Renewal	(IPCSR16) Sandy Cove Rear Lot Conversion	113.7	Budgeted	150
System Service	(IPCSS11) InnPower TS	1,254.1	Budgeted	Nil[26]
System Service	(IPCSS19) Voltage Conversion from 8.32kV to 27.6kV	252.7	Budgeted	1,500
General Plant	(IPCGP06) Engineering IT	166.3	Budgeted	321
General Plant	(IPCGP07) Measurement & Testing Equipment	166.3	Budgeted	190
Total Planned Expenditure for 2027 Test Year				**19,832**

[26] There is no net cost budgeted in the 2027 Test Year for the project IPCSS11 – InnPower TS. However, there is a significant cost of $20 Million spread over 2030 and 2031 which warrants the generation of a material investment narrative which will allow InnPower to also file an Incremental Capital Module (ICM) towards the end of their forecast period.

Table 5.4-16: 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	54.6	2.5	2.7	5	2.7	5	7.4	9	20.1	9	54.6	1,269.90
(IPCSS11) InnPower TS	9	54.6	7.5	2.7	9	54.6	7.5	7.4	9	54.6	5	20.1	1,254.10
(IPCSS17) BATU	9	54.6	7.5	2.7	9	54.6	7.5	7.4	9	54.6	5	20.1	1,254.10
(IPCSS12) Station Rehab	7.5	54.6	7.5	2.7	9	54.6	5	7.4	9	54.6	7.5	20.1	1,192.70
(IPCSR04) Reclosure Replacement Program	7.5	20.1	2.5	1	7.5	2.7	7.5	20.1	9	20.1	9	7.4	473.3
(IPCSR07) Voltage Regulators	7.5	20.1	2.5	1	7.5	2.7	7.5	20.1	9	20.1	9	7.4	473.3
(IPCSR02) Transformer Replacement Program	9	20.1	9	2.7	5	7.4	5	7.4	7.5	20.1	9	7.4	457.6
(IPCSS24) Normal Open Point Switch Installation	7.5	20.1	2.5	1	2.5	1	7.5	20.1	9	20.1	2.5	1	404.8
(IPCSR06) Switchgear Replacement Program	7.5	20.1	2.5	2.7	5	1	7.5	7.4	9	20.1	5	2.7	373.2
(IPCSR03) Pole Replacement Program	9	20.1	2.5	1	5	2.7	5	2.7	7.5	7.4	7.5	7.4	335.6
(IPCSS19) Voltage Conversion from 8.32kV to 27.6kV	5	3	5	3	9	20	7.5	7	9	20	5	3	252.7
(IPCGP12) Fleet	7.5	7.4	1	1	7.5	2.7	5	2.7	9	7.4	7.5	7.4	187.5
(IPCSR05) Switch Replacement Program	9	7.4	2.5	1	7.5	2.7	7.5	7.4	9	7.4	5	2.7	181.9
(IPCGP01) IT Hardware	5	7.4	7.5	7.4	7.5	7.4	5	2.7	7.5	7.4	2.5	1	166.3
(IPCGP02) IT Software	5	7.4	7.5	7.4	7.5	7.4	5	2.7	7.5	7.4	2.5	1	166.3
(IPCGP06) Engineering IT	5	7.4	7.5	7.4	7.5	7.4	5	2.7	7.5	7.4	2.5	1	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	
(IPCGP07) Measurement & Testing Equipment	5	7.4	7.5	7.4	7.5	7.4	5	2.7	7.5	7.4	2.5	1	166.3
(IPCSR16) Sandy Cove Rear Lot Conversion	5	3	2.5	1	2.5	1	5	3	9	7	5	7	113.7
(IPCSS08) Communication Improvement	2.5	1	7.5	2.7	2.5	1	7.5	2.7	5	2.7	7.5	2.7	64.9
(IPCGP04) Building & Fixtures	7.5	1	5	1	1	1	5	2.7	1	1	5	1	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.

APPENDIX A: MATERIAL INVESTMENT NARRATIVES

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSA – 100% 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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

InnPower distributes electricity to residential, commercial, and industrial customers through overhead and underground infrastructure. The projects within these programs 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 cost associated with this project is due to the Hewitt and Salem development expansion works, which are projected to be completed in 2029. The associated expansion work is fully funded by the developers through executed Offer to Connect (OTC) agreements and is therefore 100% recoverable. This includes major upstream expansion work required to bring capacity into a new area, where no individual customers will directly connect to the upstream assets at the time of construction. The upstream costs associated with this work are 100% funded by the Hewitt and Salem developer groups. Individual subdivisions will subsequently be serviced by these upstream assets, with an economic evaluation model completed for each subdivision to assess the incremental load and associated requirements at that time.

The timing of these expansion works is driven by developer requirements and customer connection needs; as a licensed distributor, InnPower is obligated to provide timely and non-discriminatory access to its distribution system. 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. Notably, significant growth is expected in Barrie. Growth is also present in the Innisfil area, though it is not as pronounced as in Barrie.

2. Timing

i. Start Date: The scope, timing, and schedule of the projects in this program are provided by customers.

ii. In-Service Date: 2027-2031

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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	3,494	7,297	3,686	9,389	15,729	10,375	5,381	1,235	0	0
Contributions	2,251	8,313	3,908	8,571	16,528	10,375	5,381	1,235	0	0
Capital (Net)	1,243	(1,016)	(221)	818	(799)	0	0	0	0	0

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

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

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

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. Over the 2022–2026 period, the program resulted in approximately $25,000 of net capital expenditures compared to approximately $39.6 million in gross capital expenditures, reflecting the high level of capital recovery associated with developer-driven work.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 improve 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 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

i. 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 benefit-cost 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.

i. Benefit-Cost 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.

ii. 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.

i. Substantially Exceeding Materiality Threshold: This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

5. Economic Growth

Where the applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project[1].

InnPower confirms that the investment is associated with ongoing residential and commercial development activity within its service territory. The need for this project is primarily driven by growth in the Hewitt and Salem areas, where new developments are progressing and resulting in increased demand for electricity infrastructure to support timely and reliable service connections.

The project enables the delivery of required distribution capacity to service these developments and therefore supports the orderly connection of new load. This is consistent with provincial planning objectives that encourage the provision of infrastructure to support growth and housing supply in designated growth areas. Further details regarding the projected growth outlook and associated economic benefits are provided in the Growth Outlook and Economic Benefits Assessment Report (see Exhibit 1-6).

[1] *Applicants may consult the Ontario Regulation made under the Special Economic Zones Act, 2025 for specific criteria related to the determination of long-term economic benefits for Ontario.*

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

InnPower distributes electricity to residential, commercial, and industrial customers through overhead and underground infrastructure. These projects, which are nondiscretionary (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 1,022 residential, industrial and commercial units in 2027.

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: 2027-2031

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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	6,851	7,588	13,353	12,196	3,181	10,045	11,766	7,161	7,161	7,161
Contributions	634	1,905	3,768	5,038	297	6,294	4,232	2,362	2,362	2,362
Capital (Net)	6,217	5,683	9,585	7,158	2,884	3,751	7,534	4,799	4,799	4,799

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

The elevated costs in 2024 are primarily attributable to an adjustment to align estimated expenditures with developer payments related to energizations that were not previously recorded at the actual date of energization. This adjustment reflects an early rebase of historical cost allocations.

The lower cost profile in 2026 reflects an estimated energization of five (5) subdivision developments comprising of a total of 755 residential units, compared to thirteen (13) developments comprising approximately 798 residential units and three commercial developments in 2027, resulting in reduced associated infrastructure and servicing expenditures in that year. The 2027 forecast is based on active developer connection requests, realistic construction and energization timelines, and is consistent with the assumptions used in the load forecast.

The increased costs in 2028 correspond to an estimated energization of fifteen (15) subdivision developments, representing a higher level of development activity and associated infrastructure requirements.

The cost profile for 2029–2031 is based on continuation of historical development trends, as no specific subdivision developments have been identified for these years at this time; values therefore reflect planning-level estimates.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

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

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs have been provided in Section A3. At the time of finalizing this material narrative, historical actual expenditures are available through 2025. The 2026 amounts reflect budgeted expenditures rather than actual results, which contributes to the lower capital and contribution amounts reported for that 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.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 expansion and renewal of infrastructure support customer growth, enables new customer connections, and improves the overall capacity and flexibility of InnPower's system. These investments also contribute to 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.

This program directly complies with InnPower's asset management objectives of meeting regulatory requirements and accommodating load growth.

i. Main Driver: Customer service requests for connections (both new and modification to existing)

ii. Secondary Drivers: Mandated Service Obligations

i. 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 benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

5. Economic Growth

Where the applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project[1].

This project will facilitate planned residential development within InnPower's service territory by providing the distribution infrastructure required to connect new customers. The residential developments associated with the project include supporting community infrastructure and commercial facilities, such as schools, retail establishments, and service-related businesses.

By enabling the connection of forecasted residential load and associated community services, the project will support growth and development within the communities served by InnPower. In addition, the construction of the proposed developments and related infrastructure will contribute to economic activity and employment during the development period.

The project is consistent with provincial objectives related to housing development and infrastructure planning by ensuring that adequate electricity infrastructure is available to accommodate forecast growth and support the development of complete communities. Further details regarding the projected growth outlook and associated economic benefits are provided in the Growth Outlook and Economic Benefits Assessment Report (see Exhibit 1-6).

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[1] Applicants may consult the Ontario Regulation made under the Special Economic Zones Act, 2025 for specific criteria related to the determination of long-term economic benefits for Ontario.

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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. Over the forecast period, InnPower is planning to complete the following key projects:

i. County Road 4 Widening - Phase 3: Project to take place between InnPower south limit and CR 89. Phase 3 relocation to occur from 2026 to 2027.

ii. County Road 4 Widening - Phase 4: Project to take place between InnServices building and 9th Line. Phase 4 relocation to occur in 2027.

iii. County Road 4 Widening - Phase 5: Project to take place in Stroud. Phase 5 relocation to occur from 2027 to 2028.

iv. County Road 4 Widening - Phase 6 and 7: Project to take place between InnServices building and CR 89. Phase 6 and 7 relocations to occur from 2028 to 2029.

v. County Road 53 Widening: Project to take place between County Road 21 and Barrie City Limit. Relocation to occur in 2026.

vi. County Road 27 Widening: Between County Road 21 and County Road 90. Relocation to occur from 2028 to 2029.

vii. County Road 54 and Line 6 Intersection Innisfil: Project to take place at the noted intersection. Relocation to occur in 2031.

2. Timing

i. Start Date: The scope, timing, and schedule of the projects in this program are provided by the Municipalities.

ii. In-Service Date: 2027-2031

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;
- Road authority approvals, and
- Changes in project scope.

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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	176	667	342	2,597	3,614	3,749	3,862	3,978	4,097	4,220
Contributions	75	360	35	1,278	1,049	825	850	875	901	928
Capital (Net)	101	308	306	1,320	2,565	2,924	3,012	3,102	3,196	3,291

Contributions are governed by the Public Service Works on Highways Act, R.S.O. 1990, c. P.49.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

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. Annual expenditures may vary due to the timing and scope of road authority projects, which are determined by the respective road authorities and may be advanced or deferred from year to year. InnPower develops its forecasts based on information provided by the road authorities and updates obtained through ongoing coordination activities. 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 Projects

Year	Project Completed
2023	Killarney Beach Road and Yonge Street intersection. This relocation is due to the County of Simcoe widening and improving the intersection.
2024	Killarney Beach Road and 20th Sideroad (join project between Town and developers)
2025	Yonge St South of Hwy 89 – Coordination work between Hydro One and InnPower to prepare for Yonge St Road widening Innisfil Beach Road from 10th Sdrd to Yonge St for road widening
2026	County Road 4 Widening - Phase 3

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	The relocation of the distribution system needs to be done in advance of the road work. InnPower crews cannot safely work at 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 benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates*

(long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.

This is not applicable.

5. Economic Growth

Where the applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project[1].

InnPower confirms that the investment supports broader economic growth within its service area. The project is aligned with coordinated County Road works that include complementary infrastructure upgrades such as water and wastewater servicing, road widening, and multi-use trail development. These coordinated works are intended to improve the servicing capacity and accessibility of designated development areas.

By enabling the timely provision of electricity infrastructure alongside other municipal servicing, the project supports the orderly development of lands identified for growth and facilitates conditions that allow residential and commercial development to proceed in accordance with municipal planning objectives. Further details regarding the projected growth outlook and associated economic benefits are provided in the Growth Outlook and Economic Benefits Assessment Report (see Exhibit 1-6).

[1] *Applicants may consult the Ontario Regulation made under the Special Economic Zones Act, 2025 for specific criteria related to the determination of long-term economic benefits for Ontario.*

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

InnPower owns and operates 24,675 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 forecast for this program is based on InnPower's historical annual metering expenditures, adjusted for inflation, projected new service connections, anticipated reactive replacements arising from meter failures or other unforeseen issues, and planned proactive replacement activities. Meter procurement also reflects expected service growth and the need to maintain an appropriate inventory to support ongoing operations. The activities falling within the scope of this program includes:

i. Installation of residential, including suite meters, and commercial meters at new service locations; InnPower is looking to purchase 1,000 new meters on average each year over the forecast period.

ii. Upgrade of wholesale metering installations for expanded service requirements;

iii. Between 2027 and 2031, approximately 17,000 of InnPower's meters will expire and need resealing. Replacement of failed metering, expired seals, and obsolete metering for residential, commercial, and multi-residential customers.

InnPower's metering requirements include both reactive and proactive replacement activity. Reactive replacements occur where meters fail verification testing or are otherwise no longer serviceable, based on historical experience and annual variability in meter condition. Proactive replacements are undertaken as part of a defined replacement program, including the ongoing replacement of approximately 1,600 Itron meters over a three-year cycle. This proactive program is temporary in nature, and once completed, proactive replacement activity is expected to decrease.

Metering costs increase over the forecast period due to a combination of inflation, growth in service requirements, and changes in the mix of metering equipment required. Unit costs vary depending on meter type and application. Standard residential and general

service meters average approximately $295 per unit, while larger service installations average approximately $500 per installation.

The 2027 test year also includes metering-related capital components beyond meters themselves, including equipment for larger service installations, communications components, and other miscellaneous metering materials required to support installation and system functionality. These additional components, combined with the mix of meter types and inflationary cost pressures, contribute to higher average program costs in 2027 relative to historical levels. 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: 2027 - 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: 2027-2031

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.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	215	827	30	329	315	536	673	663	748	689
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	215	827	30	329	315	536	673	663	748	689

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Metering services are ongoing annual expenditures. Historical costs are reflected in Section A3 above. In the previous five historical years, InnPower has purchased 7,923 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 2022-2026. 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
2022	651
2023	3070
2024	822
2025	1255
2026	2125

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

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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 2027-2031 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: 2027-2031

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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	526	554	895	1,381	266	465	479	493	508	523
Contributions	80	71	392	0	0	0	0	0	0	0
Capital (Net)	445	483	503	1,381	266	465	479	493	508	523

The overall program costs detailed above are inclusive of inflation, material, and labour charges.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs for the 2022-2026 period are reflected in Section A3 above. Historical costs have varied year over year in accordance with specific needs identified. The spike in 2025 was caused by the repair costs after a large ice storm. InnPower applied for a Z-Factor in the 2026 IRM and was approved a rate-rider to recover costs. 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 as part of Capital Trouble Calls program.

Table 2: Historical Capital Trouble Call Asset Replacements

Asset Class Description	2022	2023	2024	2025	2026*
Stations	9	0	0	0	0
Poles, Towers, Fixtures	14	8	70	47	6
Overhead Lines	123	1	60	1,050	0
UG Conduits	0	0	0	0	0
Underground Lines	0	0	0	0	0
Transformers	0	5	2	1	0
Padmount Transformers	0	3	0	3	1
OH Services	315	0	45	20	0
UG Services	117	0	106	196	0
Meters	0	0	0	0	0
Total	578	17	283	1,317	7

**As of June 2026*

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Assets that 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.
Customer Value	When failed assets are replaced with new assets, designed to latest engineering standards, InnPower anticipates an improvement in its customer reliability performance (although this is by no means guaranteed). 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 benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR02 – TRANSFORMER 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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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:

i. the condition as identified by the asset condition assessment (ACA) and annual inspections,

ii. identified safety issues,

iii. environmental concerns, and/or

iv. consistent and significant overloading of the transformer.

The ACA indicates that while the overall distribution transformer population is generally in good condition, a subset of assets have been identified in lower condition categories (see Appendix D of the DSP). Of the 2,195 pole mount transformers assessed, 175 were classified as Fair and 79 were classified as Poor. Of the 2,161 pad mount transformers assessed, 15 were classified as Fair, 4 were classified as Poor, and 1 was classified as Very Poor. These ACA results, together with ongoing inspection findings, safety considerations, environmental concerns, and loading requirements, are used to identify and prioritize transformer replacement candidates.

Recent operating experience has also demonstrated that transformer condition can deteriorate rapidly. Over the course of a single winter, four padmount transformers that had been assessed as being in Fair condition became leakers, requiring emergency replacement and resulting in unplanned outages. The costs associated with these emergency replacements are addressed under the Emerging Projects narrative. This experience demonstrates that, while asset condition assessments are a key input into replacement planning, transformer condition can change quickly and reinforces the need for ongoing inspection, condition monitoring, and proactive replacement of assets exhibiting deteriorating condition.

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 anticipates replacing fifteen (15) transformers annually; however, this figure is indicative and is

dependent on asset condition, as determined through ongoing inspections and asset health assessments, as well as the mix of overhead and underground units requiring replacement in a given year. Additional environmental remediation requirements may also influence annual replacement volumes.

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 2027 to 2031.

ii. In-Service Date: 2027-2031

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.
- seasonal construction constraints, including heavy winter and wet spring conditions, which may delay field execution and result in engineering, design, and material procurement activities being completed in advance of construction activities within the same program year.

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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	147	155	598	622	224	247	255	262	270	278
Contributions	12	16	101	30	0	0	0	0	0	0
Capital (Net)	135	139	497	591	224	247	255	262	270	278

The overall program costs detailed above are inclusive of inflation, material, and labour charges. Please note that supply chain costs were volatile in 2020 to 2023 due to shortages in transformers and therefore costs increased.

Although no transformer replacements were completed in 2026, expenditures were incurred for engineering, design, and material procurement associated with projects scheduled for construction later in the year.

The planned replacement of approximately 15 transformers annually represents a target level of proactive replacement based on asset condition and inspection results. Annual expenditures and unit volumes may vary depending on differences in transformer type, asset condition outcomes, and timing of field execution within the annual work program. In addition, a portion of transformer-related work may be completed through emergent or trouble call response rather than planned capital replacement, depending on the timing of asset deterioration and operational conditions. This may result in year-to-year variability in capital expenditures and can lead to apparent differences between historical unit counts and forecasted expenditure levels.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs are presented in Section A3 above. This project represents the continuation of InnPower's long-term annual transformer replacement program. Year-over-year variability in historical expenditures is primarily attributable to industry-wide supply chain constraints, including transformer shortages and above-normal inflationary pressures affecting material availability and pricing.

Notably, during the 2020 to 2023 period, transformer availability was significantly constrained, resulting in limited ability to procure units during that time. In response, InnPower updated its procurement approach and standards to enable participation in a USF-led purchasing group to improve access to transformer supply.

The elevated expenditures observed in 2024 and 2025 reflect a recovery period following these supply chain constraints, during which InnPower is addressing deferred replacement activity. This includes the replacement of leaking units and transformers exhibiting corrosion or condition deterioration that present increased reliability and public safety risk. As a result, replacement activity during this period reflects both ongoing annual replacements and the remediation of backlog resulting from prior procurement delays. 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
2022	5	5	10
2023	6	4	10
2024	5	8	13
2025	9	0	9

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

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 Driver*:*

   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 associated with insulating oil leaks or spills.

ii. Secondary Drivers*:* 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 revisit, 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. InnPower also incorporates operating experience into its asset management process to validate condition assessments and inform replacement priorities where field performance indicates changing asset condition. 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 D – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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. Benefit-Cost 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. InnPower's operating experience and asset condition assessments continue to demonstrate that transformer condition can change over time, and that a portion of assets identified for planned replacement may require earlier-than-expected intervention through operational response. This reinforces the importance of combining inspection results with field experience in prioritizing replacements.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

InnPower is participating in a collaborative procurement initiative led by the USF involving multiple utilities coordinating the procurement of distribution transformers. The initiative is intended to address ongoing supply chain constraints affecting transformer availability through coordinated purchasing, standardized specifications, and aggregated procurement volumes.

The objective of the initiative is to improve access to constrained manufacturing capacity, enhance procurement efficiency, and achieve potential improvements in delivery timelines and logistics through economies of scale.

Through participation in this initiative, InnPower has been able to secure access to transformer supply in 2023, where standalone procurement would have been significantly constrained due to market availability limitations. This supports the timely execution of capital replacement programs and reduces the risk of delays associated with transformer shortages.

This collaborative procurement approach is expected to benefit customers by improving supply chain resiliency, supporting timely asset replacement, and maintaining the reliability of electricity service.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR03 – POLE 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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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 (see Appendix D of the DSP), the poles that are in poor or very poor condition need to be replaced before they fail. The ACA identified that, of the 11,008 wood poles assessed, 1,817 poles were classified as Poor and 132 poles were classified as Very Poor, representing approximately 18% of the wood pole population. The remaining wood pole population consists of 2,538 poles classified as Very Good, 3,463 poles classified as Good, and 3,058 poles classified as Fair.

The poles in poor and 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. These ACA results, together with ongoing inspection and residual strength testing results, support the identification and prioritization of pole replacement candidates.

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. Actual annual replacements may vary depending on safety-driven requirements and asset condition outcomes and may exceed the planned average in circumstances where identified assets present elevated safety risk requiring timely replacement. 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 2024.

Figure 2: Example of cracking and creosote bleeding at the base of a pole that was identified during visual inspection in 2024.

2. TIMING

i. Start Date: This is an annual investment initiative to manage end-of-life assets.

ii. In-Service Date: 2027-2031

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 (municipalities/region/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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	709	595	761	423	283	418	431	444	457	471
Contributions	0	0	0	41	0	0	0	0	0	0
Capital (Net)	709	595	761	382	283	418	431	444	457	471

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

The 2026 expenditures include work completed during the year. Due to timing associated with updating completed work in InnPower's legacy ERP system, there may be a delay between project completion and the recording of completed assets, which can result in differences between annual expenditures and reported asset replacement counts.

Forecast expenditures reflect the anticipated mix of pole replacements based on the ACA and ongoing budget management. Unit replacement costs vary depending on the characteristics of the pole being replaced, including pole height and class. Accordingly, annual cost-per-pole comparisons based on historical averages are not necessarily representative of forecast costs.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs are presented in Section A3 above. This project is the continuation of InnPower's long-term annual pole replacement initiative. The historic cost is driven by the replacement of units based on inspection results. In the 2022 to 2024 period, a higher number of pole replacements were completed due to the ability to coordinate work with other planned capital activities and customer-initiated projects. This coordination allowed for more efficient execution of identified replacements, including a backlog of poles assessed as poor condition or presenting elevated safety risk from prior inspection cycles.

The 2026 budget reflects a lower level of planned expenditure as resources are reprioritized to accommodate voltage conversion work within the capital program. Notwithstanding this adjustment, pole replacement activities will continue to be guided by inspection results and asset condition to ensure ongoing system safety and reliability. The table below shows the number of poles replaced over period the historical.

Table 2: Historical Pole Replacements

Year	# of Poles Replaced
2022	59
2023	55
2024	48
2025	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

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

This is considered a medium investment priority overall and has a priority score of 335.64. 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 D – 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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", the Typical Useful Life of distribution wood poles is 45 years. Several 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 its 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 include:

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 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 D – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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. Benefit-Cost Analysis: Running the poles 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 annual replacement program is developed based on asset condition, safety risk, and inspection results, with the specific poles selected for replacement determined through the ACA and ongoing asset management practices. The benefits of like for like replacement include the ability to 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 2022-2025 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR04 – RECLOSER 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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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.

The ACA identified that the majority of InnPower's overhead line recloser population requires replacement consideration (see Appendix D of the DSP). Of the 31 overhead line reclosers assessed, 22 were classified as Very Poor, 1 was classified as Fair, 5 were classified as Good, and 3 were classified as Very Good. The Very Poor condition category represents approximately 71% of the overhead line recloser population. These ACA results, together with inspection findings and operational considerations, are used to identify and prioritize recloser replacement candidates. 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.

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).

2. Timing

i. Start Date: This is an annual investment initiative to manage end-of-life assets starting Jan 2027.

ii. In-Service Date: 2027-2031

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 (municipalities/region/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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	225	17	186	(26)	385	400	412	424	437	450
Contributions	0	0	0	0	194	200	206	212	218	225
Capital (Net)	225	17	186	(26)	191	200	206	212	218	225

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

The negative gross capital expenditure reported for 2025 reflects a reduction in Work in Progress (WIP). No costs were capitalized to this project during 2025, as previously accumulated WIP costs were transferred to other capital projects. The negative amount therefore reflects an accounting reallocation of costs rather than a reduction in program scope or recovery of previously incurred expenditures.

The increase in forecast expenditure in 2027 reflects a change in the mix of recloser assets being installed compared to the historical period. Historical installations include a combination of recloser technologies, including lower-cost manual reclose devices (e.g., Tripsaver units), whereas the 2027 forecast reflects the installation of three Viper reclosers, which are higher-functioning automated protection devices used for feeder sectionalizing and system protection.

As a result, historical unit costs are not directly comparable to forecast unit costs due to differences in asset type, functionality, and application.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

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. 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 Replacements

Year	# of Reclosers Replaced
2022	3
2023	1
2024	2
2025	0

The planned approach is to replace approximately 3 recloser units per year, based on asset condition and prioritization, until legacy oil-filled recloser units are fully decommissioned and removed from service.

It must be noted that the budget allocated towards this program only encompasses the replacement of distribution line reclosers. The forecast costs also account for increased inflation and increased material and labour costs.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

According to the Kinectrics Report "Asset Amortization Study for the Ontario Energy Board", Typical Useful Life of overhead reclosers is 40 years. 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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 replacement 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 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, and 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 D – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates*

(long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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 switches identified through the Asset Condition Assessment (ACA, see Appendix D of the DSP), inspections, and operational assessments as requiring replacement due to condition, functional obsolescence, operability limitations, or inability to interrupt load current. Investments in switch replacements and other renewal investments will mitigate safety and reliability risks associated with failure of these assets.

The ACA identified that switch assets are generally in good condition, with condition varying by switch type. Of the 51 overhead loadbreak switches assessed, 32 were classified as Very Good, 5 as Good, and 19 as Fair. Of the 493 overhead disconnect switches assessed, 492 were classified as Very Good and 1 was classified as Good. These ACA results, together with inspection findings and operational considerations, are used to identify and prioritize switch replacement candidates.

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 2027 and beyond will address units that have come back in the previous inspections with damaged components, safety issues, communication deficiencies, non-load break capabilities, operating issues during switching or planned work unable to be resolved by maintenance. 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 failed switch due to animal interference in 2025

2. TIMING

i. Start Date: This is an annual investment initiative to manage end-of-life assets starting in January 2027

ii. In-Service Date: 2027-2031

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/region/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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	32	378	42	266	37	257	265	273	281	289
Contributions	0	0	0	0	125	129	132	136	140	145
Capital (Net)	32	378	42	266	(88)	129	132	136	140	145

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

The historical expenditures are presented in Section A3 above. In 2022, replacement activity was lower due to supply chain constraints affecting the availability of gang-operated switches. As a result, replacement work that was deferred in 2022 was completed in 2023, resulting in higher expenditures in that year.

No gang-operated switches were replaced in 2022 or 2024. In 2022, expenditures under this budget portfolio included the replacement of multiple in-line switches. In 2024, only in-line switches were replaced where required due to inoperability, as no gang-operated switches were identified for replacement based on asset condition. In 2025, two gang-operated switches were replaced based on asset condition and identified failures. In 2025, two gang-operated switches were replaced based on asset condition and identified failures.

Table 2: Historical Gang-Operated Switch Replacements

Year	# of Gang-Operated Switches Replaced
2022	0*
2023	2
2024	0
2025	2

**Multiple in-line switches were replaced in 2022 and were included within this budget portfolio.*

Based on the historical budget amounts presented in Table 1, the average cost per gang-operated switch replacement was approximately $189k in 2023 and $133k in 2025. A comparable unit cost is not available for 2022 or 2024 because no gang-operated switches were replaced. Variations in unit costs reflect differences in the scope of work undertaken in each year. In addition to the switch itself, replacement work typically includes labour, vehicle costs and, where required based on asset condition, replacement of the supporting pole.

Planned activity in 2026 includes replacement of two gang-operated switches, consistent with ongoing asset health assessments and the continuation of the switch replacement program. The 2027 program also includes the replacement of two gang-operated switches. The 2027 budget reflects a 50% contribution from NRCan toward each replacement. Accordingly, the budgeted unit cost is not directly comparable to the historical unit costs, as it reflects external funding rather than a reduction in the underlying replacement cost.

The program from 2027 onward is intended to address units identified through inspections with damaged components, safety issues, communication deficiencies and non-load break capabilities. The target is to replace two gang-operated switches annually, together with any compromised in-line switches identified through InnPower's infrared inspection program.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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. 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 airbrake 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.
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 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 D – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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. Benefit-Cost 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. 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.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR06 – SWITCHGEAR 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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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. InnPower plans to replace pad-mounted switchgear identified through the Asset Condition Assessment (ACA, see Appendix D of the DSP), inspections, and operational assessments as requiring replacement to address condition, reliability, and safety risks.

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.

The ACA identified that pad-mounted switchgear assets are generally in good condition. Of the 121 units assessed, 49% were classified as Very Good and 45% as Good, resulting in approximately 94% of the population being in Good or Very Good condition. The remaining assets consisted of 7 units (6%) classified as Fair and 1 unit (1%) classified as Poor. These ACA results, together with inspection findings regarding enclosure condition, contamination, operability, and reliability performance, are used to identify and prioritize switchgear replacement candidates.

InnPower plans to replace switchgear units identified through the ACA and inspection program as requiring remediation or replacement, including assets exhibiting deteriorated condition, enclosure damage, internal contamination, or other reliability and safety concerns. 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 2025 Inspection with heavy corrosion and holes

Figure 2: Switchgear found during 2025 inspection with corrosion

2. TIMING

i. Start Date: 2027

ii. In-Service Date: 2027-2031

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/region/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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	7	0.2	0.2	1	340	280	286	291	320	326
Contributions	0	0	0	0	175	140	143	146	160	163
Capital (Net)	7	0.2	0.2	1	165	280	143	146	160	163

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

Historical expenditures from 2022 to 2024 are lower than forecast levels as switchgear replacement activity during this period was limited and undertaken using lower-cost or interim configurations, including reliance on existing inventory where available.

Forecast expenditures from 2027 onward reflect the transition to standardized Solid Dielectric (SD) switchgear configurations, which carry higher capital costs due to increased functionality, installation requirements, and equipment specification compared to earlier air-insulated configurations.

The nominal values of $0.2k in 2023 and 2024 represent minor residual capital adjustments associated with switchgear assets and do not reflect standalone replacement activity.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs are shown in Section A3 above. Switchgear replacements under this program have been undertaken on a condition-based basis, informed by field inspections and the ACA. Historical activity shows variability by year. The replacements completed to

date have been like-for-like (air-insulated for air-insulated) and utilized existing inventory where available.

Early replacements were completed on an ad hoc basis and reflect legacy air-insulated switchgear configurations, with available inventory utilized where feasible.

Table 2: Historical Switchgear Replacements

Year	# of Switchgears Replaced
2022	1
2023	0
2024	0
2025	2

The program starting in 2027 and onwards reflects a transition in replacement standard from legacy air-insulated switchgear to Solid Dielectric (SD) units, which are being adopted as the standard configuration except in emergency situations or where material lead times require interim solutions.

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

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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 (proactive): InnPower no longer purchases air insulated switchgears due to the limited functionality concerns.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 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.
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 contributes to reduced operational access during planned and unplanned switching activities, resulting in increased outage durations and restoration efforts. Damaged enclosures also present elevated safety risks for both the public and field personnel.

In addition to ACA inputs, operational experience has identified instances where switchgear becomes inaccessible or inoperable following winter conditions, including damage from snow clearing activities or vehicle contact. On average, approximately 3 to 4 units per year are identified through field inspections that cannot be safely operated and therefore require replacement outside of standard ACA-driven prioritization.

Replacement decisions also consider improvements in equipment design and configuration that enhance operational reliability and reduce exposure to environmental and service interruptions under field conditions. Additional reference information on prioritization factors and condition results is provided in Section 5.3.2.2.2 of the DSP and in Appendix D – Asset Condition Assessment Report of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR07 – VOLTAGE REGULATORS

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

The Voltage Regulator Program is intended to address voltage drop and power quality issues experienced by customers located at the far end of distribution feeders, particularly those operating at 8.32 kV. As load continues to grow, especially during peak summer periods, voltage levels at the end of these feeders can fall below acceptable limits, resulting in service quality concerns and customer complaints. These conditions have been confirmed through system monitoring (SCADA data) and customer feedback, indicating that the existing system is increasingly constrained in maintaining voltage within the standards.

The program involves the installation of voltage regulators on targeted feeders, with the initial phase focused on the LBF3 feeder in the northeast portion of InnPower's service territory, where three regulator units will be installed. These devices will actively control and stabilize voltage levels along the feeder, ensuring customers receive consistent power quality. The project represents a targeted, near-term solution that can be implemented more quickly than broader system upgrades.

Since InnPower continues to operate portions of its distribution system at 8.32 kV, power quality remains a concern at the ends of long feeder circuits. To address similar issues in the past, InnPower installed three voltage regulators on one of its long-run feeders, which successfully resolved identified power quality concerns and has provided reliable operation since being placed in service. Based on this experience, InnPower's engineering team has identified another location on an 8.32 kV feeder where power quality can be further improved. The proposed installation of three additional voltage regulators on the three-phase feeder will enhance voltage regulation, maintain acceptable service levels for customers at the end of the line, and support continued load growth within the area.

2. Timing

i. Start Date: 2027

ii. In-Service Date: 2027

iii. Key factors that may affect timing: The timing of the Voltage Regulator Program may be influenced primarily by equipment procurement and manufacturer lead times, as voltage regulators are specialized equipment with supply chain

dependencies. In addition, implementation depends on construction scheduling and resource availability, including coordination of installation activities on active feeders.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	-	-	-	-	-	390	-	-	-	-
Contributions	-	-	-	-	-	-	-	-	-	-
Capital (Net)	-	-	-	-	-	390	-	-	-	-

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

Not Applicable

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

InnPower has limited historical expenditure data specifically related to voltage regulator installations, as these projects are typically implemented on a targeted, needs-based basis rather than as recurring programs.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

The Voltage Regulator Program is considered a medium-to-high priority investment within the System Renewal category with the ranking of 473.3, as it directly addresses localized voltage performance issues impacting customers. While it does not represent a system-wide constraint like major capacity or station-related projects, it is prioritized above discretionary improvements due to its direct impact on customer service quality, including mitigation of voltage drop, reduction of complaints, and maintenance of regulatory voltage standards.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

i. Do-Nothing: Under a do-nothing scenario, InnPower would continue to operate the existing system without installing voltage regulators. While this option avoids upfront capital investment, it results in ongoing voltage drop issues, increased

customer complaints, and a continued risk of voltage levels falling outside acceptable limits, particularly during peak demand periods. This option does not address the underlying issue and leads to reduced service quality and potential regulatory non-compliance.

ii. Voltage Conversion / Feeder Offloading: Alternative system-level solutions such as voltage conversion or feeder offloading were considered. While these options could improve voltage performance, they require significantly higher capital investment, longer implementation timelines, and broader system upgrades. These solutions are not considered practical for addressing the immediate, localized voltage issues, as they are better suited for long-term system planning rather than near-term mitigation.

iii. Voltage Regulators (Recommended): The recommended solution is the installation of voltage regulators, which provides a targeted, cost-effective, and timely approach to maintaining voltage within acceptable limits. This option directly addresses the identified issue at a lower cost and can be implemented more quickly than system-wide alternatives. It ensures compliance with voltage standards, improves customer experience, and supports near-term load growth, making it the most efficient and practical solution for the identified need.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The investment improves efficiency by addressing voltage issues through a targeted solution rather than requiring broader system upgrades. The installation of voltage regulators provides a cost-effective approach to maintaining voltage levels, avoiding more capital-intensive alternatives such as feeder reconfiguration or voltage conversion in the near term.
Customer Value	Customer value is enhanced by maintaining voltage within acceptable limits, reducing complaints, and ensuring consistent power quality at the end of the feeder. This improves overall service quality and customer experience, particularly during peak demand periods.
Reliability	The program improves reliability by stabilizing voltage levels along the feeder, reducing the likelihood of voltage-related service issues and supporting more consistent system performance.
Safety	Safety is enhanced by maintaining system operation within acceptable voltage limits, reducing stress on equipment and minimizing the risk of equipment failure.

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*: Identify the main 'driver' ('trigger') of the project/program.*

The primary driver of the Voltage Regulator Program is related to maintaining acceptable voltage levels and power quality for customers. Portions of the distribution system, particularly long 8.32 kV feeders, experience voltage drop under increasing load conditions, especially during peak demand periods, resulting in potential non-compliance with voltage standards and customer complaints. Ther project is triggered by the need to stabilize voltage along affected feeders, ensure regulatory compliance, and maintain quality of service.

ii. Secondary Drivers: *Where applicable, identify any second drivers of the project/program.*

This is not applicable.

iii. Information Used to Justify the Investment: *Identity by reference to the distributor's asset management process, the source and nature of the information used to justify the investment.*

The Voltage Regulator Program is justified using information derived from InnPower's asset management and system planning processes, which integrate a range of operational and performance data. Key inputs include SCADA data and system loading information, which identified voltage drops and increased demand on affected feeders, particularly during peak summer periods. The engineering assessments and feeder reviews were used to evaluate voltage performance and confirm the need for targeted mitigation measures.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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: *Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change).*

The Voltage Regulator Program reflects accepted utility practice in reliability planning by implementing a targeted, condition-based solution to address voltage performance issues on constrained feeders. The installation of voltage regulators is a widely adopted industry approach to maintaining voltage within acceptable limits, particularly on long or heavily loaded feeders. Voltage regulators provide operational flexibility to manage fluctuations in load and seasonal demand, improving the system's ability to respond to changing conditions. This supports future grid requirements, including increasing electrification, distributed energy resource integration, and load growth.

ii. Benefit-Cost Analysis: *Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.*

A benefit-cost assessment compared the installation of voltage regulators against alternatives including a do-nothing approach and broader system upgrades such as voltage conversion or feeder reconfiguration. The do-nothing option avoids upfront capital investment but results in continued voltage issues, increased

customer complaints, and risk of non-compliance with voltage standards. Broader system solutions would address the issue but require significantly longer implementation timelines, making them less practical for addressing near-term, localized concerns. The installation of voltage regulators provides a targeted, cost-effective, and timely solution to maintain voltage within acceptable limits. The recommended option delivers immediate improvements in power quality and customer experience.

iii. Historical Investments & Outcomes Observed: *Show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments.*

InnPower has limited historical investment data specific to voltage regulator installations, as these projects are implemented on a targeted, needs-based basis rather than as part of a recurring program.

iv. Substantially Exceeding Materiality Threshold: *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).*

This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

The Voltage Regulator Program provides direct customer benefits by ensuring voltage levels remain within acceptable limits, resulting in improved power quality and more consistent electricity service, particularly for customers located at the end of long feeders. This reduces voltage-related issues and customer complaints, leading to an overall improved service experience and alignment with service quality standards. The program also enhances system reliability and operational responsiveness, as stabilized voltage levels reduce stress on equipment. The

program also provides a cost-effective, targeted solution that avoids more expensive system upgrades in the near term.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSR16 – SANDY COVE REAR LOT CONVERSION

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

The Sandy Cove Rear Lot Conversion Program addresses the infrastructure limitations associated with an aging rear lot distribution configuration. The existing system consists of direct-buried underground cables and transformers located behind residential properties, many of which lack proper foundations and are difficult to access. This configuration constrains InnPower's ability to perform routine maintenance and asset replacement activities.

The need for the project is driven by a combination of asset condition deterioration, accessibility challenges, and increasing reliability risks. While the transformers are generally in acceptable condition from a corrosion and oil leakage perspective due to the relatively low-traffic environment, the transformer population ranges in age from approximately 21 to 55 years, with an average age of approximately 39 to 45 years. Several units have been replaced over time in response to trouble calls, including failures associated with rust and oil leaks. The associated cable systems and foundations were originally installed in the early 1970s and are now beyond their typical serviceable life. These direct-buried cables represent some of InnPower's oldest underground cable assets, with an age profile of approximately 51 to 60 years. Due to the cable type, conventional cable injection techniques cannot be used to extend their service life. While InnPower does not perform condition testing on these cable assets and therefore relies primarily on age as an indicator of asset health, their advanced age, combined with the inability to rehabilitate them, increases the likelihood of asset failure. When failures occur, the rear lot configuration and associated accessibility constraints can result in extended outage durations and more complex restoration activities.

From an asset management perspective, the current configuration is unsustainable. Transformer replacements require specialized equipment such as cranes, leading to significantly higher unit replacement costs, while the direct-buried cable system cannot be rehabilitated or life-extended using conventional methods. Continued investment in like-for-like replacements within the existing rear lot configuration would not address the underlying accessibility limitations and would perpetuate higher replacement costs. In addition, access to rear lot equipment can be further constrained during periods of heavy snowfall, increasing the complexity of restoration activities. Continuing to operate under the current arrangement would necessitate ongoing reactive replacements at elevated costs, without addressing the underlying structural inefficiencies.

The scope of the program involves the conversion of the existing rear lot system to a front lot configuration, enabling improved access and standardization of infrastructure. This includes:

i. Replacement of aging underground cables and associated equipment

ii. Installation of transformers on accessible locations with appropriate foundations

iii. Relocate underground infrastructure to publicly accessible rights-of-way

Implementation is planned as a phased, multi-year program, reflecting the scale of civil construction, coordination requirements with property owners, and alignment with capital budget constraints. This structured approach allows InnPower to systematically modernize the infrastructure while managing costs and minimizing customer disruption.

Overall, the program represents a transition from a legacy system configuration toward a more accessible and maintainable distribution network. The program also helps with improved reliability, reduced lifecycle costs, and enhanced readiness for future load growth and system modernization requirements. InnPower is forecasting to spend $135k in the test year, but $14.35M across the 2027-2031 period.

2. Timing

i. Start Date: 2027

ii. In-Service Date: 2031

iii. Key factors that may affect timing: The timing of the Sandy Cove Rear Lot Conversion Program may be influenced by several factors, including the availability of capital budget approvals, which determine the ability to advance each phase of work, as well as the need to coordinate access with property owners given the involvement of private lands. In addition, the pace of implementation is dependent on construction sequencing and the availability of internal and external resources.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	-	-	-	-	-	150	3,800	3,080	4,200	3,100
Contributions	-	-	-	-	-	-	-	-	-	-
Capital (Net)	-	-	-	-	-	150	3,800	3,080	4,200	3,100

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

Not Applicable

5. Comparative Historical Expenditure

No direct historical unit cost data is available for the Sandy Cove Rear Lot Conversion Program. The previous phase completed approximately eight years ago under significantly different cost conditions.

6. Investment Priority

The Sandy Cove Rear Lot Conversion Program is considered a medium priority investment within the System Renewal category with the ranking of 113.7, reflecting InnPower's risk-based approach to capital planning. The project addresses evolving asset condition concerns and operational challenges associated with inaccessible rear lot infrastructure, resulting in a lower prioritization relative to higher-risk or non-discretionary investments across the system, but still warranting inclusion due to its long-term benefits.

The investment is paced as a phased, multi-year program to align with available funding and competing priorities. This approach allows InnPower to focus on higher-priority renewal and System Access requirements while continuing to advance this program to reduce lifecycle costs, improve accessibility, and enhance system reliability over time.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

i. Do Nothing: Under a do-nothing scenario, InnPower would continue operating and maintaining the existing rear lot configuration and replace assets only as failures occur. This option has the lowest short-term cost, but results in higher long-term expenditures due to continued reliance on reactive maintenance and the need for specialized equipment (e.g., crane access). It also leads to longer outage durations, increasing reliability risk and customer impact.

ii. Slower Pacing: A slower pacing alternative would defer portions of the program and spread the work over a longer time horizon. This approach reduces near-term capital requirements; however, it prolongs exposure to inefficient and aging infrastructure. InnPower would continue to incur elevated replacement and maintenance costs, along with increased risk of failures and outages.

iii. Proposed Pacing (Recommended): The recommended approach involves implementing the program over a phased, multi-year schedule aligned with capital planning cycles. This option balances cost, risk, and operational efficiency, allowing InnPower to systematically replace aging infrastructure while managing budget constraints. It reduces long-term costs by enabling standardized construction practices, improves accessibility for maintenance, and enhances system reliability. This approach provides the most prudent balance between affordability and long-term value and is therefore recommended.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (sections 4.3 and 4.4 in particular).

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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The program improves efficiency by replacing an inaccessible rear lot configuration with a standard front lot layout, significantly reducing the need for specialized equipment such as cranes and minimizing complex access requirements. This results in lower lifecycle costs, more efficient maintenance practices, and improved execution of future asset replacements.
Customer Value	The investment enhances customer value by improving service reliability and reducing outage duration. Customers benefit from faster restoration times, fewer prolonged interruptions, long-term cost stability and escalating reactive maintenance costs.
Reliability	The program improves system reliability by addressing aging underground cables and deteriorating transformers that are contributing to increasing fault activity. The conversion enables faster fault detection, improved access for repairs, and reduced outage duration.
Safety	The investment enhances safety by eliminating the need for complex and higher-risk access methods in rear lot locations. Improved accessibility reduces risks to crews during maintenance and replacement activities. The replacement of aging infrastructure reduces the likelihood of equipment-related safety incidents.

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: *Identify the main 'driver' ('trigger') of the project/program.*

The primary driver of the Program is asset accessibility and condition, which create increasing operational and reliability challenges. The existing rear lot configuration limits safe and efficient access to infrastructure, and the aging underground cables and transformers are beginning to experience deterioration, including faults, leaks, and corrosion. The program is triggered by the need to transition away from an inefficient and difficult-to-maintain system toward a more accessible and standardized configuration

ii. Secondary Drivers: *Where applicable, identify any second drivers of the project/program.*

The program further supports operational and cost efficiency objectives, as the existing rear lot configuration results in higher replacement costs and more complex maintenance due to limited access.

iii. Information Used to Justify the Investment: *Identity by reference to the distributor's asset management process, the source and nature of the information used to justify the investment.*

The Program is supported by information derived from InnPower's asset management process, system data and operational experience. Key inputs include asset condition assessments, field inspection records, and maintenance history, which identified deterioration in underground cables and transformers, that have experienced faults, oil leaks, and corrosion. In addition, outage data and fault trends were reviewed to confirm increasing reliability risks associated with the existing configuration. The engineering assessments and operational feedback have also highlighted the constraints of the rear lot configuration, including limited accessibility and high replacement costs.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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: *Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change).*

The program reflects accepted utility practice in distribution reliability planning by proactively addressing known limitations in system design and asset accessibility. The conversion from a rear lot to a front lot configuration enables improved access to infrastructure, which supports reduced outage duration and more efficient maintenance activities. By replacing aging underground cables and deteriorating transformers with up-to-date installations, the project strengthens the reliability of the distribution system. The program also aligns with industry best practices by transitioning away from legacy configurations towards a more sustainable system design. Improved accessibility and standardized infrastructure support future grid modernization initiatives and reduces vulnerability to external factors such as extreme weather events.

ii. Benefit-Cost Analysis: *Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.*

A benefit-cost assessment of the program compared the proposed phased approach against a do-nothing scenario and a slower pacing alternative. While the do-nothing option avoids upfront capital investment, it leads to higher long-term costs due to continued reliance on reactive maintenance, specialized access requirements, and increased outage durations. A slower pacing approach reduces near-term expenditures but prolongs exposure to aging and inaccessible infrastructure, resulting in higher cumulative lifecycle costs and delayed reliability improvements. The proposed phased implementation provides the most cost-effective outcome by balancing investment timing with risk reduction, lowering long-term maintenance and replacement costs, improving accessibility, and enhancing system reliability, and is therefore considered the preferred option.

iii. Historical Investments & Outcomes Observed: *Show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments.*

This is not applicable.

iv. Substantially Exceeding Materiality Threshold: *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).*

This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

The program provides several direct and long-term benefits to customers, primarily through improved reliability and reduced outage duration. By relocating infrastructure to more accessible front lot locations and replacing aging underground assets, the program enables faster restoration and minimizes the outage duration. The program also delivers long-term cost efficiency and service quality benefits. By enabling more efficient maintenance and reducing reliance on specialized equipment, the investment helps control future operating and capital costs, contributing to rate stability over time. Additionally, the modernization of infrastructure supports a more adaptable distribution system, better positioning InnPower to meet future customer needs.

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MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSS08 – COMMUNICATION IMPROVEMENTS

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

InnPower– have a Real Time communication set up with all their stations. Presently, InnPower has ten (10) Distribution stations and more than 50 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 rehealing 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 4 HUB NOKIA 800 switches which are at their end-of-life. The 12 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 has replaced two (2) switches and two (2) radios from 2024 to 2026. Future replacement activities will be completed based on asset condition and lifecycle requirements. InnPower plans to replace two (2) radios annually in 2027 and 2028, and three (3) radios annually from 2029 to 2031, with forecast costs adjusted for inflation.

The historical replacement cost per radio ranged from approximately $31.5K to $45K between 2024 and 2026. The forecast replacement cost per radio is approximately $53K in 2027 and 2028, increasing to approximately $60K from 2029 to 2031. The increase in forecast unit costs reflects inflationary impacts and expected changes in replacement costs over the forecast period. 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: 2027

ii. In-Service Date: 2027-2031

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;
- 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 (municipalities/region/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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	-	-	90	63	81	106	106	179	179	179
Contributions	-	-	0	0	0	0	0	0	0	0
Capital (Net)	-	-	90	63	81	106	106	179	179	179

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

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. From 2024-2026, InnPower has replaced two (2) switches and two (2) radios.

The spanning tree 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.

Table 2: Historical Communication Equipment Replacements

Year	# of Units Replaced
2022	0
2023	0
2024	2
2025	2

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

This investment has been scored at 64.91. Town of Innisfil utilities include the power 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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

InnPower considered the following options:

i. Do nothing and run to fail: 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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 3: 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

Primary Criteria for Evaluating Investments	Investment Alignment
	utilities can be notified ahead in time to eliminate any unforested issues that can cause interruptions or impact the quality of the 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 due to 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 benefit-cost 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. Benefit-Cost 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. 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSS11 – INNPOWER TS / TL PRE-WORKS

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

The New Transformer Station (TS) Project is required to address significant forecasted load growth within the Town of Innisfil and the southern portion of the City of Barrie, where existing supply infrastructure is approaching its practical capacity limits. The current reliance on the 44 kV system does not provide sufficient transformation capacity to support expected residential, commercial, industrial, and institutional development. Without additional infrastructure, InnPower would face capacity constraints that could limit its ability to connect new customers and maintain reliable service levels. The new TS Project was originally contemplated to follow on to Hydro One's Barrie Area Transmission Upgrade (BATU) project, which upgraded between Essa TS to the Barrie TS (EB-2018-0117).

While the original need for the project was driven by strong long-term load forecasts and significant planned development activity in the Town of Innisfil and southern Barrie, the project schedule has been updated since the previous Cost of Service application. Despite this schedule update, the underlying need for the project remains unchanged. Regional planning studies and updated load forecasts continue to confirm that additional transformation capacity will be required to support long-term load.

The project involves extending the 230 kV transmission system approximately 7 km into Innisfil and constructing a new 230/27.6 kV transformer station (Jones TS). The station will include two 83.3 MVA transformers, associated protection and control systems, and the establishment of eight new distribution feeders to serve future growth areas.

The need for this project has been identified through regional and local planning processes and is supported by:

i. InnPower load forecasts
ii. South Georgian Bay–Muskoka Needs Assessment (NA)
iii. Barrie/Innisfil Integrated Regional Resource Plan (IRRP)
iv. Local Advisory Committee (LAC) recommendations

This investment represents a long-term, system-level solution identified through regional planning processes, including the IESO and Hydro One studies, to ensure sufficient supply capacity, improve system reliability, and support ongoing development within InnPower's

service territory. The project will serve more than 22,000 customers and enable future electrification and integration of emerging technologies.

2. Timing

i. Start Date: January 2024

ii. In-Service Date: December 2030

iii. Key factors that may affect timing: The timing of the New Transformer Station (TS) Project may be influenced by several key factors, including regulatory approvals and coordination requirements with external agencies such as the Ontario Energy Board, Hydro One, and the IESO. Additionally, the project is dependent on transmission system integration and alignment, including completion of the 230 kV connection and associated routing studies.

Project timelines may also be impacted by supply chain constraints and long-lead equipment procurement, particularly for major components such as transformers and high-voltage equipment, as well as construction sequencing and resource availability for large-scale civil and electrical works. While mitigation measures such as early procurement planning are in place, these factors may affect the overall schedule and pacing of implementation.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	0	0	0	0	0	0	0	0	10,000	10,000
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	0	0	10,000	10,000

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

The forecast expenditures of $10 million in each of 2030 and 2031 reflect the estimated capital contribution that InnPower would be required to pay to the relevant transmitter in connection with the proposed transformer station. InnPower will update this forecast once a Leave to Construct application has been filed.

InnPower is not proposing to construct the transformer station itself or to seek treatment of the transformer station as a distribution asset for rate recovery. Rather, InnPower will continue to evaluate all available alternatives to meet system needs while minimizing impacts on local ratepayers.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

InnPower has not previously undertaken a project of similar scope and complexity to the new TS Project, as this represents the first Municipal Transformer Station (MTS) developed within its service territory.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

The new TS Project is considered a highest priority investment within the System Service category with the ranking of 1,254.1, as it addresses a fundamental capacity constraint at the supply level and is essential to maintaining system operability. InnPower's asset management framework prioritizes projects based on system need, risk to reliability, customer impact, and ability to enable growth. Within this framework, System Access investments remain non-discretionary, followed by System Service investments that address critical capacity and performance limitations. The TS Project ranks at the top of System Service priorities, as it directly enables the connection of new load and ensures continued reliable supply to existing customers.

The prioritization of this investment is also supported by its identification through the regional planning process that includes IESO and Hydro One, which confirmed the project as the preferred and required solution to meet long-term demand. The pacing of the project is determined by aligning major capital investments with forecasted demand thresholds, ensuring that capacity is delivered when required. Given the consequences of deferral, i.e. inability to accommodate growth and risk of system constraints, the TS Project is advanced as a critical, non-deferrable infrastructure investment within the capital plan

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

i. Do-Nothing: Under a do-nothing scenario, InnPower would continue to rely on the existing 44 kV supply without adding new transformation capacity. While this option avoids upfront capital investment, it results in significant long-term risks, including capacity shortfalls, inability to connect new customers, and increased likelihood of system overloading. This would ultimately lead to degraded reliability, service constraints, and potential delays in development, making it an infeasible option.

i. Connect to Existing Alectra Feeder: This option would involve connecting InnPower's system to an existing Alectra feeder. While it avoids new station construction, it provides limited capacity and scalability, making it unsuitable for accommodating the magnitude of forecasted load growth. It would ultimately

require additional upgrades in the future, leading to higher cumulative costs and operational constraints. Additionally, there is no available feeder capacity to connect InnPower to existing Alectra feeder.

ii. Expand Existing 44 kV Supply: Alternatives such as adding a new 44 kV feeder position at Barrie TS or operating existing 44 kV feeders beyond their planning limits were also considered. These options provide only incremental capacity improvements and introduce increased reliability and operational risks, as the system would be operating closer to or beyond design limits. While lower in initial cost, these solutions would not meet long-term demand and would result in repeated short-term investments and higher lifecycle costs.

iii. New Transformer Station (Recommended): The construction of a new 230/27.6 kV transformer station, along with extending the 230 kV transmission system, provides the most reliable, scalable, and cost-effective long-term solution. This option directly addresses capacity constraints, supports sustained growth, and avoids the need for multiple interim upgrades. Although this is high capital investment solution, it offers the lowest lifecycle cost and ensures InnPower can continue to connect new customers and maintain system reliability. The new TS Project is the preferred alternative by providing the best balance of cost, performance, and long-term value.

iv. Alternatives Considered by IESO: As part of the Barrie/Innisfil Integrated Regional Resource Plan (IRRP) conducted in May 2022, several alternatives were evaluated to address the projected supply capacity shortfall in the Innisfil area, where InnPower's demand is forecast to reach approximately 113 MW by 2029, exceeding the capability of the existing 44 kV supply from Barrie TS.

The following alternatives were considered:

- Connect InnPower to an existing Alectra feeder as an embedded customer; however, this option was eliminated because no spare feeder capacity was available.
- Add a third 44 kV feeder from Barrie TS at an estimated cost of approximately $20 million. While this would provide about 25 MW of additional capacity, it would only defer the constraint until around 2027 and would require further investment afterward.
- Overload the existing 44 kV feeders beyond normal operating capacity at an estimated cost of approximately $8 million, increasing capacity by about 20 MW in total. Similar to the previous option, this would only provide a short-term deferral of the capacity need.
- Develop non-wires alternatives (NWAs), including conservation and demand management (CDM), demand response, solar PV, and energy storage. Detailed analysis found these options were not cost-effective for addressing the

magnitude of the forecast need. In particular, an 81 MW battery storage facility was estimated to have a net present value cost of approximately $130 million.

The preferred and recommended solution was the construction of a new 230/27.6 kV transformer station connected through a 230 kV tap to the upgraded E28B/E29B transmission circuits. This option, estimated at approximately $48 million, provides a long-term supply solution, accommodates future growth in Innisfil, and was determined to be the most cost-effective alternative.

In summary, while several short-term wires and non-wires alternatives were assessed, the regional planning studies concluded that the new 230/27.6 kV transformer station is the only option capable of reliably and economically meeting InnPower's long-term load growth requirements.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

The New Transformer Station (TS) Project is not considered innovative in the sense of introducing new or unproven technologies; rather, it reflects established industry practice for addressing large-scale capacity constraints through supply-side infrastructure expansion. The project is being advanced as a conventional wires-based solution to address forecasted load growth and system capacity requirements.

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 the OEB's Filing Requirements for Electricity Transmission Applications (sections 4.3 and 4.4 in particular).

InnPower anticipates that the new TS Project will require a Leave to Construct (LTC) approval under Section 92 of the OEB Act, as it involves both the development of a new transformer station and a 7km upgrade of an existing transmission system to 230 kV. Consistent with the OEB's Filing Requirements for Electricity Transmission Applications (Chapter 4), InnPower, in coordination with Hydro One, has undertaken and/or initiated the key studies and assessments required to support the application.

From a need and alternatives assessment perspective (Section 4.3), the project has been identified as the preferred solution through regional and sub-regional planning processes, including the South Georgian Bay–Muskoka Needs Assessment Report and the Barrie/Innisfil Integrated Regional Resource Plan Report (Appendices B and A1). These studies confirmed that existing 44 kV supply infrastructure is insufficient to meet forecast load growth and that extending the 230 kV system with a new transformer station provides the most reliable and cost-effective long-term solution. Alternatives such as incremental upgrades to the existing system, connection to external feeders, or operating

beyond planning limits were evaluated and found to be either insufficient or not economically prudent.

With respect to project design, impacts, and consultation requirements (Section 4.4), the Class Environmental Assessment (EA) for Minor Transmission Facilities has been completed (Appendix A3), along with transmission routing studies and preliminary station design. In addition, an IESO System Impact Assessment (SIA) has been conducted to confirm system feasibility and integration requirements (see Appendices A4 and A5). The project includes approximately 7 km of 230 kV transmission line extension and the construction of a 230/27.6 kV transformer station with two 83.3 MVA transformers, along with associated infrastructure required to place the station into service.

InnPower and Hydro One are planning to submit the Section 92 Leave-to-Construct application by the end of 2026, following completion of detailed engineering, stakeholder engagement, and regulatory documentation. Procurement and construction activities are expected to proceed thereafter, with the project targeted for in-service in 2030.

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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The project improves efficiency by providing sufficient upstream capacity through a single, integrated solution, avoiding the need for multiple incremental upgrades to the existing system. By extending the 230 kV supply and adding transformation capacity, InnPower can meet long-term demand more efficiently and reduce future capital and operational costs.
Customer Value	Customer value is enhanced by ensuring that sufficient capacity is available to support new connections and continued growth. The project enables development across residential, commercial, industrial, and institutional sectors, while also supporting long-term rate stability by avoiding inefficient interim solutions.
Reliability	Reliability is significantly improved through increased transformation capacity and the creation of new feeder ties with the existing 27.6 kV network. This enhances system flexibility, allows for better load balancing, and provides backup supply options during outages, maintenance, or emergency conditions.
Safety	Safety is enhanced by reducing system loading constraints and avoiding operation of infrastructure near or beyond planning limits. The new station and associated infrastructure are

	designed to modern standards, improving overall system stability and reducing the risk of equipment failure and associated hazards.

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*: Identify the main 'driver' ('trigger') of the project/program.*

The primary driver of the new TS Project is the need to address significant forecasted load growth and associated capacity constraints within InnPower's service territory. Rapid population and economic growth in the Town of Innisfil and the southern portion of the City of Barrie are driving increased electricity demand across residential, commercial, industrial, and institutional sectors. The existing supply arrangement, supported by the 44 kV network, does not provide sufficient transformation capacity to meet this growth on a sustained basis.

System planning studies, including InnPower's load forecast and regional planning assessments, have identified that demand will exceed the capability of the existing system within the planning horizon, creating a risk of supply constraints, reduced system performance, and the inability to connect new customers. As such, the project is triggered by the need to maintain reliable service and enable continued development within the service territory.

System Service investments are prioritized where infrastructure limitations directly impact the ability to deliver electricity reliably and accommodate growth. The development of a new 230/27.6 kV transformer station addresses this requirement at the source level by providing adequate transformation capacity. The TS Project is a foundational investment for the continued operation and expansion of InnPower's distribution system.

ii. Secondary Drivers: *Where applicable, identify any second drivers of the project/program.*

The new TS Project is also supported by several secondary drivers related to operational flexibility and long-term system planning. The project will enhance system by creating new interconnections with the existing 27.6 kV distribution network, allowing for improved load transfer capability, backup supply during outages. The project is also driven by the need to support economic development and electrification, including growth in industrial, commercial, and institutional loads such as those in the Innisfil Heights Employment Area. The project supports

future grid modernization objectives, enabling the integration of distributed energy resources (DERs) and electric vehicle (EV) infrastructure.

iii. Information Used to Justify the Investment: *Identity by reference to the distributor's asset management process, the source and nature of the information used to justify the investment.*

The new TS Project is supported by information derived from InnPower's asset management and system planning processes, which incorporate a combination of load forecasting, engineering studies, and regional planning inputs. Key sources include InnPower's load forecast, which identified significant demand growth in the Town of Innisfil and the southern portion of the City of Barrie, indicating that the existing 44 kV supply system will not be sufficient to meet future requirements.

The need for the investment is also supported by regional and sub-regional planning studies, including the South Georgian Bay–Muskoka NA, the Barrie/Innisfil IRRP, and recommendations from the LAC. These studies identify the project as the preferred solution to address long-term capacity constraints. In addition, environmental and technical assessments, including the Class EA and the IESO SIA, have been completed to confirm the feasibility and system integration requirements of the project.

These inputs form a comprehensive, evidence-based justification, consistent with InnPower's asset management framework, confirming the need for a new transformer station to ensure reliable service delivery and accommodate future growth.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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: *Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change).*

The new TS Project demonstrates accepted utility practice in reliability planning by addressing upstream supply capacity constraints through a coordinated transmission and distribution solution. The development of a new 230/27.6 kV transformer station, combined with the extension of the 230 kV transmission system, aligns with standard industry approaches for ensuring sufficient capacity, and supporting reliable service under increasing load conditions. These types of

investments are considered essential when existing infrastructure is no longer capable of meeting forecasted demand, particularly in high-growth areas.

The project also supports the development of a more adaptable distribution system by introducing additional transformation capacity and enabling new feeder interconnections with the existing 27.6 kV network. This provides operational flexibility and allows for more effective load management during both normal and emergency conditions. The project supports future system needs, including increased electrification, integration of DERs, and evolving load patterns associated with EVs and economic development. The project ensures that the system remains capable of adapting to future challenges, including those related to extreme weather and long-term climate impacts.

ii. Benefit-Cost Analysis: *Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.*

A benefit-cost assessment considered for the new TS Project against several alternatives, including maintaining the existing system, connecting to neighbouring supply, and expanding the current 44 kV infrastructure. The do-nothing option avoids upfront costs but results in significant long-term risks, including capacity shortfalls and inability to connect new customers. Similarly, options such as connecting to an external feeder or expanding the existing 44 kV supply provide only limited, short-term capacity increases and would require repeated follow-on investments, resulting in higher cumulative lifecycle costs and increased operational risk.

In contrast, the construction of the new 230/27.6 kV transformer station provides the most efficient and sustainable long-term solution. While it involves a higher initial capital investment, it delivers adequate capacity, improved reliability, and long-term scalability. The project eliminates the need for incremental upgrades and reducing overall system costs over time. This approach ensures InnPower can meet future demand, maintain service quality, and support growth.

iii. Historical Investments & Outcomes Observed: *Show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments.*

InnPower has not undertaken a comparable transformer station project within its service territory, as this project represents the first Municipal Transformer Station to support bulk supply needs in the Town of Innisfil.

iv. Substantially Exceeding Materiality Threshold: *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).*

This is not applicable since the materiality threshold is not exceeded in the 2027 test year.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

The new TS Project provides significant benefits to customers by ensuring adequate system capacity to support current and future electricity demand across InnPower's service territory. By addressing supply constraints at the source, the project enables the connection of new residential, commercial, industrial, and institutional customers. The project supports ongoing growth and economic development. This ensures that customers can continue to receive reliable service without delays or limitations caused by insufficient infrastructure.

The project also improves system reliability and service quality through increased transformation capacity and the creation of feeder interconnections with the existing 27.6 kV network. These enhancements provide operational flexibility and backup supply during outages, resulting in fewer and shorter service interruptions for customers. The investment also supports long-term efficiency by enabling the system to accommodate future needs such as electrification, EV charging, and DERs.

5. Economic Growth

Where the applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project[1].

The new TS Project directly supports economic growth by enabling the connection of new residential, commercial, industrial, and institutional developments within InnPower's service territory, particularly in the Town of Innisfil and the southern portion of the City of Barrie. Load forecasts and regional planning studies, including the South Georgian Bay–Muskoka Needs Assessment Report and the Barrie/Innisfil Integrated Regional Resource Planning Report, identify significant planned development in these areas, such as the Innisfil Heights Employment Area, that will require additional capacity to proceed. The need for additional capacity is further supported by ongoing developer connection requests and growth identified through municipal secondary plans. InnPower is also developing a Master System Plan that will further assess forecasted growth and associated system requirements within its service territory. Further details regarding the projected growth outlook and associated economic benefits are provided in the Growth Outlook and Economic Benefits Assessment Report (see Exhibit 1-6).

[1] *Applicants may consult the Ontario Regulation made under the Special Economic Zones Act, 2025 for specific criteria related to the determination of long-term economic benefits for Ontario.*

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

InnPower replaces or rehabilitates its distribution station assets 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. In addition, each station is completely shut down and isolated on a four-year cycle so comprehensive electrical testing can be completed on each power transformer. This past year, the transformers at Sandy Cove DS were thoroughly tested. Station shutdowns also allow for the equipment to be refurbished. For example, at Sandy Cove, some defective gauges and minor leaks were repaired on each power transformer.

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. In 2026, InnPower will replace two power transformers, one each at Brian Wilson DS and Lefroy DS, with the old power transformers being refurbished and kept as spares.

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.

In 2024, the power transformer at Stroud DS was replaced with a recently refurbished transformer. The old transformer was sent for refurbishment to a third party and will be installed at Lefroy DS in June of this year. The old transformer at Lefroy DS will serve as one of the two system spares. Bob Deugo DS is currently undergoing a station expansion. A new 30 MVA transformer will be installed at Bob Deugo later this year to accommodate future load growth. The Bob Deugo station expansion project also includes the installation of two new reclosers and a puffer back switchgear. In addition, new foundations and a new ground grid will also be installed. Another major upgrade project scheduled for this year is the installation of a new 30 MVA transformer at Brian Wilson. It will replace an older 10 MVA transformer that will now serve as a system spare. The capacity expansions

at Bob Deugo DS and Brian Wilson DS will allow InnPower to service the forecasted increased load in the area in the coming years.

To support load growth in Innisfil area, InnPower also plans to expand another two stations in the 2029-2031 timeframe to accommodate the forecasted incremental load increase. The expansion of the Belle Ewart DS, which will be completed in 2028, is being driven by load growth in Innisfil and south Barrie, and is considered mostly recoverable by funding through capital contribution. The expansion of Sandy Cove DS is not expected to be recoverable through capital contribution. However, this will be assessed through the economic evaluations InnPower carries out to determine the actual contributions. Additionally, a power transformer will be replaced at Cedar Point DS in 2028.

InnPower also plans to perform station automation upgrades and high voltage termination upgrades at the other 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 2027 to 2031.

ii. In-Service Date: 2027-2031

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;
- 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 form.

InnPower has utilized coordination with third parties (municipalities/region/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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	241	230	979	719	1,428	2,516	6,211	404	404	404
Contributions	0	0	935	0	0	0	3,200	0	0	0
Capital (Net)	241	230	44	719	1,428	2,516	3,011	404	404	404

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

InnPower's capital contributions from third-party developments are governed through upstream expansion agreements with developers, which establish the framework for cost responsibility associated with new load connections and system expansion.

Once load requirements are confirmed and projects are scoped, applicable contribution requirements are determined in accordance with the terms of the relevant development agreement and applicable utility policies and standards.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs have been documented in Section A3 above. This project is a continuation of InnPower's long-term station rehabilitation initiative, with investments driven by inspection results. InnPower will continue to improve its system beyond the second expansion period (2023–2025) in accordance with its ACA results. These investments are required to meet short- and medium-term load growth requirements.

In 2022 and 2023, priority was awarded to the transformer rehabilitation program, which extended the useful life of the transformers and improved system reliability, rather than undertaking large-scale rehabilitation projects. As a result, capital expenditures were lower during this period.

The increase in gross costs in 2024 was primarily attributable to the expansion of Brian Wilson DS. This portion of the project was fully recoverable. In 2025, work continued on the non-recoverable portion of the Brian Wilson DS project, along with the ongoing transformer rehabilitation program and the initiation of the Belle Ewart DS expansion program.

In 2026, the non-recoverable portion of the Brian Wilson DS project was concluded. Additional work included the replacement of a transformer at Lefroy DS and the installation of four tap changer controllers, one each at Brian Wilson DS, Bob Deugo DS, Lefroy DS, and Stroud DS.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

InnPower considered several alternatives in order to meet the objectives of this program / project.

i. Do nothing and run to fail: 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 rehabs InnPower sent 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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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. 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 a 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 benefit-cost 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, IEEE and ANSI when applicable.

ii. Benefit-Cost 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.

iii. 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. InnPower has also invested in increased reclosure automation and animal guards at their stations. A reduction in response time and outages caused by animal contacts has been observed at stations where this program has been implemented.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates*

(long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.

This is not applicable.

5. Economic Growth

Where the applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project[1].

This project will enhance system reliability and increase available capacity within InnPower's distribution system, enabling the utility to accommodate anticipated load growth in the service area. This supports broader economic development objectives by ensuring adequate electrical infrastructure is in place to facilitate future residential, commercial, and industrial development.

The project is consistent with Ontario's economic growth objectives, which emphasize the importance of reliable and sufficient electricity infrastructure to support community development, housing supply, and regional economic expansion.

[1] *Applicants may consult the Ontario Regulation made under the Special Economic Zones Act, 2025 for specific criteria related to the determination of long-term economic benefits for Ontario.*

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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 Line	• 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 has been completed and energized in 2025. Based on HONI updated DCF and the cutover date of May 2026 the capital contribution from InnPower reduced tp $19.678M from $20.6M back in 2022. 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: 2022

ii. In-Service Date: 2025*

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).

**Project was completed in 2025. However, the true ups and payment is still outstanding.*

3. Historical and Future Capital Expenditures

Table 2: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	16	4,098	4,006	4,001	3,999	4,000	0	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	16	4,098	4,006	4,001	3,999	4,000	0	0	0	0

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

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

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

HONI is leading this project including development costs, so no comparative historical expenditure is necessary from InnPower.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 Subregion, 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 A1 and A2. 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 benefit-cost 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. Benefit-Cost 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 autotransformers and 115kV	End-of-life needs, capacity needs, and expandability are addressed.	Recommended

**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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

5. ECONOMIC GROWTH

Where the applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project[1].

The proposed project will support economic growth within InnPower's service territory by increasing distribution system capacity by approximately 36 MW, thereby enabling the connection of forecasted residential, commercial, and industrial load. The project is required to accommodate growth identified in InnPower's load forecast and municipal development plans, including planned development within the South Barrie lands and other commercial growth areas.

The additional capacity provided by the project will ensure that InnPower is able to meet anticipated future electricity demand and provide service to new customers as development proceeds within its service territory.

The project aligns with provincial objectives related to housing development, economic growth, and infrastructure readiness by facilitating the provision of electricity service to new residential communities, commercial establishments, and industrial facilities.

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[1] *Applicants may consult the Ontario Regulation made under the Special Economic Zones Act, 2025 for specific criteria related to the determination of long-term economic benefits for Ontario.*

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCSS19 – VOLTAGE CONVERSION

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

The Voltage Conversion program addresses multiple system-level challenges associated with operating portions of the distribution network at 8.32 kV, including voltage violations, increasing load demand, customer complaints, and reliability concerns. As load continues to grow within InnPower's service territory, the existing 8.32 kV infrastructure is approaching its practical operating limits, resulting in reduced capacity, voltage drop issues, and constraints on the ability to connect new customers or support upgrades. These conditions have been supported by SCADA data, customer feedback, and observed impacts from weather events, indicating that the existing system is no longer sufficient to meet current and future service requirements.

The scope of the program involves converting the affected feeder from 8.32 kV to the standard 27.6 kV system, which provides higher capacity and improved voltage performance. The work includes rebuilding the distribution line to accommodate the higher voltage, replacing or upgrading associated equipment, and integrating the feeder into the broader 27.6 kV system. The voltage conversion area contains a total of 511 poles ranging in age from 0 to 81 years and 122 transformers ranging from 0 to 67 years. While some assets have been replaced on an ad-hoc basis through storm response or trouble-call activities, most of the infrastructure in this area has not been subject to any systematic renewal or targeted investment program. The conversion is designed using standard construction practices, similar to pole line rebuilds, and will be implemented over a multi-year period aligned with capital planning and budget approvals. The Voltage conversion will begin in 2027 and be completed by 2032. InnPower is forecasting to spend $7.5M across the 2027-2031 period.

2. Timing

i. Start Date: 2026

ii. In-Service Date: 2032

iii. Key factors that may affect timing: The timing of the Voltage Conversion program may be affected by several factors, primarily capital budget approvals, which govern the ability to proceed with each phase of the project. In addition, implementation is dependent on construction sequencing and resource availability, given the need to coordinate line rebuild activities and equipment upgrades over multiple years.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	-	-	-	-	-	1,500	1,500	1,500	1,500	1,500
Contributions	-	-	-	-	-	-	-	-	-	-
Capital (Net)	-	-	-	-	-	1,500	1,500	1,500	1,500	1,500

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Direct historical unit cost data specific to voltage conversion projects is limited within InnPower's system, as this program represents a continuation and expansion of a relatively recent strategy to transition from 8.32 kV to 27.6 kV. However, comparable costs can be inferred from pole line rebuild projects, which utilize similar design, material, and construction approaches.

Based on past pole line rebuilds, unit costs for construction activities are generally consistent with standard distribution at the rate of $41,500 per pole. This unit rate represents an all-inclusive contractor cost and includes activities and materials such as hydro excavation, traffic control, pole installation, conductor installation, transformers, insulators, and associated overhead line equipment.

While the per-unit costs for this program are broadly aligned with typical pole line rebuild work, the overall project cost reflects the additional scope required for voltage conversion, including equipment upgrades and system reconfiguration. As a result, the program cost is higher than a like-for-like replacement project but remains consistent with industry practice for voltage uprating initiatives.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

The Voltage Conversion Program is considered a low-to-medium priority investment within the System Service category with the ranking of 252.7, reflecting its direct alignment with addressing active system performance issues and enabling future system

capacity. The program is triggered by identifiable concerns, including voltage violations, load growth, customer complaints, and reliability performance, which place increasing strain on the existing 8.32 kV infrastructure. Under InnPower's asset management and capital planning framework, projects that directly impact system capacity constraints and customer service levels are prioritized ahead of discretionary investments, as they are critical to maintaining system performance and supporting continued growth. The investment is paced over multiple years to align with capital constraints and construction sequencing, ensuring that the highest-impact upgrades are implemented first while maintaining a balanced and sustainable capital program.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

- Do-Nothing: Under a do-nothing scenario, InnPower would continue operating the existing 8.32 kV system and address issues through reactive maintenance and incremental upgrades. While this option avoids upfront capital investment, it results in increasing long-term costs due to ongoing voltage violations, growing system constraints, and rising customer complaints. It also leads to continued reliability challenges and limited capacity for load growth, making it an unsustainable option from both an operational and customer service perspective.
- New 8.32 kV Station: An alternative option considered was the construction of a new 8.32 kV supply station. While this approach would provide additional capacity, it would require significant capital investment, including land acquisition and installation of all associated station equipment, and would involve long lead times (approximately 3+ years) before benefits are realized. In addition, this option would still require continuing distribution system upgrades, such as pole line and transformer replacements, resulting in a higher overall cost solution with delayed improvements to system performance.
- Voltage Conversion (Recommended): The recommended approach involves converting the existing system from 8.32 kV to 27.6 kV. This option provides the most cost-effective and timely solution by leveraging existing infrastructure and enabling immediate progress on resolving voltage and capacity constraints. It improves reliability, supports load growth, and enhances long-term system efficiency without the need for new station construction. Compared to the alternatives, voltage conversion offers lower overall capital cost, faster implementation, and greater long-term flexibility.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The program improves efficiency by increasing system capacity through conversion to 27.6 kV, allowing more load to be served with fewer system upgrades. This reduces congestion on existing feeders and minimizes the need for incremental investments, resulting in more efficient use of infrastructure over the long term.
Customer Value	Customer value is enhanced through improved voltage performance, reduced complaints, and better service quality. The program supports reliable service and accommodates customer load growth, while also contributing to long-term rate stability by avoiding more costly alternatives such as new station construction.
Reliability	The investment improves reliability by resolving voltage violations and reducing system stress associated with operating at 8.32 kV. The upgraded system enables more stable operation, reduces the likelihood of outages, and improves overall feeder performance, resulting in fewer interruptions and faster restoration.
Safety	The conversion to a standardized system reduces operational risks for both field crews and customers.

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: *Identify the main 'driver' ('trigger') of the project/program.*

The primary driver of the Voltage Conversion Program to address system capacity constraints and voltage performance issues. Portions of the distribution system operating at 8.32 kV are experiencing voltage violations, increasing load demand, and customer complaints, indicating that the existing infrastructure is no longer sufficient to reliably support current and forecasted conditions. The project is triggered by the need to enhance system performance, improve voltage regulation, and increase feeder capacity. The conversion to 27.6 kV enables InnPower to maintain reliable service, accommodate continued load growth, and support long-term system operability.

ii. Secondary Drivers: *Where applicable, identify any second drivers of the project/program.*

The Voltage Conversion Program is also supported by System Renewal considerations related to asset condition, as some of the existing 8.32 kV infrastructure is aging and contribute to reduced performance and increased maintenance requirements. The program further supports operational efficiency and long-term planning objectives by standardizing the system to 27.6 kV

iii. Information Used to Justify the Investment: *Identity by reference to the distributor's asset management process, the source and nature of the information used to justify the investment.*

The Voltage Conversion Program is justified using information derived from InnPower's asset management and planning processes, which incorporate a combination of system data, engineering analysis, and operational inputs. Key sources of information include SCADA data, voltage monitoring records, and load flow analyses, which identified persistent voltage violations and capacity constraints on feeders operating at 8.32 kV. These system performance indicators were supported by complaint records, highlighting service quality concerns in affected areas. The load forecasts and growth projections, informed through planning studies, were used to assess future system requirements and confirm that the existing infrastructure would be unable to meet demand without significant upgrades.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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: *Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change).*

The Voltage Conversion Program reflects accepted utility practice in distribution planning by addressing identified system performance issues and transitioning toward a standardized distribution system. Converting from 8.32 kV to 27.6 kV improves voltage regulation, increases feeder capacity, and reduces system loading, as a result enhancing overall reliability and enabling faster restoration during outage events. This approach aligns with industry best practices for addressing voltage constraints and supporting sustained load growth within a distribution system. By enabling a higher-capacity and more flexible network, the conversion supports grid modernization initiatives, including the integration of DERs, electrification, and evolving customer demand patterns.

ii. Benefit-Cost Analysis: *Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.*

A benefit-cost assessment considered maintaining the existing 8.32 kV system, constructing a new 8.32 kV station, and proceeding with voltage conversion. The do-nothing option results in continued voltage issues, reliability concerns, and increasing long-term costs, while a new station requires significantly higher capital investment and longer timelines. In comparison, the voltage conversion provides the most cost-effective and timely solution by improving system capacity and performance using existing stations, delivering reliability benefits and supporting future growth while minimizing lifecycle costs.

iii. Historical Investments & Outcomes Observed: *Show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments.*

InnPower does not have direct historical investments specifically related to voltage conversion projects within its service territory. As a result, there is limited availability of past cost data or observed outcomes directly tied to this type of investment.

iv. Substantially Exceeding Materiality Threshold: *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).*

This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

The Voltage Conversion Program provides direct benefits to customers through improved reliability, voltage performance, and quality of service. By upgrading the system from 8.32 kV to 27.6 kV, the program reduces voltage violations and system constraints, resulting in fewer service issues and improved consistency in electricity delivery. Customers benefit from fewer outages and faster restoration times, leading to an overall improved service experience. The program also delivers long-term efficiency and cost benefits by enabling InnPower to accommodate load growth more effectively. The upgraded system is better positioned to support evolving customer needs, including increased electrification and DERs.

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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 473 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 two (2) units per year over the next 102 years. 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 through the installation of remotely operable tie points and open point switches between distribution feeders. The program supports broader distribution automation objectives and system flexibility.

ii. In-Service Date: 2027-2037 (initial implementation horizon)

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;
- delays to material shipment from vendors; and
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent form.

InnPower has utilized coordination with third parties (municipalities/region/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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	37	7	41	(5)	307	317	326	336	346	356
Contributions	0	0	0	0	154	158	163	168	173	178
Capital (Net)	37	7	41	(5)	154	158	163	168	173	178

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

This project at InnPower helps 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. Although no normal open point switches were installed in 2022-2023, the costs reflecting in Table 1 are due to design costs. The target is to replace two (2) normal open point location per year.

Table 2: Historical Switches Installed

Year	# of Switches Installed
2022	0
2023	0
2024	1
2025	0
2026	Plan for 2

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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.

ii. 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.

iii. 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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

This project modernizes InnPower's distribution system by adding automation to InnPower's switching assets. The 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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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, which 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.

Primary Criteria for Evaluating Investments	Investment Alignment
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.
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 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 benefit-cost 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. Benefit-Cost Analysis: InnPower believes that implementing this project strikes a balance between risk and cost. Two (2) 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 program, which began in 2023 and will span until 2037, will upgrade all normal open points in the InnPower distribution system by removing obsolete and manual single-phase in-line switches. Since 2023 the project costs have been primarily associated with design costs and not the replacement of switches. Due to the low number of replaced switches there are no historical outcome trends to observe.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP01 – IT HARDWARE

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

This capital program funds the ongoing investment required to maintain, refresh, and modernize InnPower's IT hardware assets. The IT environment is the operational backbone of a modern local distribution company - it enables 24/7 distribution operations, customer service delivery, field communications, OT supervisory connectivity, and compliance with the Ontario Cyber Security Standard and the Ontario Cyber Security Framework (OCSF). Without sustained, paced investment, InnPower cannot meet its licence obligations or maintain reliable service to customers.

Over the test period, this program is shaped by five converging pressures:

i. Concentrated lifecycle refresh: A significant volume of core network and end-user assets deployed during the previous rate period reaches end-of-life within the forecast window. Firewalls, switches, servers, UPS units, and end-user devices that were refreshed together will require replacement together, creating a heavier-than-average refresh profile relative to prior years.

ii. Regulatory cyber security obligations: The Ontario Cyber Security Standard came into force on October 1, 2024, as a licence condition under section 6.8.3 of the Distribution System Code. Version 3.0 of the Standard further requires reporting of cyber security incidents to the IESO. Periodic independent cyber security assessments based on the OCSF identify specific hardware investments required for compliance and continuous improvement.

iii. Organizational growth: InnPower's customer base, employee count, and connected-asset count continue to grow. This increases demand on the existing network, storage, and compute footprint, and expands the fleet of laptops, mobile devices, and phones that must be procured, secured, and managed.

iv. Resilience and continuity: Climate-driven weather events, supply chain volatility, and the evolving threat landscape require deeper redundancy in both connectivity and recovery capability than was contemplated in the previous submission.

v. Business process modernization: InnPower has established a combined Business Process Modernization and Project Manager role to lead a structured review of existing business processes over the coming years. Findings from this work are expected to identify targeted hardware investments that deliver efficiency, reliability, or customer service improvements. Any such investments are subject

to InnPower's standard prioritization and benefit-cost review and, where appropriate, will refine the composition of investments within the envelope set out in this narrative rather than expand it.

The 2027 investment profile reflects the timing of planned hardware refresh and infrastructure investments. In addition to the ongoing lifecycle replacement program described below, the test year includes increased investment in end-user computing equipment, including laptops and monitors that have reached end-of-life and require replacement. The test year also includes upgrades to network infrastructure to support cybersecurity requirements under the Ontario Cyber Security Framework (OCSF) and expanded network storage capacity to address growing storage requirements. The program is organized around the following workstreams:

Cyber security hardware (Ontario Cyber Security Standard / OCSF alignment)

i. Zero-trust architecture enablement, including next-generation proxy hardware, identity-aware inspection appliances, and segmentation gateways.

ii. Hardware to extend and enforce segregation between InnPower's IT and OT networks, reducing the cyber security risk profile of operational technology assets.

iii. Hardware investments arising from the recommendations of InnPower's independent cyber security assessment and any subsequent OEB-directed cyber audit activity.

iv. Security monitoring, logging, and detection appliances to support 24/7 visibility across the IT estate.

Core network and infrastructure refresh

i. Replacement of firewalls, switches, routers, and wireless infrastructure reaching end-of-life or end-of-support during the test period.

ii. Expansion of backup storage capacity to accommodate growing data volumes, longer retention horizons, and the requirements of the disaster recovery environment.

iii. Server and hyperconverged infrastructure refresh, including supporting UPS and environmental hardware.

iv. Continued investment in the real-time disaster recovery site established during the prior period.

Physical security at stations and facilities

i. Deployment of thermal cameras and enhanced physical access controls at outstations to improve perimeter security and early-warning monitoring of unmanned sites.

ii. Upgrades to physical security hardware at primary facilities consistent with OCSF control objectives.

End-user computing and resilience

i. Lifecycle replacement of laptops, monitors, peripherals, and meeting-room hardware on a five-year refresh cadence.

ii. New hardware to support ongoing employee growth and replacement hardware for unplanned failures.

iii. Dual-SIM mobile devices for critical staff to maintain connectivity during carrier outages or severe weather events.

iv. Ongoing maintenance of hotelling and collaboration hardware at InnPower's facilities to support the established hybrid work model.

v. Staff training and security awareness aligned to OCSF requirements.

Through this program InnPower will continue to deliver reliable service to its customers, reduce enterprise risk associated with end-of-life or non-compliant infrastructure, and meet its obligations under the Ontario Cyber Security Standard. The cost profile reflects a heavier-than-historical refresh year (2028) driven by the alignment of multiple major asset classes reaching end-of-life concurrently. InnPower will continue to assess, review, and adjust its investment plans as conditions evolve.

2. Timing

i. Start Date: The timing of replacements and additions is driven by InnPower's lifecycle program, regulatory obligations, identified cyber security needs, and employee growth, with investments beginning in the test year.

ii. In-Service Date: 2027-2031

iii. Key factors that may affect timing:

- Equipment failure or unplanned end-of-support announcements by vendors;
- New or amended regulatory requirements, including future versions of the Ontario Cyber Security Standard and OCSF;
- Findings from independent cyber security assessments and OEB-directed audit activity;
- Staff and contractor availability;
- Competing project priorities;
- Supply chain constraints and lead times for IT and network equipment;
- Outcomes of InnPower's business process modernization review; and
- Evolving cyber threat landscape.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	105	365	139	320	166	418	591	274	216	127
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	105	365	139	320	166	418	591	274	216	127

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs for the 2022-2026 period are reflected in Section A.3. Investments in IT hardware over the forecast period are expected to increase relative to the historical period for the following reasons:

i. A larger volume of assets - including core network devices, servers, and end-user devices deployed together in earlier cycles - reaches end-of-life within the forecast window;

ii. New hardware investments are required to meet the Ontario Cyber Security Standard and to address recommendations from InnPower's independent cyber security assessments;

iii. Growth in employees, customers, and connected assets has increased the size and complexity of the estate to be supported;

iv. Per-unit procurement costs for network and security hardware have continued to rise; and

v. Additional investment is required in physical security hardware at unmanned outstations and in resilience capabilities such as dual-SIM communications.

Accomplishments since the previous submission

Since the 2024 submission, InnPower has completed the items committed to in that filing and has delivered the following additional improvements to its IT hardware estate:

i. Stood up a full real-time disaster recovery site, providing active replication of critical systems and a tested failover capability;

ii. Completed the network switch, access point and infrastructure replacement program, refreshing end-of-life devices across primary facilities;

iii. Completed scheduled server refresh activities, including supporting compute and storage infrastructure;

iv. Completed HVAC upgrades supporting the primary server environment, improving thermal reliability and energy efficiency; and

v. Completed the IT hardware audit referenced in the prior submission; its findings inform the prioritization and pacing of investments described in this narrative.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

This investment was scored 166.31. Prioritization within the program is driven by (i) regulatory compliance obligations under the Ontario Cyber Security Standard, (ii) end-of-life and end-of-support status of in-service assets, (iii) findings from independent cyber security assessments, and (iv) business needs arising from organizational growth and the hybrid work environment. Investments that close compliance gaps or that address assets supporting critical operational or customer-facing services are prioritized ahead of discretionary upgrades.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

i. Do nothing: Deferring lifecycle refresh and cyber security investments would expose InnPower to (i) non-compliance with the Ontario Cyber Security Standard (ii) escalating cyber security risk as network and security hardware passes end-of-support, (iii) operational risk from running production workloads on unsupported infrastructure, and (iv) inability to recover from a major incident at the pace required by InnPower's stated recovery objectives. This option is not viable.

ii. Defer or stretch refresh cycles: Extending the refresh cadence beyond five years was considered. This would reduce near-term capital but would increase exposure to unsupported assets, raise the probability of unplanned outages, increase the volume of reactive replacement spending, and leave known cyber security gaps open for longer than is prudent. This option is not preferred.

iii. Carry out the proposed pacing of investments (preferred): This option allows InnPower to maintain its five-year lifecycle discipline, close cyber security gaps identified through independent assessment, complete the IT/OT segregation work, expand backup and storage capacity, and improve physical security at outstations - while spreading capital across the test period to avoid a single-year capital shock. This is the preferred option.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	InnPower treats its IT hardware as a strategic enterprise asset that underpins 24/7 operations. A disciplined lifecycle refresh program avoids the productivity, security, and capital-shock impacts of running assets past end-of-support. Standardized hardware platforms, virtualized server and storage environments, and centralized endpoint management reduce per-device total cost of ownership, simplify cyber security hardening, and shorten provisioning and recovery times. The recently established Business Process Modernization function will further refine where hardware investment delivers the greatest efficiency benefit, ensuring spend follows demonstrated process need rather than asset age alone. Where serviceable, replaced assets are redeployed into the disaster recovery environment or lower criticality use cases to extend value.
Customer Value	Customer-facing services - billing, outage communication, connection requests, and the customer portal - depend on the availability and integrity of InnPower's IT infrastructure. Modern, supported hardware combined with strong cyber security controls protects the confidentiality of customer data and the continuity of the services customers rely on. Investments in this program directly support InnPower's obligations under the Ontario Cyber Security Standard and the privacy principles embedded in the Ontario Cyber Security Framework (OCSF).
Reliability	Reliable distribution operations now depend as much on the IT and OT network stack as on the physical plant. The program funds end-of-life replacement of core network devices (firewalls, switches, routers), expansion of backup storage capacity, and the hardware required to sustain InnPower's real-time disaster recovery site. Network segmentation between IT and OT environments and the introduction of next-generation

Primary Criteria for Evaluating Investments	Investment Alignment
	proxy and inspection hardware reduce the blast radius of any single failure or compromise, improving overall system resilience.
Safety	The program contributes to public and worker safety through enhanced physical security at outstations (including thermal cameras and improved monitoring), reliable communications hardware for field staff, and dual-SIM capability for critical personnel to maintain connectivity during severe weather or carrier outages. Remote visibility into network and station infrastructure allows faster, safer response when conditions deteriorate.

** 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's IT hardware estate is a strategic asset that underpins safe, reliable, 24/7 distribution operations and the delivery of customer-facing services. Need for this investment arises from three principal drivers:

i. Primary driver - regulatory and lifecycle obligations: Compliance with the Ontario Cyber Security Standard is a condition of InnPower's distribution licence. Sustained hardware investment is required to (i) close gaps identified through independent OCSF-based cyber security assessments, (ii) maintain secure connectivity to the IESO Lighthouse service, (iii) support the segregation of IT and OT networks, and (iv) replace network, server, and end-user hardware as it reaches end-of-life on InnPower's established five-year refresh cycle.

ii. Secondary driver - growth and resilience: Continued growth in customers, employees, and connected assets increases demand on the existing IT estate and expands the device fleet. Investments in dual-SIM communications, backup storage capacity, the real-time disaster recovery site, and physical security at outstations strengthen InnPower's ability to maintain service during severe weather, supply chain disruption, or cyber incidents.

iii. Information used to justify the investment: InnPower maintains an asset register for IT hardware that records deployment date, expected end-of-life, and current condition. The results of the completed IT hardware audit referenced in the previous submission, together with the findings of independent cyber security assessments performed against the OCSF, are used to refine the prioritization and pacing of investments. InnPower also monitors guidance from the OEB, IESO, and the Canadian Centre for Cyber Security to identify emerging requirements.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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 follows industry-standard practice in managing IT hardware on a five-year lifecycle and in aligning its cyber security program with the Ontario Cyber Security Framework (which itself is based on the NIST Cyber Security Framework). Additions, replacements, and upgrades comply with InnPower's internal standards, the Ontario Cyber Security Standard, and InnPower's evolving operational needs. InnPower's recently established Business Process Modernization and Project Manager function provides additional governance over hardware investment by ensuring that purchases - whether driven by lifecycle, compliance, or process improvement - are tested against efficiency and reliability outcomes before proceeding. Replaced hardware is redeployed for disaster recovery or other non-critical use where practical.

ii. Benefit-cost analysis: Cost analysis is performed for all hardware purchases in accordance with InnPower's corporate purchasing policies. Standardization of platforms, consolidation onto virtualized and hyperconverged infrastructure, and redeployment of serviceable assets into the disaster recovery environment are used to extract additional value from the investment envelope.

iii. Historical investments and outcomes observed: Historical costs are reflected in Section A.3. Investments made over the historical period have supported uninterrupted 24/7 operations, enabled a smooth transition to and sustainment of the hybrid work environment, delivered a real-time disaster recovery site, completed the switch and server refresh programs committed to in the previous submission, and minimized the operational impact of cyber incidents observed across the broader sector.

iv. Substantially exceeding materiality threshold: This is not applicable.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP02 – IT SOFTWARE

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

This capital program funds the ongoing investment required to maintain, refresh, and modernize InnPower's IT software portfolio. Software is the primary tool through which InnPower delivers customer service, manages its distribution network, operates its back-office functions, and complies with regulatory obligations – including the Ontario Cyber Security Standard, which came into force as a licence condition on October 1, 2024, under section 6.8.3 of the Distribution System Code. The portfolio includes the Customer Information System (CIS), Enterprise Resource Planning (ERP), Workforce Management and CMMS platforms, the customer portal, financial systems, human resources software, cyber security tooling, the corporate intranet, and the supporting Microsoft platform.

Over the test period, the program reflects three concurrent objectives:

i. Replace and modernize core platforms that are approaching end-of-life, end-of-support, or functional obsolescence;

ii. Strengthen the cyber security posture in line with the Ontario Cyber Security Framework (OCSF) and the findings of independent assessments; and

iii. Modernize business processes through targeted automation and platform-led improvement, governed by InnPower's newly established Business Process Modernization function.

The 2027 investment profile reflects the timing of several planned software initiatives that are required to support these objectives. In addition to major platform modernization activities described below, the test year includes investments in Software-as-a-Service (SaaS) solutions for HR case management and corporate training, software required to advance InnPower's cybersecurity initiatives in accordance with the Ontario Cyber Security Framework, and increased subscription and licensing costs associated with annual vendor renewals, inflationary pricing adjustments, and additional software licences required to support new full-time equivalent (FTE) positions. These investments are planned for 2027 to support the implementation of InnPower's modernization and cybersecurity program during the test year, rather than being deferred to later years. The program is organized around the following workstreams.

Core platform modernization

i. Customer Information System (CIS) replacement
InnPower's current CIS is the NorthStar Utilities platform, which serves as the system of record for customer accounts, billing, and meter data. In practice, it has become inefficient and difficult to operate, provides limited access to usable data for reporting and planning, and offers constrained support for modern digital customer-service expectations. The system is approaching the limits of its supportability and practical functional capability relative to InnPower's current operating needs and customer expectations. Deferring replacement would extend the period during which core billing and customer processes rely on an aging platform with constrained data and integration capability.

The program therefore funds the replacement of the CIS with a modern platform that supports flexible rate structures, richer customer self-service, and integration with field and back-office systems. InnPower is conducting a structured competitive procurement process to select the CIS solution, including requirements definition, market assessment, vendor engagement, and evaluation of functional fit, implementation approach, vendor experience, cybersecurity posture, and total cost of ownership over the expected life of the system. The preferred CIS vendor will be the one that best meets InnPower's requirements at the lowest reasonable lifecycle cost, not simply the incumbent or lowest initial purchase price. At the time of filing, the CIS project is in the planning and evaluation stage, with implementation activities expected to commence in the test year and a go-live aligned with the 2027–2031 in-service window.

ii. Enterprise Resource Planning (ERP): InnPower's current ERP platform is Microsoft Great Plains (Dynamics GP). Microsoft has announced that product support and updates for Dynamics GP will end on December 31, 2029, with security updates ending on April 30, 2031. Industry guidance recommends that organizations plan and execute ERP migration well in advance of end-of-support dates in order to avoid compressed implementation timelines and the risks associated with running unsupported software. For a regulated electricity distributor, continued dependence on an ERP platform that is approaching its support horizon creates risk in relation to regulatory and tax updates, vendor responsiveness, cybersecurity, and long-term maintainability.

Beyond lifecycle risk, InnPower's current ERP environment does not adequately support the automation of financial and business processes; many workflows rely on spreadsheets, email, manual re-keying, and other non-integrated steps. A modern ERP is foundational to automating procurement, payables, approvals, reporting, labour costing, and other core administrative processes, and to providing a more reliable control environment for financial management and regulatory reporting.
ERP modernization is required to support current financial, procurement, and reporting needs and to integrate cleanly with the modernized CIS. InnPower is evaluating whether to align or combine CIS and ERP replacements where doing so improves data integrity, reduces integration cost, and avoids duplicated

implementation effort. The decision will be made on the basis of total cost of ownership and benefit-cost analysis, considering licence, implementation, integration, support, and lifecycle risk costs over the life of the platforms. The ERP project is currently in the requirements and options-evaluation stage. Implementation is planned to begin in the test year, in coordination with CIS, with in-service timing aligned to the 2027–2031 window.

iii. Workforce Management and CMMS Modernization: InnPower does not currently operate with a robust, modern CMMS and workforce management platform. Existing workforce and maintenance management capability relies on a patchwork of tools, including mCare, a NorthStar-related mobile workforce product for which vendor support ended as of March 31, 2026. The mCare platform is frequently broken, resulting in staff resorting to workarounds such as email, text messaging, and manual interventions to manage work orders and field activity. Guidance on obsolete and unsupported products notes that continued reliance on unsupported software increases security, operational, and compliance risk because such products no longer receive patches, bug fixes, or vendor support.

   The program funds the replacement of the existing workforce management and maintenance management capability with a modern platform that supports asset-aware work planning, mobile field execution, and structured capture of asset condition data to inform future planning cycles. As part of this process, InnPower obtained a quote for the vendor's proposed replacement platform, ServiceLink. The quote included $60,375 in licence fees for up to 15 users, $8,400 in additional licence fees for five more users, $11,550 for additional services, annual fees of $25,937, and one-time implementation costs of $100,000. Given the significant cost of both the current NorthStar/mCare environment and the proposed upgrade path within the same vendor family, InnPower is undertaking a broader project analysis and competitive procurement to ensure that the selected solution is chosen on the basis of functional fit and lowest reasonable lifecycle cost, rather than vendor continuity alone.
   The workforce management and CMMS project is in the requirements and alternatives-assessment stage. Implementation activities are planned to commence within the test year, with in-service timing coordinated with the CIS and ERP modernization so that asset management and field work processes are supported by a modern, integrated platform during the 2027–2031 period.

iv. Time-to-payroll solution: InnPower's current time capture and payroll workflow is highly manual, requiring staff to enter and re-key time data across multiple systems and spreadsheets. This creates avoidable administrative burden and increases the risk of payroll error, inaccurate labour costing, weak audit trail, and misallocation of time between operating and capital activities. In a regulated environment where labour costs affect both OM&A and capitalization, time and payroll processes should be supported by accurate, auditable, and efficient systems.olix365+2

   The program funds the replacement of the current time capture and payroll workflow with an integrated solution that reduces manual re-keying, improves

accuracy, and supports compliance reporting. InnPower is assessing time-to-payroll solutions through the same disciplined procurement lens applied to the broader modernization program, including evaluation of functionality, integration with ERP and workforce management systems, implementation effort, vendor support, and lifecycle cost. The time-to-payroll project is in planning and solution-assessment, with implementation planned to begin during the test year and in-service timing coordinated with ERP so that labour costing, payroll, and capitalization processes are stabilized within the 2027–2031 window.

Cyber security and operational resilience

i. Endpoint detection and response, security information and event management (SIEM), and identity and access management software aligned to the OCSF maturity targets.

ii. Software supporting segregation of IT and OT networks, including SCADA isolation capability and software-defined segmentation.

iii. Vulnerability management, patching, and configuration management software to support the continuous-improvement requirements of the Ontario Cyber Security Standard.

iv. Privacy and data protection tooling consistent with the privacy principles embedded in the OCSF.

v. Security software arising from the recommendations of InnPower's independent cyber security assessments.

Physical security and facilities software

i. Implementation of a Visitor Management Program, providing structured logging, badging, and screening of visitors at InnPower facilities. This complements the physical security hardware investments described in IPCGP01 (IT Hardware) and supports OCSF control objectives related to physical and environmental security.

Process modernization and productivity

i. Automation of finance processes, including electronic approvals, expense and mileage management, and timekeeping workflows, reducing manual effort and accelerating cycle times.

ii. Modernization of staff onboarding, including identity provisioning, access requests, equipment assignment, and required training - reducing time-to-productivity for new hires and tightening access control discipline.

iii. Targeted software investments identified through the Business Process Modernization function's review of existing business processes. Any such investments are subject to InnPower's standard prioritization and benefit-cost review and, where appropriate, will refine the composition of investments within the envelope set out in this narrative rather than expand it.

Evaluation and adoption of AI technologies

Over the test period, InnPower will evaluate and selectively adopt AI capabilities where they can be shown to deliver measurable efficiency, customer service, or reliability benefits. Initial focus areas include AI-assisted productivity tools for back-office staff, AI-supported analysis of CMMS and operational data to inform maintenance planning, and AI-assisted customer service workflows. All AI adoption is subject to InnPower's standard benefit-cost review, privacy and security review under the OCSF, and a pilot-before-scale approach.

Ongoing sustainment

i. Subscription and licensing costs for the Microsoft platform and other core productivity software, reflecting the sector-wide shift from perpetual licensing to subscription-based commercial models.

ii. Lifecycle upgrades, patches, and version refreshes for end-user and network software on InnPower's three-year refresh cycle, where vendor lifecycle terms permit.

iii. Integration software required to maintain data consistency across modernized and legacy platforms during the transition period.

Through this program, InnPower will replace platforms that have reached the limits of their supportability, strengthen its cyber security posture against rising sector threats, comply with the Ontario Cyber Security Standard, and unlock efficiency through disciplined process modernization. The cost profile reflects a heavier-than-historical year in 2027 driven primarily by the CIS / ERP modernization, with subsequent years returning to typical sustaining levels.

2. TIMING

i. Start Date: The timing of replacements and additions is driven by InnPower's lifecycle program, regulatory obligations, identified cyber security needs, business process modernization outcomes, and employee growth, with investments beginning in the test year. For the four core platforms (CIS, ERP, Workforce Management/CMMS, and time-to-payroll), the timing also reflects:

- The announced end-of-support horizon for Microsoft Great Plains (Dynamics GP) in 2029, with security updates ending in 2031.
- The cessation of vendor support for the mCare workforce management product as of March 31, 2026.
- The lead time required to conduct competitive procurement, complete benefit-cost and total-cost-of-ownership analysis, configure systems, migrate data, and implement change management in a prudent manner.

ii. Key factors that may affect timing:

- End-of-life or end-of-support announcements by software vendors;

- New or amended regulatory requirements, including future versions of the Ontario Cyber Security Standard and OCSF;
- Findings from independent cyber security assessments and OEB-directed audit activity;
- Availability and maturity of vendor solutions, particularly for CIS, ERP, and Workforce Management platforms;
- Staff and contractor availability for implementation and change management;
- Outcomes of InnPower's business process modernization review; and
- Evolving cyber threat landscape.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	85	98	47	145	394	1,488	445	222	205	215
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	85	98	47	145	394	1,488	445	222	205	215

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

The increase in 2027 is primarily attributable to a planned contribution toward the CIS/ERP modernization initiative, resulting in a heavier-than-historical expenditure year. Expenditures are forecast to decline in subsequent years as project-related spending is completed and investment levels return to typical sustaining levels.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Because the software portfolio comprises a diverse mix of applications with different licensing models, lifecycles, and replacement triggers, per-unit comparative metrics are difficult to construct. Historical costs for the 2022-2026 period are reflected in Section A.3. Software costs over the forecast period are expected to be higher than the historical period for the following reasons:

i. The CIS / ERP modernization concentrates a multi-year platform investment within the forecast window;

ii. Sector-wide migration from perpetual licensing to subscription-based commercial models (including the Microsoft platform) shifts more software spend into recurring capital and operating cost categories;

iii. New software is required to meet the Ontario Cyber Security Standard and to address recommendations from InnPower's independent cyber security assessments;

iv. Workforce Management / CMMS, time-to-payroll, and visitor management platforms are being implemented to replace manual or end-of-life capability; and

v. Process automation initiatives identified by the Business Process Modernization function require targeted software investment.

Accomplishments since the previous submission

Since the 2024 submission, InnPower has completed the items committed to in that filing and has delivered the following additional improvements to its software environment:

i. Completed the IT software audit referenced in the prior submission; its findings inform the prioritization and pacing of investments described in this narrative;

ii. Progressed cyber security tooling consistent with the requirements of the Ontario Cyber Security Standard, which came into force October 1, 2024;

iii. Implemented software supporting the real-time disaster recovery site established during the period (described further in IPCGP01); and

iv. Continued to sustain operations through the transition to subscription-based commercial models for core productivity software.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

This investment was scored 166.31. Within the program, priority is assigned in the following order: (i) investments required to maintain compliance with the Ontario Cyber Security Standard and other regulatory obligations; (ii) replacement of platforms supporting critical customer-facing and operational functions (CIS, ERP, Workforce Management / CMMS) that have reached end-of-support or end-of-functional-capability; (iii) sustainment of the broader software estate on its three-year refresh cadence; and (iv) discretionary process modernization and AI evaluation initiatives, which are paced according to demonstrated benefit and InnPower's capacity to absorb change.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

InnPower considered the following alternatives:

i. Do nothing: Deferring the largest platform investments was considered. This would smooth the capital profile but would extend the period during which InnPower operates aging and unsupported core platforms, increase the volume of manual workarounds and integration debt accumulating around them, and delay the efficiency, customer service, and data quality benefits that justify the investment. The compounding cost of deferral exceeds the benefit of smoothing. This option is not preferred

ii. Defer the CIS / ERP modernization to a future rate period: or CIS and workforce management/CMMS, InnPower considered following the upgrade paths proposed by incumbent vendors (e.g., ServiceLink for workforce management and mCare replacement). The ServiceLink proposal included licence, implementation, and annual fees that are material relative to InnPower's size and future investment envelope. However, given the significant current cost of the NorthStar/mCare environment and the proposed upgrade pricing within the same vendor family, InnPower determined that a broader options analysis and competitive procurement is necessary to ensure that any upgrade path is prudent and that lifecycle cost and risk are minimized. Proceeding solely with vendor-specific upgrades, without market testing, is not preferred.

iii. Carry out the proposed pacing of investments (preferred): This option allows InnPower to replace end-of-life and end-of-support platforms on a measured schedule, close cyber security gaps identified through independent assessment, sustain the broader software estate on its three-year refresh cadence, and pursue process modernization and AI evaluation in a disciplined, benefit-led manner. It incorporates competitive procurement and total-cost-of-ownership analysis for CIS, ERP, Workforce Management/CMMS, and time-to-payroll, and coordinates implementation timing so that core platforms and processes are modernized within the 2027–2031 window. This is the preferred option.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	InnPower's software portfolio is the primary lever for back-office and field productivity. Modernizing the Customer Information System, Enterprise Resource Planning, and Workforce Management / CMMS platforms removes manual workarounds that have accumulated around aging systems, reduces duplicate data entry across functions, and enables straight-through processing for core workflows such as billing, work order management, time capture, and financial approvals. Automation of finance processes (electronic approvals, mileage, expense, and timekeeping) and modernization of new-hire onboarding free staff capacity for higher-value work. The Business Process Modernization function ensures that software investment is driven by demonstrated process need rather than vendor cycles alone.
Customer Value	Customers experience InnPower primarily through the systems funded by this program: billing accuracy, customer portal self-service, Green Button data access, outage communications, and the handling of service requests all depend on the CIS and the platforms that surround it. A modern CIS, integrated with ERP and Workforce Management, supports faster service connections, more accurate bills, and richer customer-facing digital services. Security and privacy software protect the confidentiality of customer data in alignment with the Ontario Cyber Security Framework (OCSF) and the privacy principles it incorporates.
Reliability	Reliable distribution operations depend on supported, current software across both IT and OT environments. The program funds the replacement of end-of-support applications, ongoing patching and vulnerability management capability, identity and access controls aligned to a zero-trust posture, and software supporting the segregation of IT and OT networks (including SCADA isolation). Workforce Management and CMMS modernization improves the planning, dispatch, and execution of maintenance and restoration activity, which contributes directly to system reliability outcomes.
Safety	Safety outcomes are supported by accurate asset and work order information in the CMMS, controlled access to operational systems, robust visitor management at InnPower's facilities, and current software underpinning remote visibility of the distribution network. Cyber security software reduces the likelihood that a compromise of IT systems can propagate into

Primary Criteria for Evaluating Investments	Investment Alignment
	operational environments where safety consequences would be material.

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 treats its software portfolio as a strategic asset. Need for this investment arises from three principal drivers:

i. Primary driver - regulatory and lifecycle obligations: Compliance with the Ontario Cyber Security Standard is a condition of InnPower's distribution licence. Sustained software investment is required to (i) close gaps identified through independent OCSF-based cyber security assessments, (ii) maintain current security tooling across the IT estate, (iii) support the segregation of IT and OT networks, and (iv) replace software as it reaches end-of-support on InnPower's three-year refresh cycle or on the lifecycle terms set by vendors.

ii. Secondary driver - platform modernization and process efficiency: The CIS, ERP, and Workforce Management platforms have reached the practical limits of supportability and functional capability relative to current operating needs and customer expectations. InnPower's current CIS (NorthStar) is increasingly inefficient, provides limited access to usable data, and does not adequately support modern digital customer service and integration expectations. The ERP platform (Microsoft Great Plains) is approaching the end-of-support horizon announced by Microsoft for Dynamics GP, with product support ending in 2029 and security updates ending in 2031. Workforce management and maintenance capability relies in part on mCare, an unsupported product for which vendor support ended March 31, 2026, leading staff to rely on temporary workarounds such as email, text messaging, and manual interventions that are not sustainable as permanent operating practices.

    Replacing these platforms, together with time-to-payroll, visitor management, onboarding, and finance process automation, delivers measurable efficiency, accuracy, and customer service benefits. A modern ERP and integrated time-to-payroll solution form foundational infrastructure for automating financial and business processes, while modern CIS and Workforce Management/CMMS platforms provide better data for customer service, asset planning, and field operations. The Business Process Modernization function provides governance over these investments.

iii. Information used to justify the investment: InnPower maintains an inventory of software assets that records vendor, version, support status, and renewal terms. The results of the completed IT software audit referenced in the previous submission, together with the findings of independent cyber security assessments performed against the OCSF, are used to refine the prioritization and pacing of investments. InnPower also monitors guidance from the OEB, IESO, and the Canadian Centre for Cyber Security to identify emerging requirements.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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 follows industry-standard practice in managing software on a three-year lifecycle (where vendor terms permit), in aligning its cyber security program with the Ontario Cyber Security Framework (which is based on the NIST Cyber Security Framework), and in scoping CIS / ERP / Workforce Management modernization in a manner consistent with peer distributors. The Business Process Modernization and Project Manager function provides additional governance, ensuring that software investments - whether driven by lifecycle, compliance, or process improvement - are tested against efficiency and reliability outcomes before proceeding.

ii. Benefit-Cost Analysis: A benefit-cost analysis is performed for material software investments and is informed by total cost of ownership over the planned service life, expected reductions in manual effort, expected improvements in data quality and customer service metrics, and the avoided cost and risk of running unsupported software. The combination of CIS and ERP scope is being evaluated specifically against the benefit-cost of pursuing them separately.

iii. Historical Investments & Outcomes Observed: A benefit-cost analysis is performed for material software investments and is informed by total cost of ownership (TCO) over the planned service life, expected reductions in manual effort, expected improvements in data quality and customer service metrics, and the avoided cost and risk of running unsupported software. TCO includes licence fees, implementation costs, integration work, ongoing support and maintenance, upgrades, and lifecycle risk costs over the service life of each platform. For CIS and ERP, InnPower is evaluating the combination of scopes specifically against the benefit-cost of pursuing them separately, considering both implementation efficiency and lifecycle cost. For Workforce Management/CMMS, InnPower has assessed incumbent upgrade proposals (such as ServiceLink) against anticipated alternatives, recognizing that the significant costs associated with vendor-specific upgrade paths warrant competitive procurement and TCO analysis before a decision is made

Historical investments have supported uninterrupted 24/7 operations, sustained the customer portal and Green Button service, completed the IT software audit committed to in the previous submission, advanced cyber security tooling in line with the OCSF, and minimized the operational impact of cyber incidents observed across the broader sector. The proposed investments are justified on the basis that they replace end-of-life and unsupported platforms, support compliance with licence conditions, and deliver efficiency and customer-service benefits that outweigh the cost of implementation and operation.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. 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.

i. InnPower is evaluating the potential application of artificial intelligence (AI) technologies to support operational efficiency, asset management, and customer service improvements.

Areas Under Evaluation: Current areas of focus include:

- AI-assisted productivity tools for back-office functions, including document drafting, summarization, and data extraction, to reduce time spent on routine administrative activities.
- AI-supported analysis of CMMS, asset, and operational data to inform maintenance planning, identify emerging failure patterns, and improve the targeting of inspection and asset replacement activities.
- AI-assisted customer service workflows, including inquiry triage, response drafting, and self-service enhancements, to improve the speed and consistency of customer interactions.

Evaluation and Governance

- InnPower's approach to AI adoption is based on a pilot-before-scale framework. Each proposed use case is evaluated through a limited-scope pilot prior to any broader deployment decision. Proposed applications must demonstrate quantifiable benefits relative to implementation and ongoing operating costs.
- In addition, all AI use cases are reviewed for compliance with InnPower's cybersecurity and privacy obligations, including alignment with the Ontario Cyber Security Framework and applicable privacy legislation, prior to deployment.

Expected Customer Benefits:

Successful AI adoption is expected to contribute to enhanced customer service, more efficient operations, and improved asset management decision-making. Potential customer benefits include faster service, more accurate billing processes, more reliable operations, and improved targeting of maintenance and reliability investments. Over time, operational efficiencies may also contribute to cost savings that benefit customers.

InnPower intends to monitor and evaluate the outcomes of pilot activities and may report on the results of these initiatives in future filings. Where appropriate, InnPower may seek guidance through the OEB's Innovation Sandbox in advance of broader implementation.[1]

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

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., air conditioning units, windows, water heater, etc.), installation of power outlets and safety railings, and other general improvements. Without investments in these facilities, there will be a 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 2027 predominantly includes the construction of a Quonset Hut (approximately $75,000) at the operations yard to provide covered storage for aggregate materials and other equipment that cannot be exposed to weather. The additional covered storage will help preserve material quality and reduce waste and spoilage. Deferring this investment would increase the risk of material deterioration and replacement costs associated with weather-related spoilage. The remaining budget is primarily allocated towards a Building Needs Assessment (approximately $100,000), which will evaluate InnPower's current and future facility requirements to support future growth and determine whether expansions to the operations building, yard, garage, and other facilities will be required. The balance of the 2027 budget includes the replacement of an AC unit in accordance with InnPower's preventative maintenance and inspection program. InnPower plans to replace one (1) AC unit per year over the 2027–2031 period. Additionally, InnPower plans to perform a roof replacement by 2031.

2. Timing

i. Start Date: 2027

ii. In-Service Date: 2027-2031

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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	144	22	97	39	77	295	95	95	95	295
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	144	22	97	39	77	295	95	95	95	295

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Ongoing investments are made into InnPower's main operations building and yard to support 24/7 operations. Historical costs for the 2022-2026 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
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.
2023	Spend in this year was attributed to designs for customer service (CS) move, new card ID system and upgrades to yard fencing.
2024	Spend this year was due to second floor renovations to move CS, shipping container purchase for store, fence installation at the yard, HVAC unit replacement, fireproofing Ops control room, sidewalk replacement and parking lot pole repairs.
2025	Spend this year was due to building repairs, building code remediations and replacements, and fencing repairs to help with site security
2026	Spend in this year was attributed to building repairs, upgrading site security (fencing), installing an armed gate at the back, and camera replacements.

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

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

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. Deferral of these investments could also increase costs associated with material spoilage and delay assessment of InnPower's future facility requirements. These impacts could ultimately lead to the need for 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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

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 and carry out required replacements 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

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

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 benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP06 – ENGINEERING IT

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

The increasing complexity of the distribution network requires more data-driven engineering planning. Currently, Innpower is facing gaps in real-time system visibility and maintenance inefficiencies, which contribute to reliability risks.

The primary need is to build an automated and data-driven visibility and inspection system that enables more proactive maintenance and asset condition assessment, while enhancing the precision of risk identification and prioritization. These investments will support InnPower's ability to better manage vegetation risks, maintain accurate asset details and configuration information, and improve the timeliness and effectiveness of engineering analysis and operational response. This investment ensures that future capital projects support the OEB's goal of operational effectiveness.

In this DSP filling, the engineering IT program will focus on three core investments:

i. LiDAR data acquisition, where Light Detection and Ranging technology is deployed to reduce outage frequency and duration by providing detailed visibility into vegetation risks and asset conditions. LiDAR also supports early detection of issues such as conductor sag or pole lean and enables faster damage assessment and restoration planning;
ii. SurvalentONE Polaris, a utility-specific operational system tightly integrated with OMS, ADMS, SCADA, and field crews, enabling real-time outage management, switching, and restoration. The platform fully relies on the ArcGIS Utility Network as the authoritative source of network topology and asset connectivity for operational awareness and outage analysis; and
iii. Blueframe, an operational intelligence platform that provides dashboards, analytics, reporting, and workflow management by integrating data from the ArcGIS Utility Network, OMS, and CIS through APIs or feature services.

Together, these investments will improve InnPower's ability to manage vegetation risks, maintain asset and network visibility, analyze outages in real time, and support operational response. These capabilities will enhance reliability performance and enable more effective engineering planning and maintenance activities.

These investments will also support monitoring and evaluation of the system impacts associated with DER and EV penetration, enabling better coordination and response to DER/EV-driven reliability impacts.

2. Timing

i. Start Date: 2027

ii. In-Service Date: 2027-2031

iii. Key factors that may affect timing: The timing of implementation may be influenced by system integration requirements and the readiness of supporting technologies. Key factors include:

- GIS Data Migration: Innpower's underlying GIS data structure requires a major migration. While GIS readiness and integration requirements will be considered as part of implementation planning, LiDAR itself is a separate system that InnPower can benefit from. Integration with GIS will be explored concurrently to improve overall system visibility.
- Third-Party System Integration Readiness: As Blueframe and SurvalentONE Polaris continue to evolve, implementation timing may be affected by the availability and readiness of specific API integrations required between systems.

InnPower has utilized coordination with third parties (municipalities/ region/ 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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	0	0	3	57	212	642	101	101	550	250
Contributions	0	0	0	0	(115)	(321)	(50)	(50)	275	125
Capital (Net)	0	0	3	57	97	321	50	50	275	125

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Ongoing investments are being made into InnPower's Engineering IT program to support the operational effectiveness, reliability, and modernization of the distribution grid. Historical expenditures for the 2024–2026 period are provided in Section A3 of this document.

Investments in Engineering IT tools and supporting digital infrastructure began in 2024 as part of InnPower's transition toward more data-driven planning, operational visibility, and proactive asset management. These investments support enhanced system monitoring, outage response, vegetation and asset risk identification, and integration between operational platforms and GIS-based network models.

A portion of the planned expenditures for 2026–2029 is expected to be offset through NRCan funding support, helping reduce the overall cost burden while enabling continued advancement of these modernization initiatives.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

This investment priority was scored 166.3, based on its expected contribution to operational effectiveness, system reliability, and long-term grid modernization objectives, but remains a lower priority relative to other initiatives in the General Plant category. Prioritization of the selected tools was driven by specific business and operational needs, as well as the growing complexity of the distribution system and the increasing need for real-time system visibility and integrated operational intelligence.

Investments under this program are designed to fully integrate with existing operational and enterprise systems, including ArcGIS Utility Network, OMS, and CIS, through APIs and feature services. This integrated approach supports the development of a centralized, data-driven maintenance, monitoring, and asset condition assessment framework.

Collectively, these investments enhance InnPower's ability to proactively identify and prioritize risks, improve outage response and restoration planning, support DER and EV-related system monitoring, and strengthen overall system reliability and operational effectiveness.

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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

i. Do nothing: Continue relying on the current manual inspection, monitoring, and maintenance approach. This option avoids the immediate capital and implementation costs associated with the proposed investment. However, it does not address the increasing complexity of the distribution network, ongoing gaps in real-time system visibility, or growing operational needs associated with vegetation management, asset condition assessment, and outage response. Under this option, InnPower would continue to face higher risks related to asset failures, delayed identification of system issues, and limited coordination capabilities in

response to increasing DER and EV penetration. This approach was assessed as less sustainable from both a reliability and operational effectiveness perspective.

ii. Delay the investment: Delay implementation of the proposed Engineering IT investments to a later period. This option was already the case in previous COS fillings. For this round of COS, while this option may defer near-term expenditures, it would also postpone the move towards a self healing system and intelligent power restoration associated with enhanced system visibility, integrated operational intelligence, and proactive maintenance capabilities. Delaying implementation may also increase the risk of future integration challenges as operational systems and DER/EV-related impacts continue to evolve. This option was assessed as providing limited near-term value and potentially increasing long-term implementation and operational risks.

iii. Proceed with the proposed investment: Proceed with the implementation of an automated and data-driven visibility, monitoring, and inspection system. This option requires upfront investment in Engineering IT tools and system integration; however, it enables more proactive maintenance and asset condition assessment, while improving the precision of risk identification and prioritization. The proposed investments also strengthen integration between operational systems and GIS-based network models, supporting enhanced outage response, restoration planning, and operational coordination. In addition, these capabilities improve InnPower's ability to monitor and respond to system impacts associated with DER and EV adoption. This option was assessed as the preferred alternative as it best aligns with the OEB's objectives related to operational effectiveness, reliability, and grid modernization.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 2: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By utilizing LiDAR and Blueframe, InnPower is advancing toward a more automated and data-driven operational model, reducing reliance on manual inspection and assessment processes. These tools improve the efficiency of vegetation management, asset condition monitoring, damage assessment, and restoration planning, while enabling faster access to system-wide operational intelligence. Integration between Blueframe, ArcGIS Utility Network, OMS, and CIS also supports streamlined workflows, improved data accessibility, and more coordinated operational decision-making.
Customer Value	Accurate system visibility and network modeling through SurvalentONE Polaris support more informed operational and capital planning decisions, helping ensure that system upgrades and maintenance activities are appropriately prioritized and right-sized. This reduces the likelihood of both over-investment and under-investment in infrastructure, ultimately supporting cost-effective service delivery and ensuring customers pay only for investments that are demonstrated to be necessary for reliability and operational performance.
Reliability	The proposed investments significantly enhance InnPower's ability to proactively identify, assess, and respond to reliability risks across the distribution system. The high-resolution and three-dimensional precision of LiDAR technology enables earlier detection of vegetation encroachments, conductor sag, pole lean, and other asset-related risks, particularly during or following extreme weather events. These capabilities support reductions in outage frequency and duration by enabling proactive maintenance and faster restoration planning. Blueframe improves operational visibility, analytics, and decision-making speed, enabling quicker identification of system issues and more coordinated response actions. SurvalentONE Polaris further enhances reliability through integration with OMS, ADMS, SCADA, and GIS systems, enabling faster fault location, optimized switching operations, and improved field crew coordination. Collectively, these investments contribute to improvements in reliability performance metrics such as SAIDI and SAIFI.
Safety	LiDAR supports a transition from manual and reactive inspection practices toward a safer and more proactive data-driven approach. Remote identification of vegetation encroachments, asset deterioration, and structural risks reduces the need for frequent field-based inspections in potentially hazardous environments. Enhanced operational visibility and integrated system awareness also improve situational awareness for field crews and system operators during outage response and restoration activities, contributing to improved worker and 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.

The proposed Engineering IT investments are intended to support InnPower's transition toward a more integrated, data-driven, and operationally responsive distribution system. As the distribution network becomes increasingly complex, there is a growing need for enhanced system visibility, proactive asset management, and coordinated operational intelligence to support reliability and operational effectiveness.

i. Main Driver: The primary need for this suite of tools is to build an automated and data-driven visibility, monitoring, and inspection system that enables more proactive maintenance and asset condition assessment, while enhancing the precision of risk identification and prioritization. LiDAR technology helps InnPower reduce outage frequency and duration by providing detailed visibility into vegetation risks and asset conditions. The technology also supports early identification of issues such as conductor sag, pole lean, and vegetation encroachments, enabling more proactive maintenance planning and faster restoration response. Blueframe is an operational intelligence platform that provides dashboards, analytics, reporting, and workflow management by integrating data from the ArcGIS Utility Network, OMS, and CIS through APIs or feature services. This integration improves operational visibility, data accessibility, and coordination across systems and operational teams. SurvalentONE Polaris is a utility-specific operational platform tightly integrated with OMS, ADMS, SCADA, and field crews, enabling real-time outage management, switching, and restoration activities. The platform relies on GIS-based network topology and connectivity data to support enhanced operational awareness and decision-making.

ii. Secondary Drivers: A secondary driver for these investments is the increasing need to monitor, coordinate, and respond to system impacts associated with growing EV adoption and DER penetration. Enhanced operational visibility, integrated system intelligence, and improved analytics capabilities will better position InnPower to assess and respond to evolving load patterns, localized system constraints, and reliability impacts associated with electrification trends.

iii. Information Used to Justify the Investment: The investment was justified based on operational and reliability needs identified through existing limitations in manual inspection and maintenance practices, increasing requirements for real-time system visibility, and the growing complexity of distribution system operations. Consideration was also given to the need for improved outage response and restoration capabilities, enhanced asset condition monitoring, integration between operational systems and GIS-based network models, and the anticipated impacts of DER and EV growth on system planning and reliability.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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: The proposed investments align with industry-wide utility modernization practices focused on improving operational visibility, outage response, asset condition monitoring, and data-driven maintenance planning. Distribution utilities are increasingly adopting technologies such as LiDAR, integrated OMS/ADMS/SCADA platforms, GIS-based network models, and operational intelligence platforms to support grid modernization and improve reliability performance. The use of LiDAR technology for vegetation management, asset condition assessment, and damage inspection is an established utility practice that supports proactive maintenance and reduced outage risks. Similarly, integrated operational platforms such as SurvalentONE Polaris and operational intelligence tools such as Blueframe are commonly used across utilities to enhance outage management, switching coordination, analytics, reporting, and system-wide operational awareness. Integration with ArcGIS Utility Network also reflects current industry practices for maintaining an authoritative network model to support operational and planning functions.

ii. Benefit-Cost Analysis: The proposed investments were assessed against alternatives including maintaining existing manual inspection and monitoring processes or delaying implementation. While the "do nothing" alternative avoids near-term capital expenditures, it does not address increasing operational complexity, limitations in real-time system visibility, or growing reliability risks associated with vegetation management, asset condition deterioration, and DER/EV penetration. Delaying the investments would similarly postpone operational and reliability benefits while potentially increasing future integration and implementation risks.

Proceeding with the proposed investments provides long-term operational and customer benefits through improved reliability, faster outage response and restoration, more proactive maintenance practices, and enhanced precision in risk identification and prioritization. The investments also support more informed and right-sized capital planning decisions, reducing the likelihood of inefficient infrastructure investments over time. In addition, integration between operational systems and GIS-based network models improves data accessibility, workflow coordination, and operational decision-making across the organization.

iii. Historical Investments & Outcomes Observed: InnPower has been making ongoing investments in Engineering IT tools and supporting digital

infrastructure since 2024 to improve operational effectiveness and support modernization initiatives. Historical expenditures for the 2022−2026 period are reflected in Section A3 of this document.

Initial investments in integrated operational and GIS-based systems have supported improved system visibility, enhanced data integration, and more efficient operational workflows. These investments have also established the foundational infrastructure required to support future enhancements related to outage management, proactive maintenance, and DER/EV monitoring capabilities. A portion of the planned expenditures for 2026−2029 is also expected to be offset through NRCan funding support.

iv. Substantially Exceeding Materiality Threshold: The proposed Engineering IT investments support strategic grid modernization initiatives related to operational systems, GIS integration, analytics platforms, and data-driven inspection technologies. These investments are expected to provide long-term customer and operational benefits through improved reliability, enhanced operational coordination, proactive maintenance planning, and reduced outage risks.

The expenditures were evaluated based on operational needs, alternatives considered, integration requirements, customer value, and long-term reliability impacts, while aligning with the OEB's objectives related to operational effectiveness and prudent asset management.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP07 – MEASURING & TESTING 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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

To maintain a safe and reliable system, Innpower must move away from a reactive maintenance strategy. The current inventory of testing equipment is approaching the end of its useful life or lacks the sensitivity required to detect early-stage insulation breakdowns.

Without modern diagnostic tools, Innpower risks delayed identification of anomalies in connections, conductors, and deteriorating assets across its Distribution Stations, which, if not detected and addressed appropriately, could potentially lead to equipment burnouts, switchgear failures, and cascading outages.

The scope of this program involves the procurement and lifecycle replacement of specialized field diagnostic hardware, particularly Infrared (IR) Thermography and Insulation Resistance Testing (Megger) equipment. High-resolution IR cameras will be acquired to support annual inspections of 10 Distribution Stations, while modern Megger units will be deployed to verify the integrity of cables, transformers, and switchgear during scheduled maintenance activities. The program also includes fixed thermal and security cameras at Distribution Stations to support ongoing monitoring and improve visibility of station conditions.

The test-year investment has been reviewed and adjusted to align with forecast requirements, including a reduction of the planned spending while maintaining the intended benefits of improved asset monitoring and proactive maintenance capabilities.

2. Timing

i. Start Date: 2027

ii. In-Service Date: 2027-2031

iii. Key factors that may affect timing:

- Asset condition-driven acceleration: If a mid-period Asset Condition Assessment (ACA) identifies faster-than-anticipated degradation in a specific transformer class or other critical asset groups, Innpower may accelerate the procurement of high-sensitivity diagnostic equipment to enhance condition monitoring capabilities and support earlier intervention activities.
- Vendor and equipment lifecycle risk: Unexpected manufacturer End-of-Life (EOL) announcements, including discontinued support, limited spare part

availability, or technology obsolescence, could require earlier replacement of existing diagnostic tools such as Megger units and IR cameras.

- Regulatory and standards changes: Changes to regulatory requirements, mandatory inspection cycles, or industry testing standards may alter the proposed implementation timeline and require earlier deployment of upgraded diagnostic equipment.

3. Historical and Future Capital Expenditures

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	0	0	8	0	208	190	246	246	320	320
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	8	0	208	190	246	246	320	320

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Ongoing investments in Innpower's Measuring and Testing equipment are being undertaken to support operational effectiveness, strengthen asset condition monitoring capabilities, and maintain the reliability and safety of the distribution system. Historical expenditures for the 2024–2026 period are provided in Section A3 of this document.

Targeted investments in Measuring and Testing equipment commenced in 2024 to enhance Innpower's ability to proactively identify emerging asset issues and support informed maintenance decisions. These investments include metering equipment, Infrared (IR) Cameras used for inspection activities across 10 Distribution Stations, and Megger equipment for insulation resistance testing of critical assets. The proposed investments build upon this historical approach and represent a continuation of Innpower's strategy to improve diagnostic capabilities and reduce the risk of equipment failures and unplanned outages.

Table 2: Historical Testing Equipment Procured

Year	Description of Testing Equipment Procured
2024	Portable Thermal Camera (FLIR E96 WITH DFOV 24 AND 14 DEG)
2026	Fix Security and Thermal Camera in progress

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

This investment priority was scored 166.3, based on its expected contribution to operational effectiveness, enhancement of asset condition monitoring capabilities, and support for the reliability and safety of the distribution system. This investment program is considered low priority relative to other initiatives within the General Plant category. The prioritization of the selected tools is driven by Innpower's transition toward a more objective, data-driven asset condition management approach that enables improved visibility into asset health and risk exposure.

Collectively, these investments enhance Innpower's ability to proactively identify, assess, and prioritize emerging risks, while enabling more targeted and effective corrective actions during planned maintenance activities. By improving the early detection of asset deterioration and potential failures, these tools support the extension of asset life, reduce the likelihood of unplanned outages, and contribute to a more efficient and predictable capital expenditure profile over 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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

i. Do nothing: Under the do-nothing alternative, Innpower would continue relying on aging diagnostic equipment with limited sensitivity and functionality. This approach increases the risk of delayed identification of anomalies in connections, conductors, and deteriorating assets across Distribution Stations. Failure to detect and address these issues in a timely manner could lead to equipment burnouts, switchgear failures, reduced asset reliability, and, in severe cases, broader system impacts such as cascading outages. In addition, this option would limit Innpower's ability to transition toward a proactive, data-driven asset management approach and may result in increased corrective maintenance and higher long-term costs.

ii. Proceed with Proposed Investment: Proceeding with the proposed investment strengthens Innpower's diagnostic and condition-monitoring capabilities by providing modern, high-sensitivity testing equipment. This option supports earlier

detection of emerging asset issues, enables more effective prioritization of maintenance activities, and reduces the likelihood of unexpected failures and service interruptions. It also aligns with Innpower's objective of transitioning toward an objective, data-driven asset condition management framework while supporting improved reliability, operational effectiveness, and long-term asset life extension.

iii. Utilize Third-Party Contractors: Under this option, Innpower would outsource diagnostic testing and inspection activities to external contractors rather than develop internal capabilities. While this approach could reduce near-term capital expenditures, recurring contractor costs across multiple stations and inspection cycles would likely exceed the cost of equipment ownership over a relatively short payback period. Furthermore, reliance on external resources may reduce scheduling flexibility, increase response times for urgent inspections, and limit the development of internal expertise and operational knowledge. Building in-house capability provides greater responsiveness and long-term value for ratepayers while supporting ongoing asset management needs.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 3: Investment Evaluation – Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	IR cameras enable live-line inspections without requiring equipment outages or service interruptions, improving the productivity and effectiveness of maintenance activities. This capability reduces operational constraints, enhances inspection efficiency, and allows maintenance crews to assess a larger number of assets within available work windows.
Customer Value	Enhanced diagnostic capabilities support early identification of deteriorating assets before failures occur. For example, identifying a failing transformer through Megger testing can avoid costly emergency repairs, environmental cleanup activities, and unplanned service restoration efforts. By reducing reactive maintenance requirements and minimizing high-cost failure events, these investments help lower the long-term cost of service and provide greater value to customers.
Reliability	Regular condition assessments through IR thermography provide early indication of abnormal operating conditions, deteriorating connections, and equipment fatigue. Early detection allows for planned corrective action before issues escalate into failures, reducing the risk of station outages and minimizing potential service interruptions that could affect large groups of customers.
Safety	These diagnostic tools play a critical role in supporting worker and system safety. IR cameras enable technicians to perform inspections from a safe distance while equipment remains energized, reducing exposure to high-voltage hazards. Similarly, Megger testing verifies insulation integrity and helps ensure that equipment is safe for maintenance personnel to handle and operate, reducing risks associated with equipment failure or unsafe working conditions.

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: The primary driver for this investment is the need to improve Innpower's ability to monitor, assess, and manage the condition of critical distribution assets through modern diagnostic technologies. Existing testing equipment is approaching the end of its useful life and, in some cases, lacks the sensitivity required to identify early-stage deterioration and insulation breakdowns. As Innpower continues to transition toward a more proactive and data-driven asset management framework, enhanced diagnostic tools are required to provide greater visibility into asset health, support informed maintenance decisions, and reduce the risk of unplanned equipment failures and service disruptions.

ii. Secondary Drivers: In addition to improving asset condition visibility, this investment supports several secondary objectives related to reliability, operational effectiveness, safety, and long-term cost optimization. Advanced diagnostic tools improve the ability to identify deteriorating assets and abnormal operating conditions before failures occur, allowing maintenance activities to be planned more effectively and reducing reliance on reactive interventions.

iii. Information Used to Justify the Investment: The proposed investment has been justified through a combination of asset condition considerations, operational requirements, historical investment patterns, and expected business outcomes. Key inputs include the current condition and limitations of existing measuring and testing equipment, annual inspection requirements for Distribution Stations, historical expenditures and investment trends, and findings from asset condition assessments identifying degradation risks within critical assets.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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: Utilities increasingly rely on diagnostic technologies such as Infrared (IR) thermography and insulation resistance testing to support condition-based maintenance programs and proactively identify deteriorating assets before failures occur. The use of these tools reflects a broader industry shift away from reactive maintenance approaches toward data-driven asset management practices.

ii. Benefit-Cost Analysis: The proposed investment is expected to generate benefits that extend beyond the initial capital expenditure through improved operational efficiency, reduced risk exposure, and lower long-term maintenance costs. By reducing the likelihood of equipment failures, service interruptions, and reactive repairs, the investment supports lower lifecycle costs while also improving system reliability and safety outcomes. Furthermore, in-house ownership of the equipment avoids recurring contractor costs and provides operational flexibility that delivers long-term value for ratepayers.

iii. Historical Investments & Outcomes Observed: Previous investments initiated in 2024 included metering equipment, IR cameras, and Megger equipment to support asset inspection and condition assessment activities. These investments enhanced Innpower's ability to proactively identify asset issues and support more informed maintenance decisions. The proposed investment builds on this established approach and represents a continuation of efforts to strengthen diagnostic capabilities and support long-term asset management objectives.

iv. Substantially Exceeding Materiality Threshold: The proposed investment does not represent a standalone transformational project such as a major enterprise system implementation or large-scale infrastructure expansion; rather, it reflects targeted investments in specialized diagnostic tools that support broader asset management objectives.

4. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

IPCGP12 – FLEET

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, volume of work expected to be completed, 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 benefit-cost analysis results of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

InnPower currently controls and manages 29 fleet vehicles, comprised of SUVs work 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.

Table 1: InnPower Fleet List (as of May 15, 2026)

Year	Vehicle Type	Vehicle Number	Ownership
1998	Trailer (Tensioner)	V407	Own
1998	Trailer (Puller)	V408	Own
2007	Heavy Truck (Single Bucket Truck)	V307	Own
2010	Trailer	V401	Own
2010	Trailer	V404	Own
2010	Heavy Truck (Single Bucket Truck)	V302	Own
2010	Trailer	V402	Own
2011	Heavy Truck (Radial Boom Derrick)	V201	Own
2014	SUV	V99	Own
2014	SUV	V97	Own
2014	SUV	V98	Own
2015	Trailer	V405	Own
2017	Heavy Truck (Single Bucket Truck)	V304 20	Own
2018	SUV	V082 19	Own
2018	SUV	V081 19	Own
2018	SUV	V102 19	Own
2018	Heavy Truck (Double Bucket Truck)	V303	Own
2020	SUV	V106	Own
2021	Heavy Truck	V104	Own
2021	Heavy Truck (Radial Boom Derrick)	V202	Own
2022	Heavy Truck	V103	Own
2023	SUV	V105	Own
2023	Heavy Truck (Single Bucket Truck)	V305	Own
2023	SUV	V85	Own
2023	SUV	V86	Own
2023	SUV	V87	Own

Year	Vehicle Type	Vehicle Number	Ownership
2023	Trailer	V406	Own
2024	Heavy Truck (Single Bucket Truck)	V306	Own
2025	Trailer	V403	Own

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 forecast program budget will comprise a mix of end-of-life fleet replacements, bucket truck purchases, and additions based on staff growth to accommodate InnPower's growing customer base. The planned budget over the 2027 – 2031 period varies year to year based on specific needs identified. The higher forecast spending in 2027 reflects the procurement timing associated with large fleet vehicles. Larger fleet assets, such as bucket trucks, have an estimated three-year lead time from order placement to delivery. As a result, costs are incurred over the period required for vehicle construction rather than being evenly distributed across the full 2027–2031 forecast period. This results in higher expenditures in years where long-lead fleet purchases are initiated.

InnPower plans to purchase one (1) new bucket truck in 2027 and replace two (2) existing bucket trucks in 2030 and 2031. The 2027 bucket truck purchase includes a 90-foot double bucket truck (approximately $850,000) with a three-year lead time. This vehicle is required to accommodate taller poles associated with system expansion and storm hardening initiatives. The 2030 replacement includes a 90-foot double bucket truck replacement for vehicle V303 (approximately $850,000), and the 2031 replacement includes a 65-foot single bucket truck replacement for vehicle V304 (approximately $650,000). These replacements are required due to end-of-life considerations and to support operational requirements associated with taller poles resulting from expansion and storm hardening initiatives.

In addition to the bucket truck program, InnPower will add two (2) new F150 supervisor vehicles over the forecast period, with one (1) in 2027 and one (1) in 2029, to support staffing growth. The 2027 F150 addition includes a new shared supervisor vehicle to support staffing levels, while the 2029 F150 addition includes a new supervisor vehicle to accommodate additional staffing requirements. InnPower will also replace two (2) F250 vehicles, with one (1) replacement in 2028 and one (1) replacement in 2029 due to end-of-asset-lifecycle considerations. Additional fleet purchases over the forecast period include a loader in 2027 to support asset movement, screening and sand activities for backfilling, reduce reliance on rental equipment for work activities, and support general facility cleanliness and maintenance. InnPower also plans to replace the 2011 radial boom derrick (RBD) truck and a stringing machine in 2028 due to end-of-asset-lifecycle considerations. These additional vehicle purchases are intended to support operations associated with new employees as InnPower staffs up to meet future needs.

2. Timing

i. Start Date: January 2027

ii. In-Service Date: 2027-2031

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 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)					Future Costs ($ '000)				
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital (Gross)	46	681	432	82	500	845	1,920	475	550	1,065
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	46	681	432	82	500	845	1,920	475	550	1,065

The overall program costs detailed above are inclusive of inflation, material/labour charges, project management, and contingencies.

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical costs for the 2022-2025 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:

- 2022: No new vehicles were purchased; regular maintenance was performed.
- 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.

- 2024: InnPower finalized the purchase of the new bucket truck to replace the existing single bucket truck V302.
- 2025: No new vehicles were purchased; continued preventative maintenance increased due to the cost of ageing fleet
- 2026: This cost is driven by the purchase of a used bucket truck and the replacement of vehicles at the end of their life for the following vehicles: V97 and V99.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

This is a medium-to-high-priority investment that was scored 405.4. 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

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

With every vehicle replacement, department needs are reviewed to determine the best option. InnPower considered the following alternatives:

i. Do nothing: This option is not viable as doing nothing (i.e., retaining vehicles at the end of their lifetime) will result in an increase in regular maintenance and repair costs and will not address the mileage accumulated on the 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. Leasing vehicles: InnPower considered whether a leasing model would be possible, however leased specialized vehicles, such as bucket trucks, are not reliably available due to supply chain issues. As a result, this option was discarded.

iii. Like-for-like replacement of vehicles: Under this option, InnPower will undertake like-for-like replacement of vehicles in line with the fleet replacement considerations outlined in the Fleet Management Policy (Appendix A6). By utilizing

this approach, InnPower will ensure that it will have safe and reliable vehicles required to support system maintenance and capital investment activities.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

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 the OEB's Filing Requirements for Electricity Transmission Applications (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. The OEB will also consider whether the project/program supports economic growth in accordance with the policies of the government of Ontario.

Table 3: 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. An 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 vehicles 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 vehicles 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.

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 (Appendix A6) which outlines the roles, responsibilities, and suggested criteria and scoring guideline for the replacement of vehicles.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or benefit-cost 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. Benefit-Cost 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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies.*

This is not applicable.

APPENDIX – A1

2022 BARRIE-INNISFIL INTEGRATED REGIONAL RESOURCE PLAN

Integrated Regional Resource Plan

Barrie/Innisfil
May 2022

ieso
Connecting Today.
Powering Tomorrow.

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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

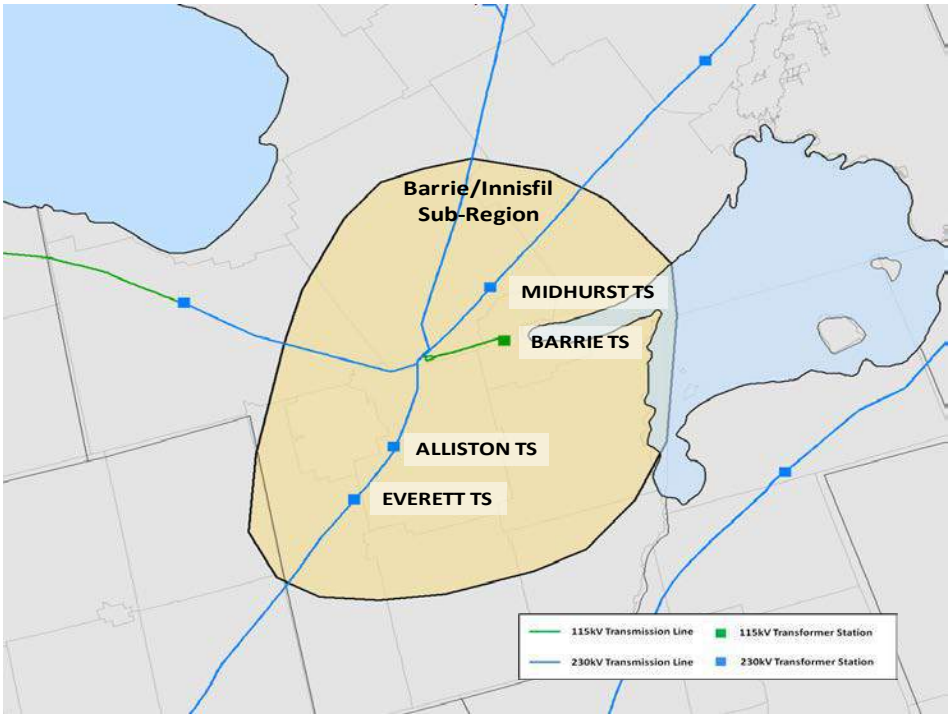
The Technical Working Group assessed the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions 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

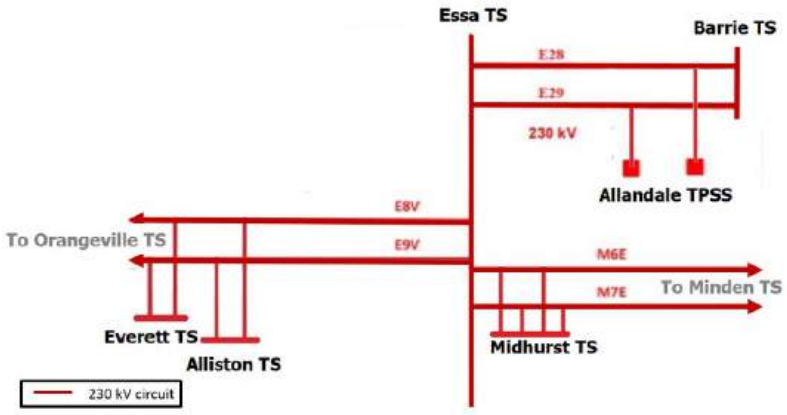
This IRRP develops and recommends options to meet the electricity needs of the Barrie/Innisfil sub-region. The plan was prepared by the IESO on behalf of the Technical Working Group. The plan includes consideration of forecast electricity demand growth, CDM, DG, transmission and distribution system capability, 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

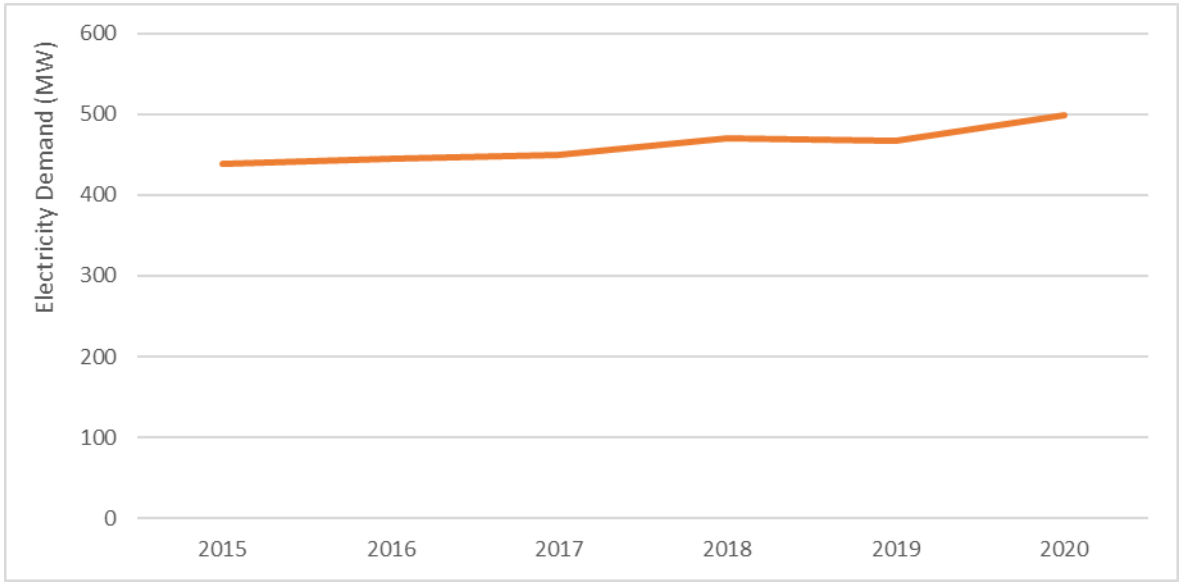
Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the Barrie/Innisfil sub-region. It highlights the assumptions made for peak demand forecasts 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.

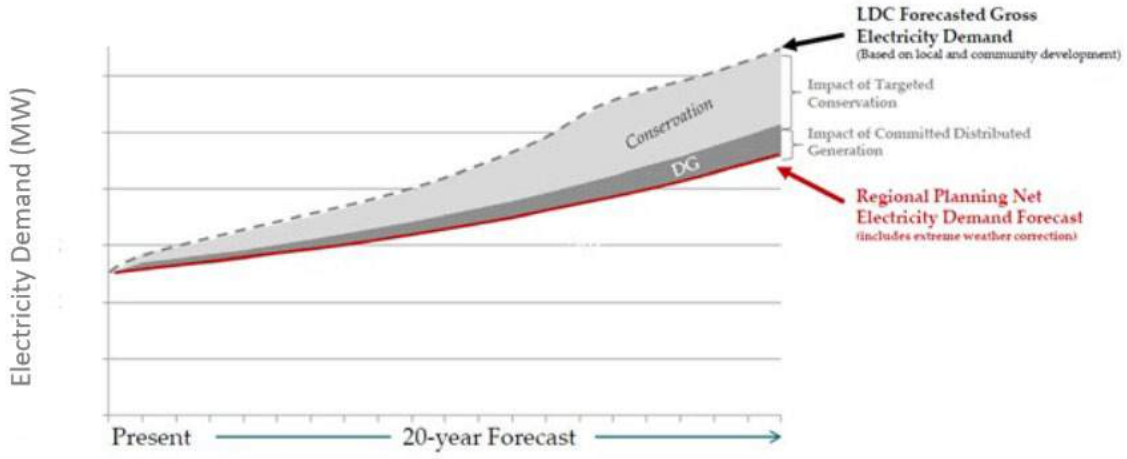
Figure 3 | Historical Summer Peak Demand – Barrie / Innisfil Sub-region



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



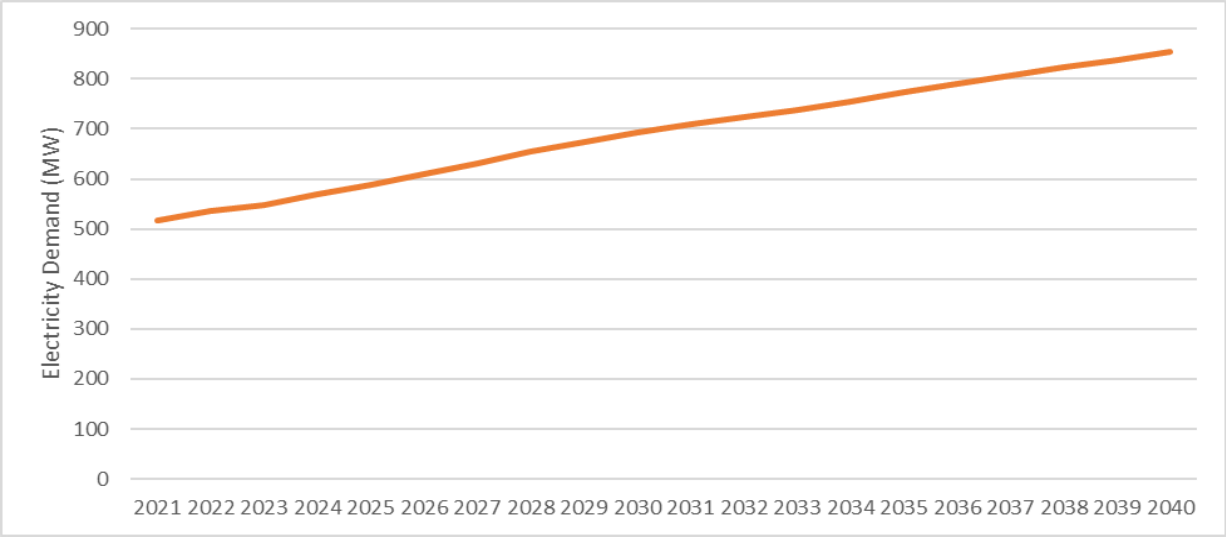
5.3 Gross LDC Forecast

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

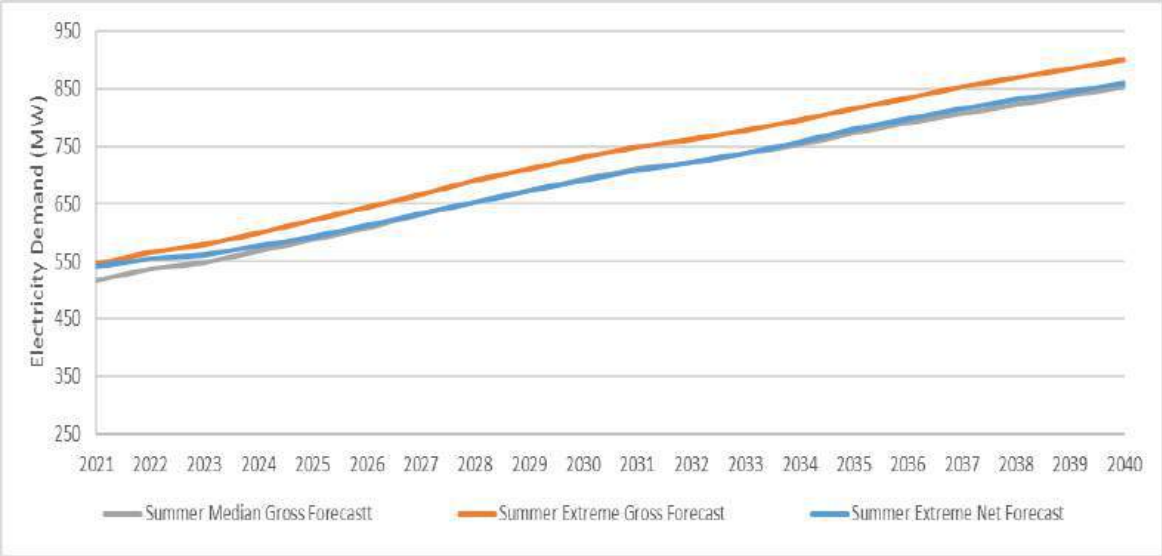
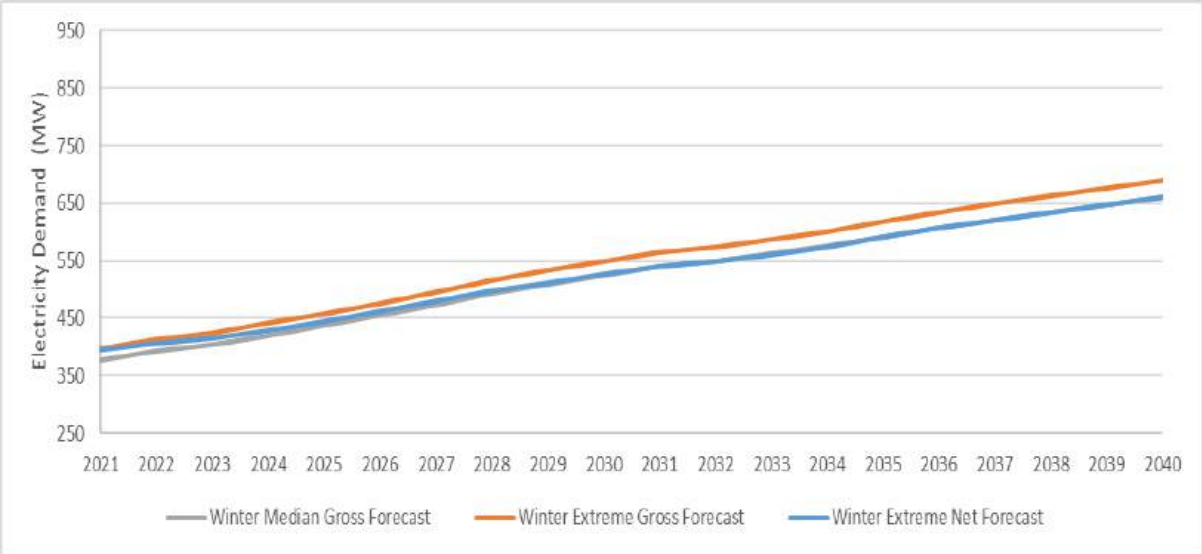


Figure 7 | Winter Net Extreme Weather Demand Forecast



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

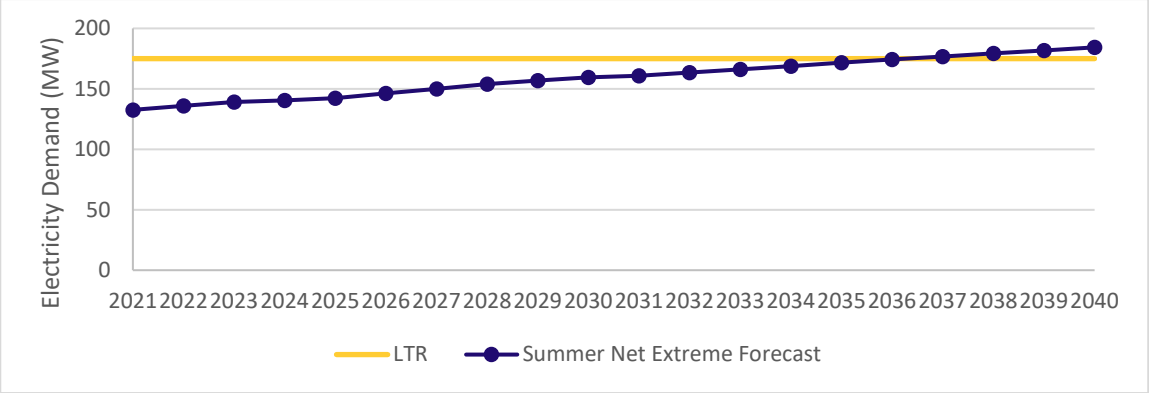
Table 4 and Figure 9 to Figure 12 below show transformer capacity limitations for the Barrie/Innisfil sub-region. In the near/mid-term, there are capacity limitations at Barrie TS and Everett TS. There is also a supply capacity constraint at the 44 kV feeder level for Barrie TS starting in 2025 at the 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

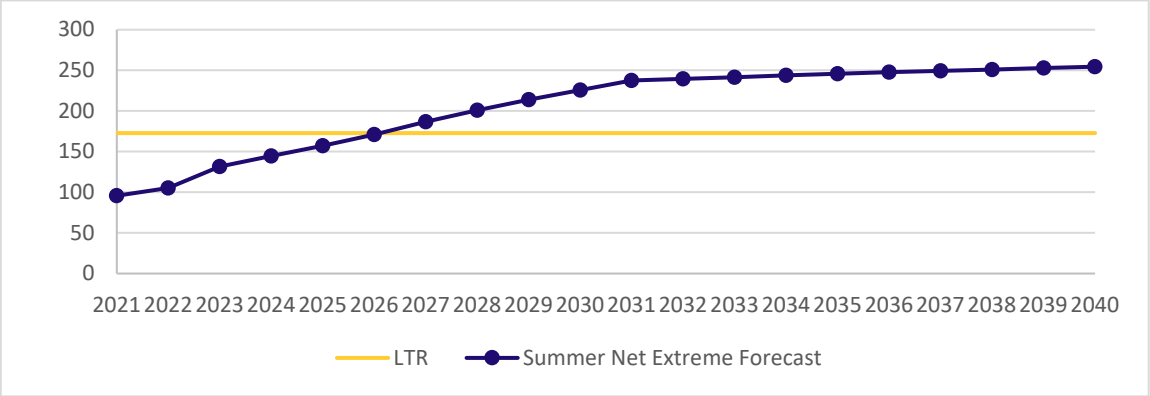


Figure 11 | Everett TS Capacity Need

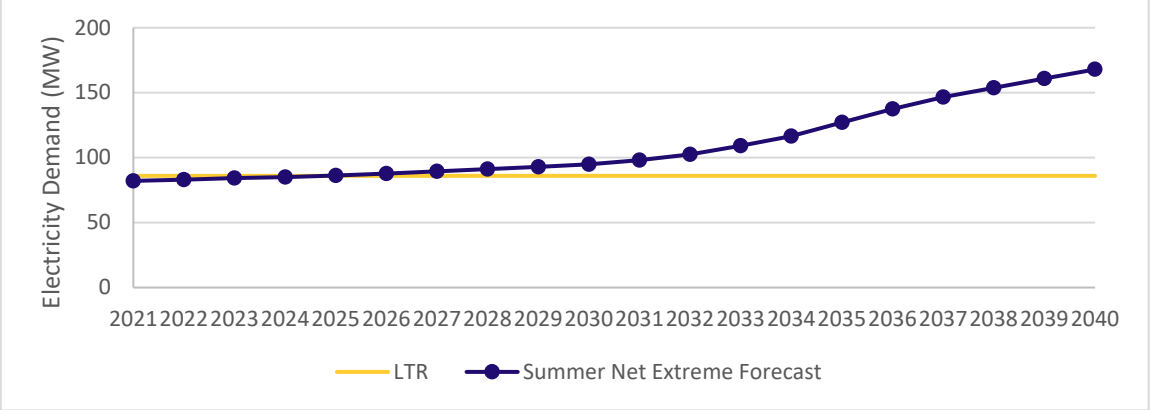
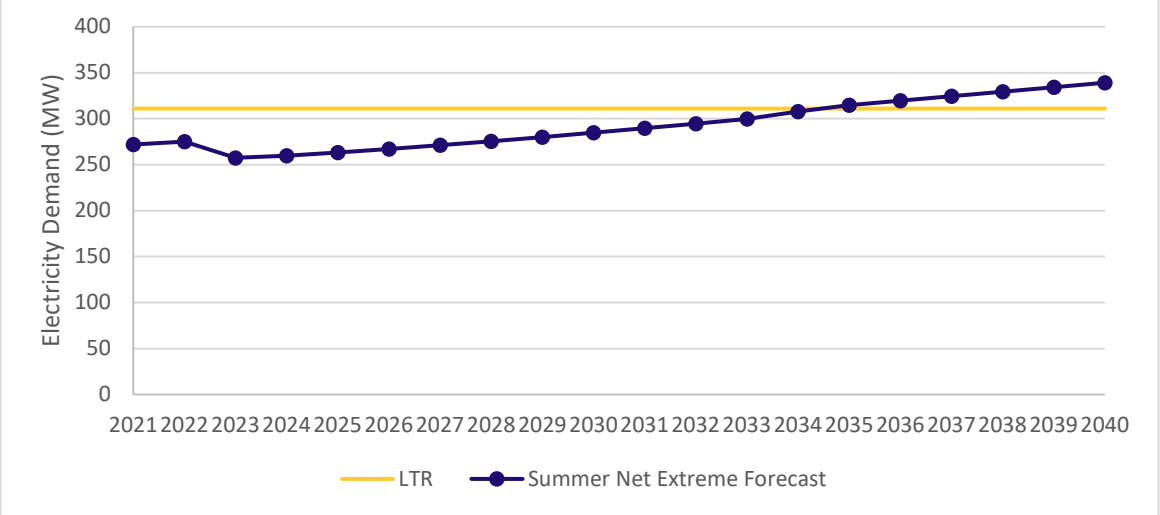


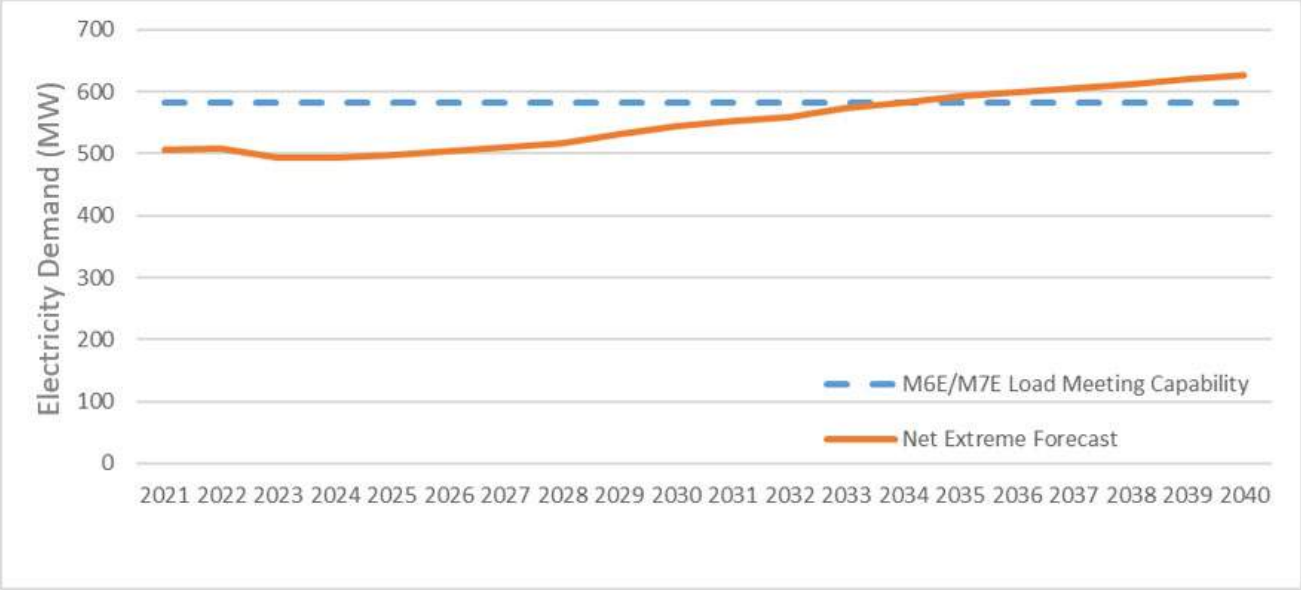
Figure 12 | Midhurst TS Capacity Need



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.

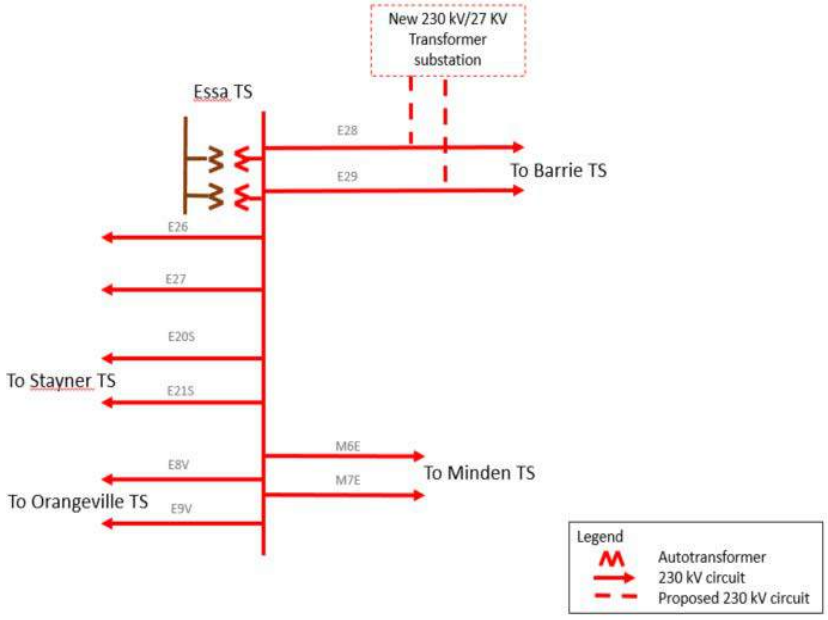
A variety of wires options are considered to address the increased demand growth served by Barrie TS and the supply capacity constraint at the 44 kV feeder level. These wires options are formulated from the detailed options analysis conducted after the Needs Assessment between the transmitter and the 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

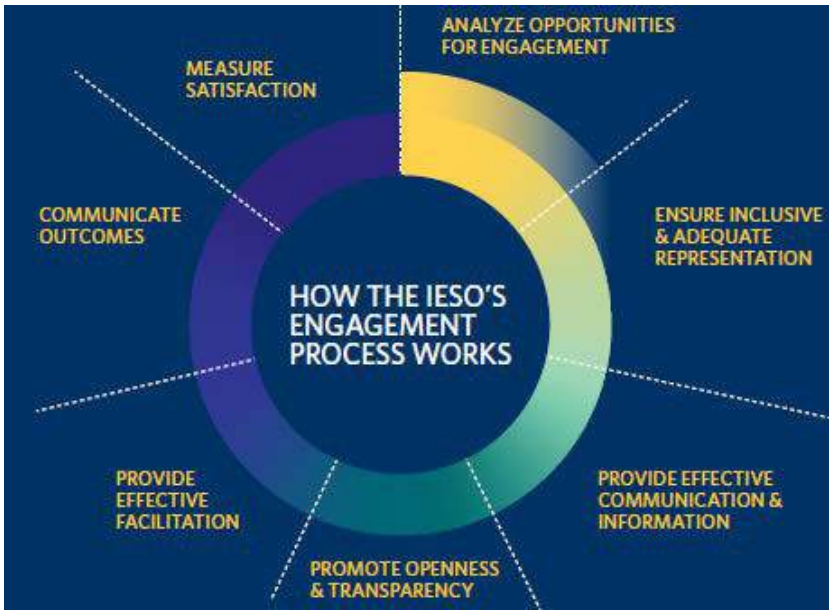
8. Engagement and Consultation

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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APPENDIX – A2

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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Alectra Utilities Corporation (Alectra)
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.

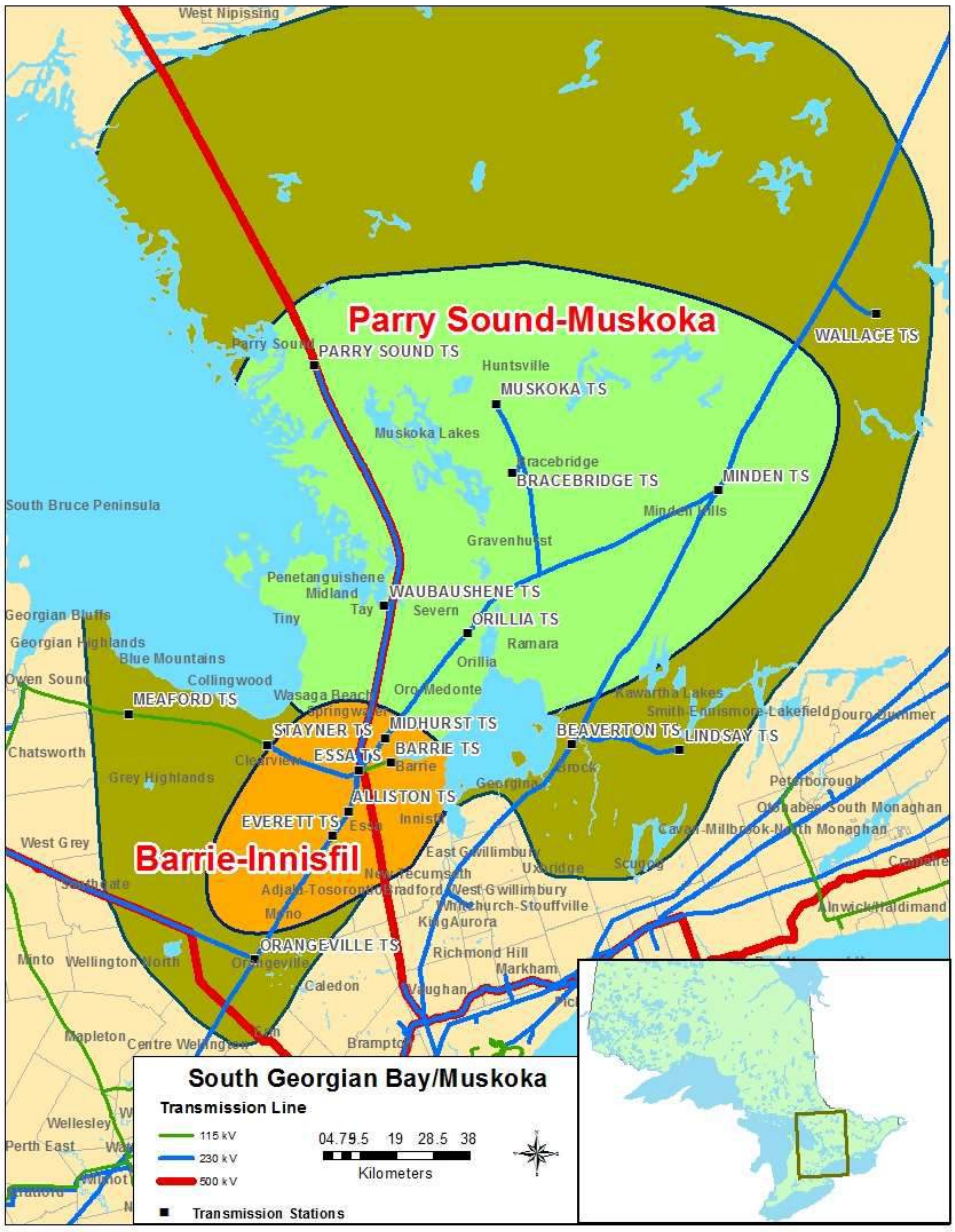


Figure 1-1 South Georgian Bay-Muskoka Region Map

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.

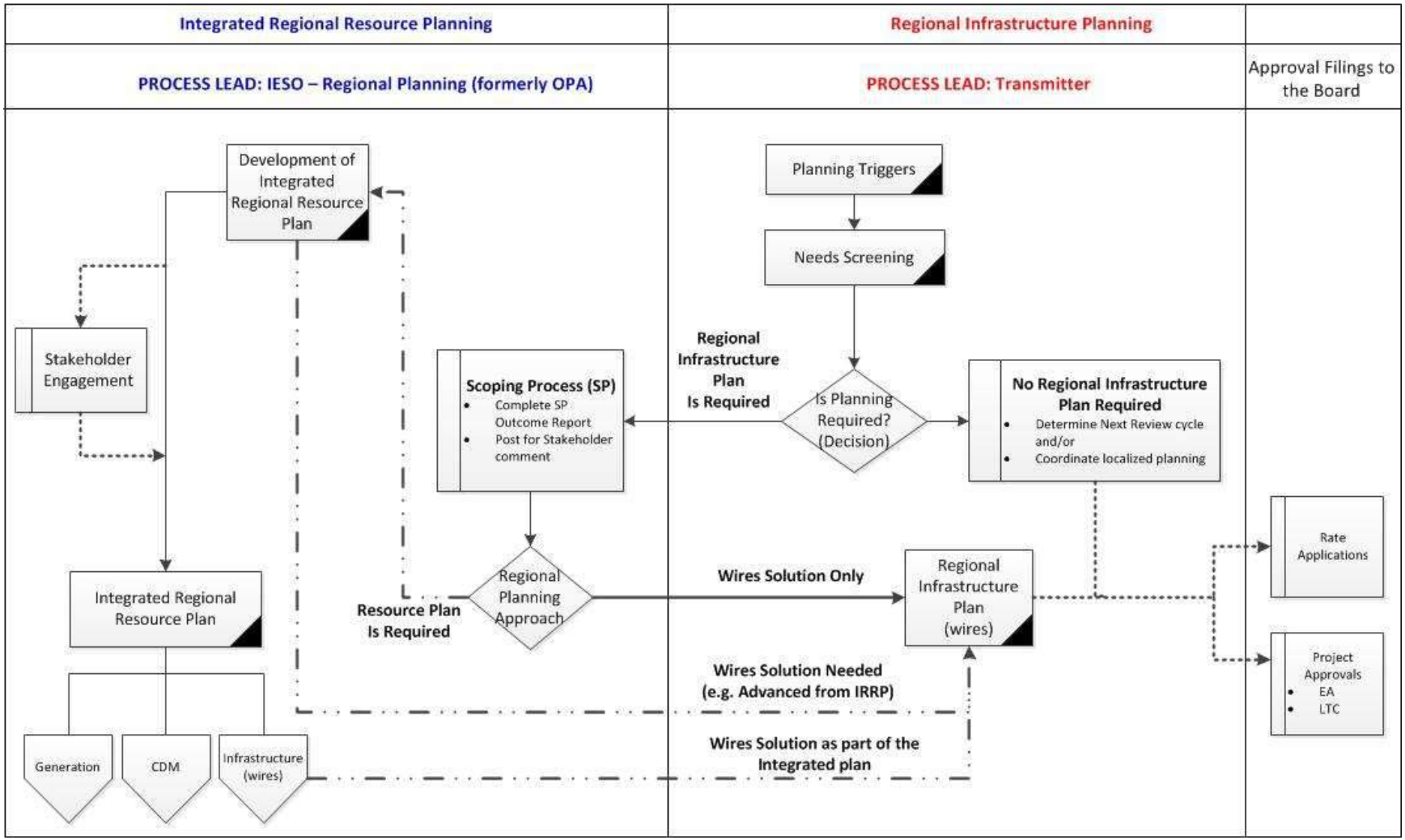


Figure 2-1 Regional Planning Process Flowchart

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.

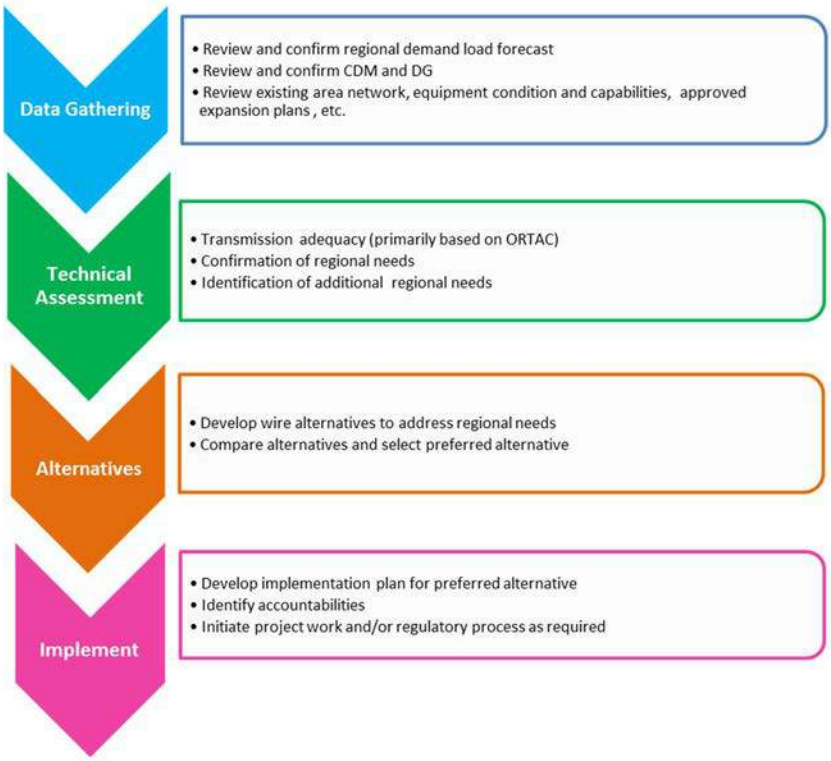


Figure 2-2 RIP Methodology

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 D4M 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.

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.

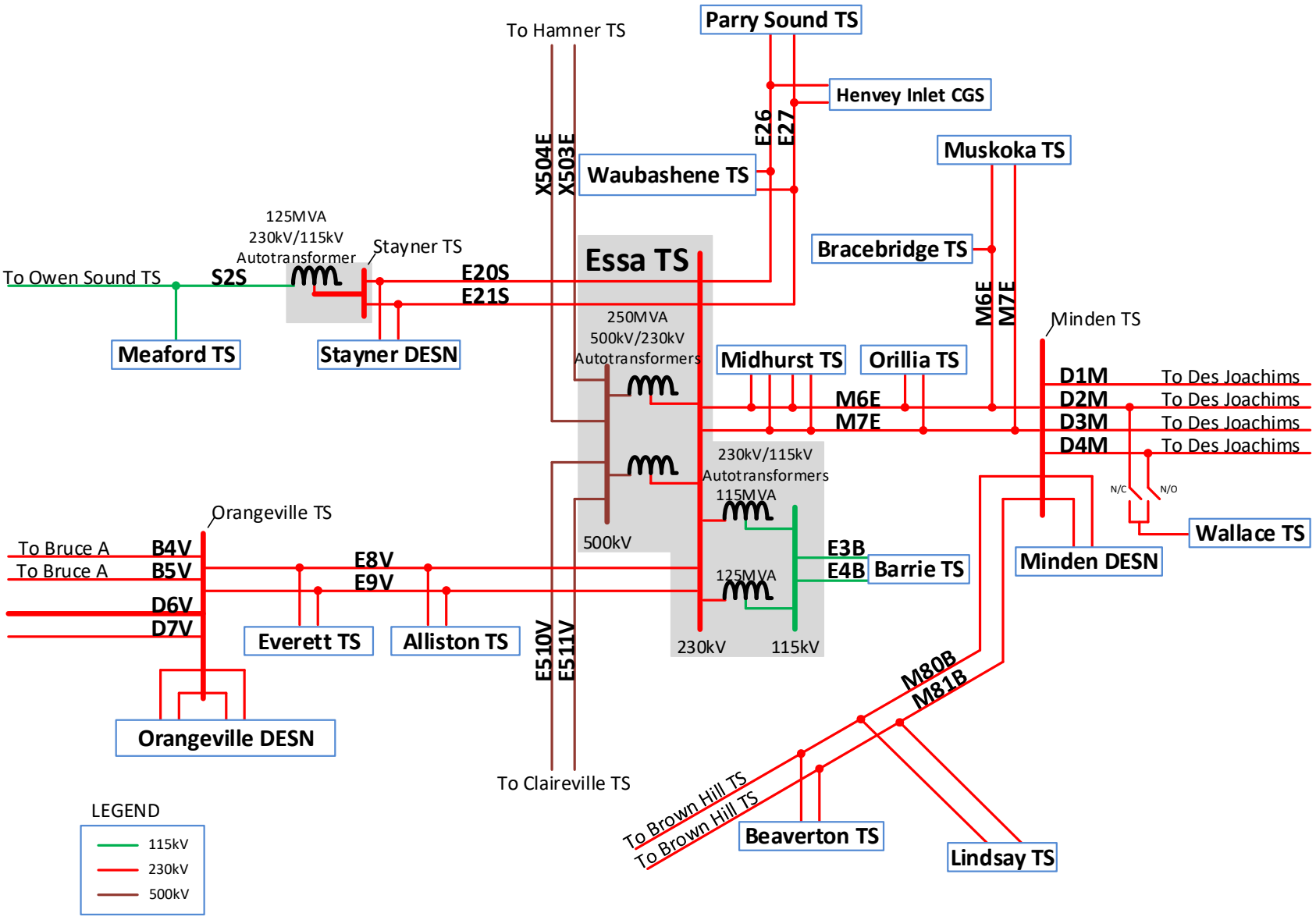
There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

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.

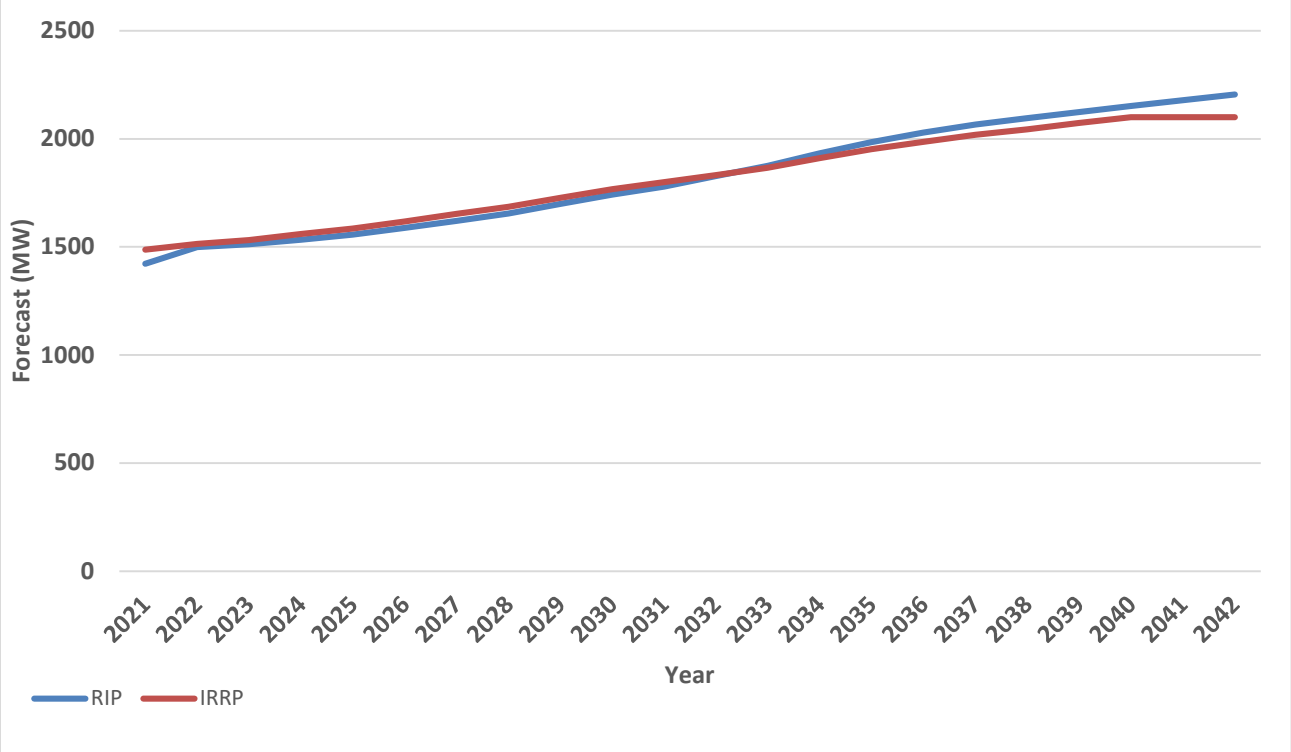


Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast

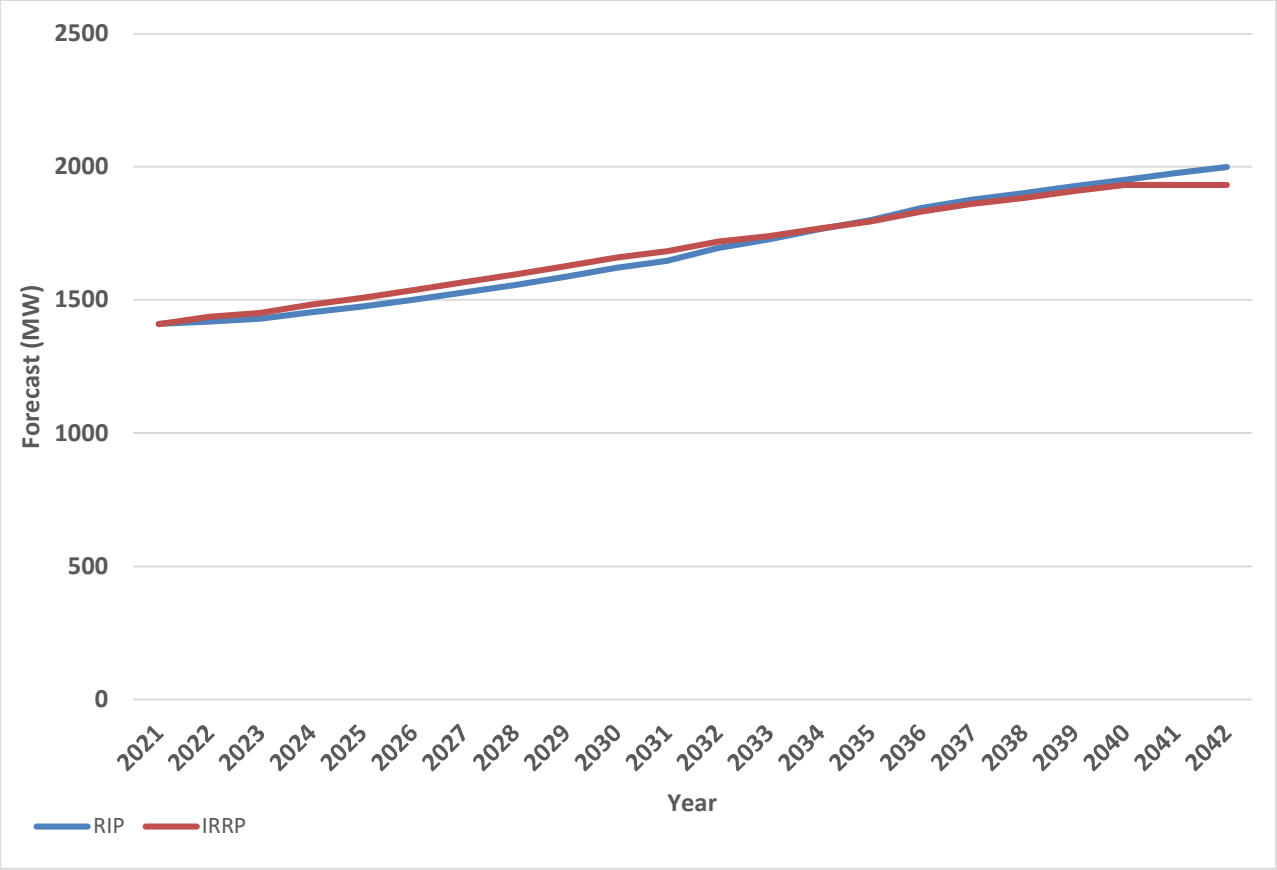


Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast

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-day LTR.

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 theload 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 regionalplanning 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 – A3

CLASS ENVIRONMENTAL ASSESSMENT FOR MINOR TRANSMISSION FACILITIES

Hydro One Networks Inc. & InnPower Corporation

Class Environmental Assessment for Minor Transmission Facilities
Environmental Study Report for the InnPower Municipal Transformer Station and Hydro One 230 kV Line Project
Draft Report

Stantec Architecture Ltd. March 28, 2025 | Project No. 160900977 / 160901024

Class Environmental Assessment for Minor Transmission Facilities

Environmental Study Report for the InnPower Municipal Transformer Station and Hydro One 230 kV Line Project

Final Report

March 28, 2025

Prepared for:
InnPower Corporation
7251 Yonge St.
Innisfil, ON L9S 0J3

Hydro One Networks Inc.
Environmental Services
483 Bay Street, North Tower, 12th Floor
Toronto, ON M5G 2P5

Prepared by:
Stantec Consulting Ltd.
100-300 Hagey Boulevard
Waterloo, ON, N2L 0A4

Project Number:
160900977 / 160901024

Stantec

Limitations and Sign-off

The conclusions in the Report titled Class Environmental Assessment for Transmission Facilities - Environmental Study Report for the Proposed InnPower Municipal Transformer Station and Hydro One 230 kV Line Project are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

Stantec has assumed all information received from InnPower Corporation (the "Client") and third parties in the preparation of the Report to be correct. While Stantec has exercised a customary level of judgment or due diligence in the use of such information, Stantec assumes no responsibility for the consequences of any error or omission contained therein.

This Report is intended solely for use by the Client in accordance with Stantec's contract with the Client. While the Report may be provided to applicable authorities having jurisdiction and others for whom the Client is responsible, Stantec does not warrant the services to any third party. The report may not be relied upon by any other party without the express written consent of Stantec, which may be withheld at Stantec's discretion.

Prepared by: Choo, Zhi Xuan Clarice Digitally signed by Choo, Zhi Xuan Clarice Date: 2025.03.31 13:48:38 -04'00'
Signature

Clarice Choo
Printed Name and Title

Digitally signed by Zeldin, Dominique Date: 2025.03.31 15:04:19 -04'00'
Signature

Dominique Zeldin
Printed Name and Title

Reviewed by: Digitally signed by Frith, Lindsay Date: 2025.03.31 12:22:41 -04'00'
Signature

Lindsay Frith, B.E.S., MCIP, RPP
Printed Name and Title

Approved by: Digitally signed by Greener, Leslie Date: 2025.03.31 14:57:34 -04'00'
Signature

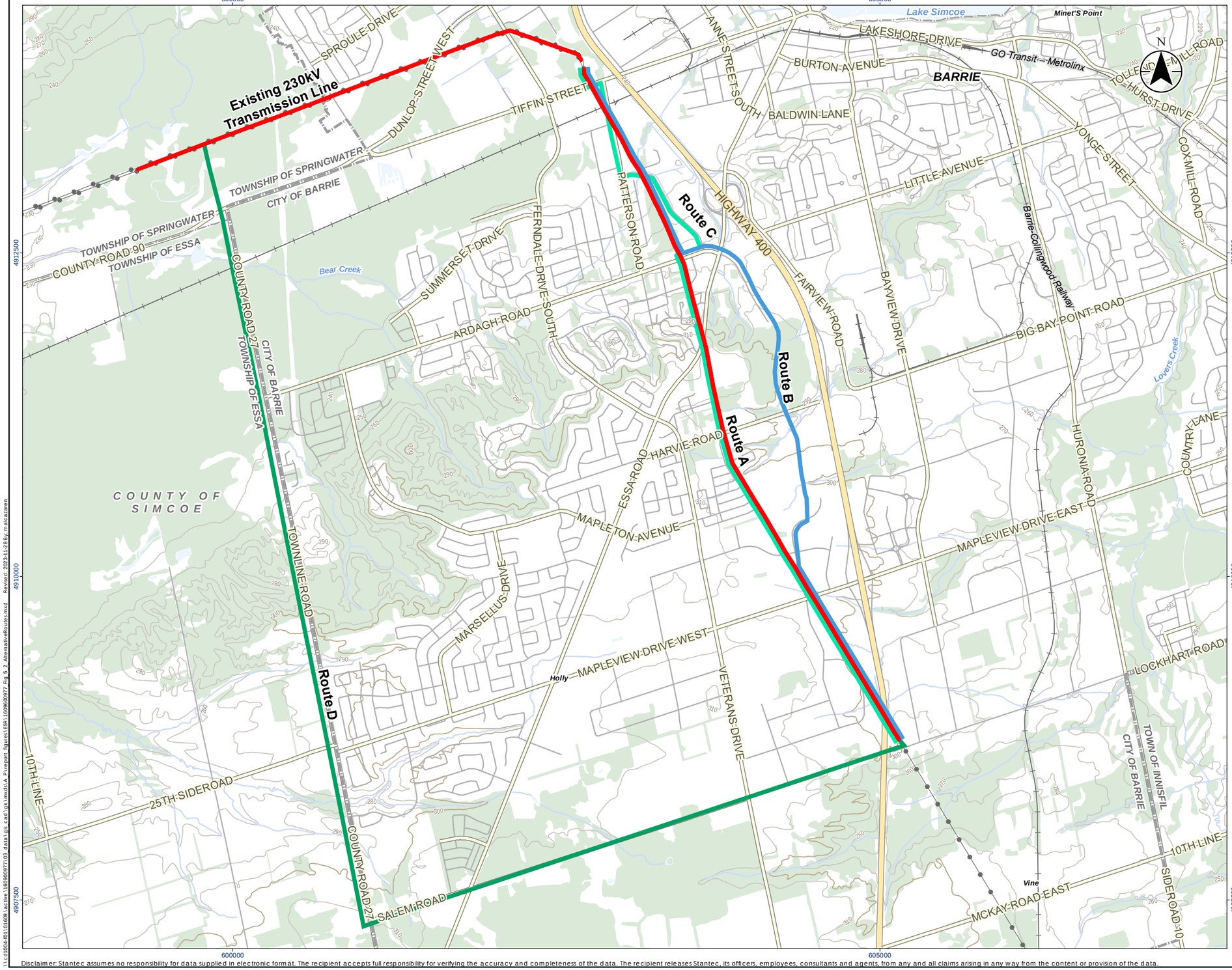
Leslie Greener, EP
Printed Name and Title

Executive Summary

The proposed InnPower Municipal Transformer Station and Hydro One 230 kV Line Project ("the Project") is subject to the Class Environmental Assessment for Minor Transmission Facilities (Class EA for MTF) (Hydro One 2022[1]), an approved planning process under the *Environmental Assessment Act* (*EA Act*) designed for proponents to characterize the existing environment, assess potential environmental effects and mitigation, identify and evaluate alternatives, conduct consultation and document study findings. The draft ESR has been prepared in accordance with the requirements of the *EA Act* and describes the Class EA process undertaken for the proposed Project.

At the outset of the Class EA, the Project Study Area and various Local Study Areas (for each alternative) were identified as a mechanism to assess potential natural environment, socio-economic environment, technical and cultural constraints and potential effects associated with each of the four Route Alternatives and their corresponding variations identified (Figure E.1) for the transmission line portion of the Project. Similarly, a site selection study was performed to assess the constraints and potential effects of each of the three Site Alternatives (Figure E.2) for the municipal transmission station portion of the Project.

[1] The Notice of Commencement was issued under the Class EA for MTF , therefore the Project will continue to be assessed in accordance with the Class EA for MTF. It is acknowledged that the Class EA for MTF has since been amended to the Class Environmental Assessment for Transmission Facilities (Hydro 2024).



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Legend

- Route A
- Route B
- Route C
- Route D
- Topographic Contour (m AMSL)
- Highway
- Major Road
- Minor Road
- Hydro Line
- Railway
- Watercourse
- Waterbody
- Wooded Area

0 1 2 km

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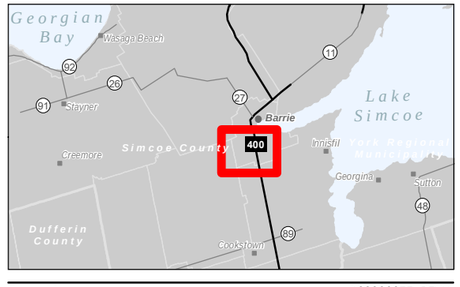

Project Location
City of Barrie/
Town of Innisfil

160900977 REVA
Prepared by MDA on 2023-11-28

Client/Project
INNPOWER CORPORATION
INNPOWER HYDRO ONE ESR

Figure No.
E-1

Title
Route Alternatives and Local Study Area

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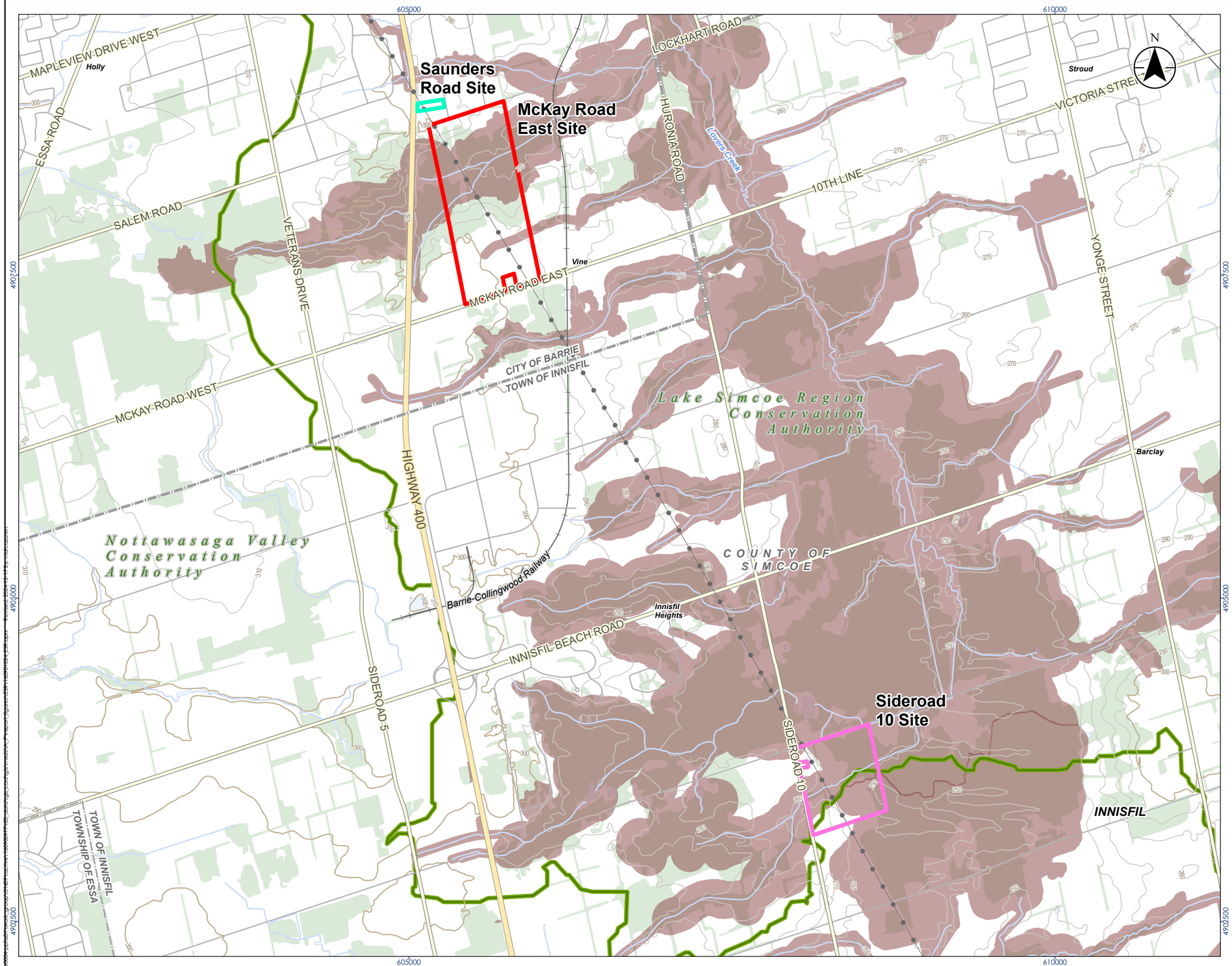

Stantec

Legend

- Saunders Road Site
- McKay Road East Site
- Sideroad 10 Site
- Topographic Contour (m ASML)
- Highway
- Major Road
- Minor Road
- Hydro Line
- Railway
- Watercourse
- Conservation Authority Administrative Boundary
- Regulation Limit (LSRCA, NVCA)
- Waterbody
- Wooded Area
- Municipal Boundary
- Municipal Boundary, Lower

0 1 2 km

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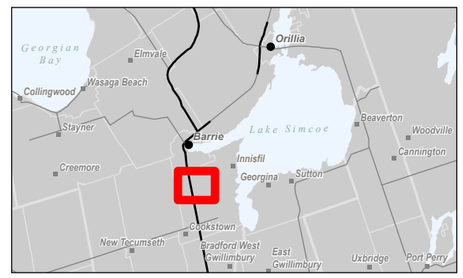

Project Location
City of Barrie/
Town of Innisfil

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Client/Project
INNPOWER CORPORATION
INNPOWER HYDRO ONE ESR

Figure No.
E-2

Title
Site Alternatives and Local Study Area

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For its comparative evaluation procedure, the Class EA for MTF process for the proposed Project utilized a multi-criteria decision-making analysis to assist in selecting the preferred alternative. Resources were identified, and data obtained from literature reviews, reports and technical memos commissioned by Hydro One, online databases, mapping, consultation, and field surveys.

The Class EA for MTF process for the proposed Project included a characterization of the existing environment through literature reviews, reports and technical memos commissioned by Hydro One and InnPower, online databases, mapping, consultation and field surveys. This research informed an assessment of the Route Alternatives and variations using a multi-criteria decision making analysis to evaluate the alternatives and select the preferred municipal transmission station (TS) and transmission line (TL) alternatives, namely the Saunders Road Site InnPower TS alternative and Route A TL alternative.

Overall for the proposed TS site, as the Saunders Road Site InnPower TS alternative is located in an existing industrial area, there are no anticipated conflicts with land use designations or impacts to terrestrial and aquatic natural heritage, and cultural heritage. The proposed TS is also predicted to operate in compliance with the applicable noise limits for all periods and noise mitigation is not anticipated for the Project. For the proposed TL site, Route A is preferred as it utilizes the existing 115kV corridor, hence eliminating the need to develop a new 'greenfield' overhead line. There is little to no anticipated conflicts with land use designations, with negligible impacts to terrestrial and aquatic natural heritage, and cultural heritage. Additionally, Route A does not cross provincially significant wetlands (PSW) nor areas of natural and scientific interest (ANSI).

Potential environmental effects resulting from the proposed Project have been identified and avoidance and/or mitigation measures have been proposed accordingly. Based on information collected to date, no substantial net adverse environmental effects were identified.

Hydro One is providing a 30-day public review period, from April 4, 2025 to May 5, 2025, to allow for review and comment on this draft ESR. Written comments or questions regarding the draft ESR are to be submitted to Hydro One no later than 5 p.m. May 5, 2025, and must be addressed to:

> Adam Haulena, Environmental Planner, Hydro One Networks Inc.
> 483 Bay Street, North Tower, 14th Floor, Toronto, ON, M5G 2P5
> Phone: 1-877-345-6799 (community relations hotline)
> Email: Community.Relations@HydroOne.com

The draft ESR can be viewed electronically on Hydro One's website at InnPower Project (hydroone.com). A paper copy of the draft ESR is also available to sign out at the following location, during operating hours:

Barrie Public Library - Holly Library, 555 Essa Rd Unit #17 Barrie, ON L4N 6A9

Hydro One has provided electronic, and if requested, will provide hard copies of the draft ESR to Indigenous communities engaged throughout the Class for MTF process (see Section 3.3).

On March 31, 2025, the Notice of Completion of draft ESR was distributed to all interested parties including Indigenous communities, municipal, provincial and federal government officials and agencies, potentially affected and interested persons, and interest groups presented in Section 3. The Notice was published on the Project website InnPower Project (hydroone.com).

Comments received will be addressed and documented in the final ESR as required by the Class EA for MTF process. Hydro One will make best efforts to respond and resolve issues raised by concerned parties during the public review period. Following completion of the review period, the ESR will be finalized for the proposed Project in accordance with the Class EA, and the final ESR will be filed with the Ministry of the Environment, Conservation and Parks (MECP). The Project will then be considered approved and may proceed as outlined in the ESR.

A request may be made to the MECP for an order requiring a higher level of study (i.e., requiring comprehensive EA approval before being able to proceed), or that conditions be imposed (e.g., require further studies), only on the grounds that the requested order may prevent, mitigate or remedy adverse effects on constitutionally protected Aboriginal and treaty rights. The MECP will not consider requests on other grounds.

Requests should include the requester's contact information and full name, as well as specify what kind of order is being requested (request for conditions or comprehensive EA), how an order may prevent, mitigate or remedy potential adverse effects on Aboriginal and treaty rights, and any information in support of the statements in the request. This will allow an efficient review of the request. The request should be sent in writing or email to:

Minister of the Environment, Conservation and Parks
777 Bay Street, 5th Floor
Toronto ON M7A 2J3
Email: minister.mecp@ontario.ca

Environmental Assessment Branch
Ministry of Environment, Conservation and Parks
135 St. Clair Ave. W, 1st Floor
Toronto ON, M4V 1P5
Email: EABDirector@ontario.ca

Requests should also be copied to Hydro One as per the contact information provided above.

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C.5 Acoustic Assessment Report

Acronyms / Abbreviations

AA	Archaeological Assessment
ANSI	Area of Natural and Scientific Interest
BATU	Barrie Area Transmission Upgrade
BCRY	Barrie-Collingwood Railway
Class EA for MTF	Class Environmental Assessment for Minor Transmission Facilities
CLI	Canada Land Inventory
CN Railway	Canadian National Railway
COH	Community Open House
CPKC Railway	Canadian Pacific and Kansas City South Railway
DBH	Diameter at Breast Height
EA	Environmental Assessment
EA Act	*Environmental Assessment Act*
EASR	Environmental Activity and Sector Registry
ECCC	Environment and Climate Change Canada
EMF	Electric and Magnetic Fields
ESC	Erosion and Sediment Control
ESR	Environmental Study Report
HBC	Heritage Baptist Church
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IESO	Independent Electricity System Operator
IO	Infrastructure Ontario
IRRP	Integrated Regional Resource Plan
KHF	Key Hydrological Features
KNHF	Key Natural Heritage Features
LSA	Local Study Area
LSRCA	Lake Simcoe Region Conservation Authority
MCM	Ministry of Citizenship and Multiculturalism
MECP	Ministry of the Environment, Conservation and Parks
MMAH	Ministry of Municipal Affairs and Housing

MNO	Métis Nation of Ontario
MNR	Ministry of Natural Resources
MP	Member of Parliament
MPP	Member of Provincial Parliament
MTF	Minor Transmission Facilities
MTO	Ministry of Transportation
MW	Megawatts
NOC	Notice of Commencement
NVCA	Nottawasaga Valley Conservation Authority
OP	Official Plan
O. Reg.	Ontario Regulation
PPS	Provincial Policy Statement
PSA	Project Study Area
PSW	Provincially Significant Wetlands
PTTW	Permit to Take Water
ROW	Right-of-Way
SAR	Species at Risk
SARA	*Species at Risk Act*
SOCC	Species of Conservation Concern
TL	Transmission Line
TS	Transmission Station

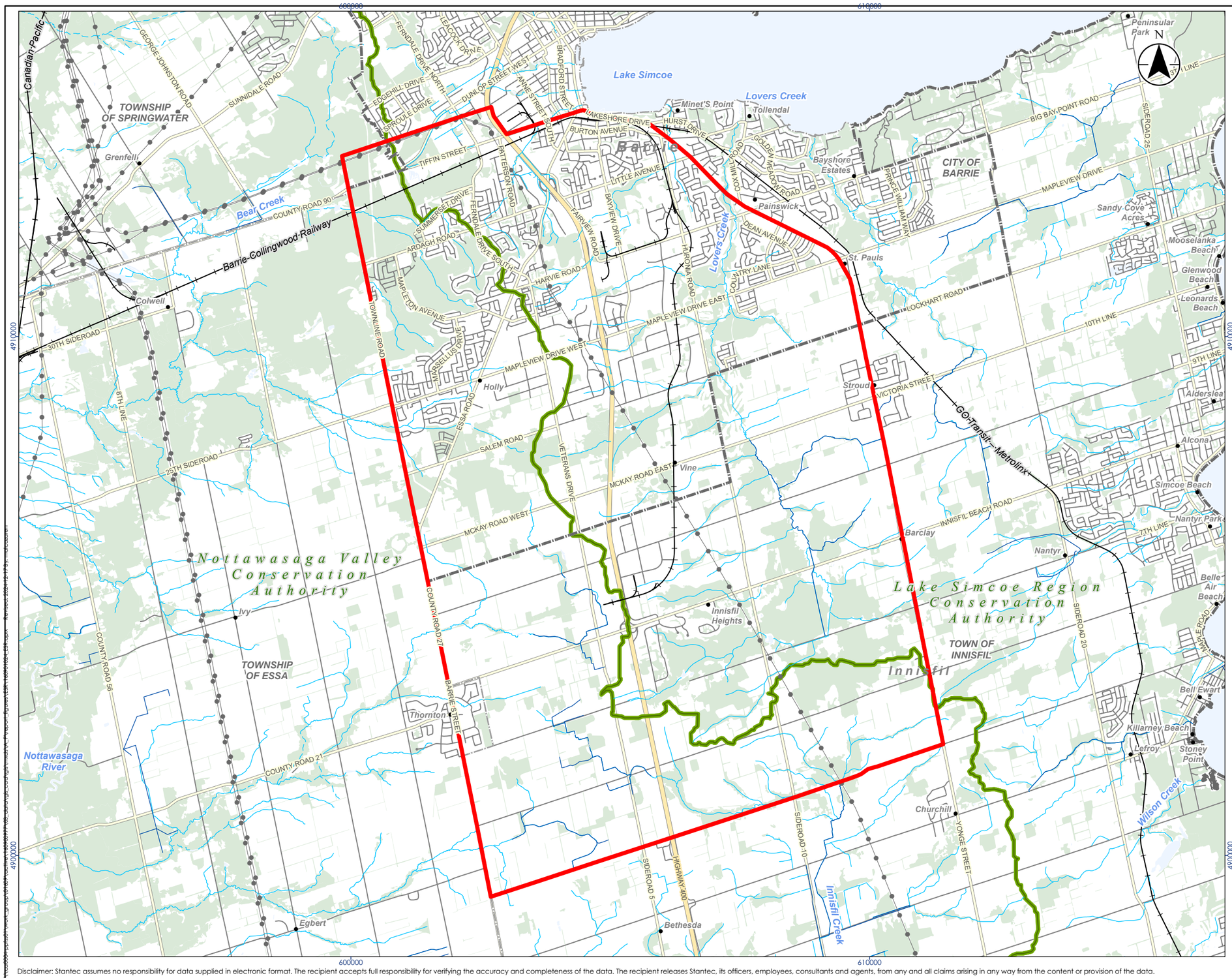
1 Introduction

InnPower Corporation (InnPower) is proposing to design, construct, energize and operate a new 230 kilovolt (kV)/27.6 kV Jones-style municipal Transformer Station (TS) in the City of Barrie, Ontario, Canada. To support the new TS, Hydro One Networks Inc. (Hydro One) is proposing to upgrade approximately 6 kilometres (km) of transmission line (TL) between Barrie Transformer Station (TS) and the proposed InnPower TS from 115 kV to a new, double-circuit 230 kV TL. The purpose of the new TS and TL upgrade ("the Project") is to address the anticipated load growth in the Town of Innisfil and the City of Barrie.

The Project is subject to the Class Environmental Assessment for Minor Transmission Facilities (Class EA for MTF) (Hydro One 2022[2]) in accordance with the Ontario *Environmental Assessment Act* (EA Act). The Class EA for MTF is a streamlined process utilized by projects that have predictable environmental effects that can likely be mitigated and can be planned and constructed in accordance with a common process. This draft Environmental Study Report (ESR) has been prepared in accordance with the requirements of the EA Act and describes the Class EA for MTF process undertaken for the proposed Project and:

- Summarizes the existing conditions in the Project Study Area (PSA) and Local Study Area (LSA).
- Documents the notifications to, and consultation undertaken with Indigenous communities, government agencies, municipal staff and elected officials, interest groups and members of the public about the Project.
- Documents the site identification and evaluation process conducted to select the preferred site alternative for the municipal TS portion of the Project.
- Documents the route identification and evaluation process conducted to select the preferred route alternative for the TL portion of the Project.
- Identifies potential environmental effects associated with the Project.
- Identifies potential mitigation measures to address these potential environmental effects.

[2] The Notice of Commencement was issued under the Class EA for MTF, therefore the Project will continue to be assessed in accordance with the Class EA for MTF. It is acknowledged that the Class EA for MTF has since been amended to the Class Environmental Assessment for Transmission Facilities (Hydro 2024).



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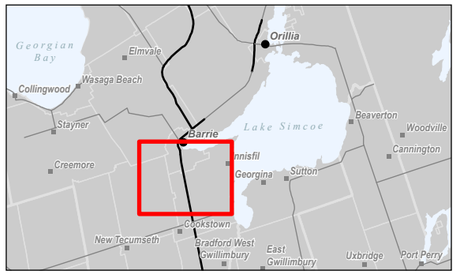

Project Location
City of Barrie/
Town of Innisfil

1609600977 REVA
Prepared by MDA on 2024-12-17

Client/Project
INNPOWER CORPORATION
INNPOWER HYDRO ONE ESR

Figure No.
1.1

Title
Project Location

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1.1 Need for the Undertaking

The Project is required to address the load growth in Innisfil and southern portion of the City of Barrie. The City of Barrie has forecasted a significant increase in population from 155,137 in 2022 to 298,000 in 2051 (City of Barrie 2022). Similarly, the Town of Innisfil anticipates a total increase in population from approximately 45,000 in 2021 to over 84,000 in 2051 (County of Simcoe 2021). The resulting demand growth in the Innisfil area continues to increase with InnPower's demand forecasted to reach 113 MW by 2029 (IESO 2022), which exceeds current generation capabilities. Hence, capacity limitations are forecasted at the existing TSs in the near/mid-term for the Barrie/Innisfil sub-region (IESO 2022).

Coupled with end-of-life refurbishments for sections of the existing circuits, new infrastructure is needed to increase the load meeting capability of the area. The purpose of the new TS and upgraded TL is to increase the overall capacity of the electrical generation and transmission system within the City of Barrie and Town of Innisfil.

The required in-service date for the Project is late 2027 to address the specified bulk system electricity needs. To meet the energy needs of the region as quickly as possible, InnPower and Hydro One are seeking opportunities to advance the in-service date.

1.2 Description of the Undertaking

The proposed Project will involve the installation of a new 230 kV/27.6 kV Jones-style TS and an upgraded 230 kV TL connecting InnPower's proposed TS and Hydro One's existing Barrie TS.

The proposed TS portion of the Project will be situated on property owned by InnPower, located north of Saunders Road and Lockhart Road in the City of Barrie, Ontario. Based on the preliminary design, the proposed TS will require an area of approximately 130 metres (m) by 70 m, including infrastructure, fencing and a control building. The proposed TL upgrade portion of the Project spans approximately 6 km and is located within a developed area of the City of Barrie that includes residential areas, commercial areas, and green spaces.

Upon the successful completion of the Class EA for MTF process and receipt of subsequent required approvals, construction could begin as early as 2025 with a planned in-service date of late 2027[3].

1.3 Alternatives to the Undertaking

The Class EA for MTF process requires identification and evaluation of alternatives to the undertaking (i.e., the proposed Project). "Alternatives to" the undertaking are functionally different approaches to addressing the need for the undertaking.

Alternatives to the undertaking must be reasonable from a technical, economic and environmental perspective and must fall within the mandate of the proponent. It is understood that companies whose

[3] Milestone timelines are approximate and are subject to change depending on outcomes of the planning and approvals process.

operating licences (i.e., as granted by the Ontario Energy Board) are limited to assessment of transmission alternatives cannot, for example, assess generation as an alternative to transmission facilities.

Four alternatives to the undertaking were considered:

- Alternative 1: Do Nothing
- Alternative 2: Transmission Alternatives
- Alternative 3: Additional Storage Alternatives
- Alternative 4: Transmission Infrastructure and Transformer Station

1.3.1 Alternative 1: Do Nothing

The “Do Nothing” Alternative must be considered in the Class EA process per Section 3.2.1 of the Hydro One Class EA for MTF Document (Hydro One 2022).

Due to the anticipated increase in population and demand forecast for electricity in the City of Barrie and Town of Innisfil area, the “Do Nothing” Alternative would result in an inability to reliably supply the forecasted load growth. Furthermore, the “Do Nothing” Alternative would limit resources and bulk facilities in the region from operating efficiently for local and system needs. Therefore, the “Do Nothing” Alternative is not considered to be a feasible alternative.

1.3.2 Alternative 2: Transmission Alternatives

Transmission alternatives at the existing Barrie TS were assessed as part of the IESO May 2022 Integrated Regional Resource Plan (IRRP) for the Barrie/Innisfil region (IESO 2022), as one of the limitations is the supply constraint on the distribution level at the 44 kV feeder starting in 2025. The following transmission alternatives were explored but screened out as they do not fully meet the increasing energy needs of the Barrie/Innisfil region:

- Additional 44 kV feeder position from Barrie TS at a cost of $20 million.
    - This solution would provide up to 25 MW of supply which would only be sufficient until 2027. Another solution would have to be implemented for energy needs beyond 2027 which would incur additional costs.
- Load the existing 44 kV supply feeders beyond normal capacity at a cost of $8 million.
    - This would increase the feeder supply capacity by a total of 20 MW. However, this solution is similarly not enough to meet energy needs beyond 2027.

1.3.3 Alternative 3: Additional Storage Alternatives

In terms of non-wires alternatives[4] options, energy storage was assessed in the IRRP (IESO 2022). However, the IRRP estimated that constructing an 81 MW battery storage would cost $130 million (almost three times that of a new 230 kV/27.6 kV TS which was estimated at $48 million) and supply capacity constraints at the 44 kV feeder level would still be a limitation starting in 2025. Due to the financial considerations of this option as well as the supply capacity constraints in the near future, this alternative was not considered viable.

1.3.4 Alternative 4: Upgrade Existing Transmission Infrastructure and Construct a New Transformer Station

The alternative recommended in the IRRP (IESO 2022) as capable of meeting the energy demand growth is to construct a new 230kV/27.6 kV transformer substation which would connect to upgraded circuits once the Barrie Area Transmission Upgrade (BATU) reinforcements are in service. Part of the BATU project involves upgrading existing circuits to new 230 kV circuits. For these reasons, this alternative has been carried forward for consideration and has been recommended in the report as the most feasible and cost-effective solution in meeting the community's growing energy needs while aligning with the area's infrastructural plans.

1.4 Approval Process and Regulatory Requirements

This section outlines the approval process required under the Class EA for MTF process as well as other regulatory requirements.

1.4.1 Class Environmental Assessment Process

The ESR was prepared in accordance with the Class EA for MTF (Hydro One 2022), which is an approved process under the *EA Act*. Components of the process include:

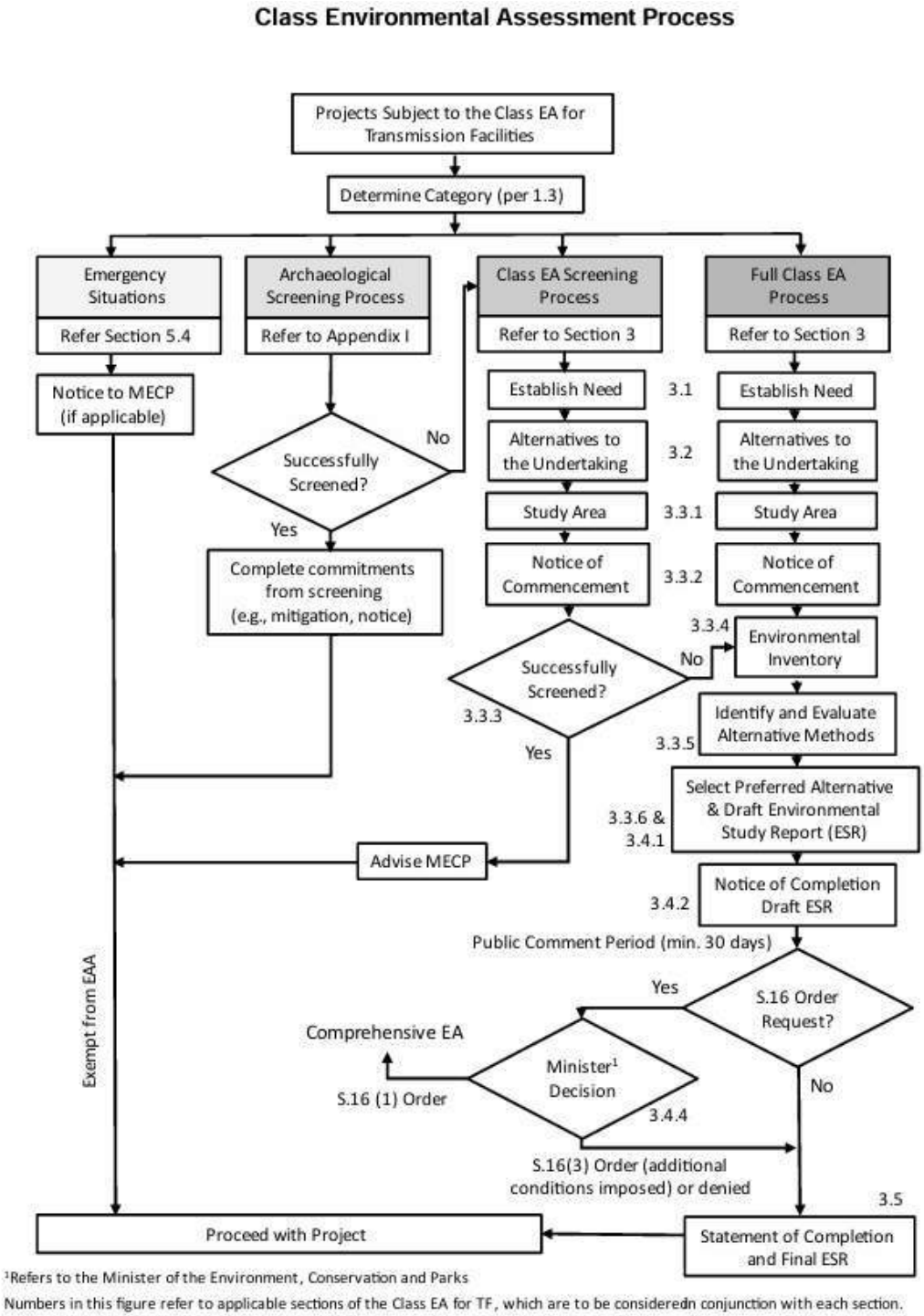
1. Establish need (Section 1.1)
2. Identify and evaluate alternatives to the Project (Section 1.3)
3. Define the Study Area (Section 2)
4. Issue Notice of Commencement (Section 3.1)
5. Conduct an environmental inventory (Section 4)
6. Identify and evaluate alternative methods (Section 5)
7. Select preferred alternative method (Section 5.2)
8. Prepare the draft ESR

[4] Non-wires alternatives are measures implemented or installed to reduce the net peak demand to maintain loading within the system's existing load meeting capability and include local utility scale generation, distributed energy resources, or conservation and demand management (IESO 2022)

9. Issue Notice of Completion and commence draft ESR review period
10. File final ESR and Statement of Completion with the Ministry of Environment, Conservation and Parks (MECP) and proceed with the Project
11. Conduct consultation throughout the EA process (Section 3)

The Class EA for MTF process is illustrated in Figure 1.2

Figure 1.2 The Class EA for MTF Process (Hydro One 2022)



The Class EA for MTF applies to Category B[5] projects as stated in the Guide to EA Requirements for Electricity Projects and Class EA for MTF Document (Hydro One 2022). The criteria that triggered the Class EA for this Project is from Part A.2 of the Guide to EA Requirements (MECP 2024), the class of undertaking subject to the Class EA includes:

- Transmission lines that are more than 2 km in length and are capable of operating at greater than or equal to 115 kV.
- Transformer stations that are greater than or equal to 115 kV.

The Class EA for MTF process includes establishing new lines/stations as well as the refurbishing or expansion of existing lines/stations. The Project includes the upgrade of approximately 6 km of TL from 115kV to 230 kV to connect InnPower's proposed 230 kV TS and Hydro One's existing Barrie TS. As such, the Project is subject the Full Class EA process.

Hydro One and InnPower issued notifications of the draft ESR review period to municipal, provincial, and federal government officials and agencies, Indigenous communities, and potentially affected and interested persons and interest groups. The draft ESR was made available for public review and comment for a minimum period of 30 calendar days, from [**NTD: review period dates to be added to the final ESR**].

As outlined by recent provincial government amendments, a request may be made to the MECP for an order requiring a higher level of study (i.e., requiring a comprehensive EA approval before being able to proceed). A request may also be submitted that conditions be imposed (e.g., require further studies), only on the grounds that the requested order may prevent, mitigate or remedy adverse impacts on constitutionally protected Aboriginal and treaty rights. The MECP will not consider requests on other grounds.

Requests should include the requester's contact information, as well as specify what kind of order is being requested (request for conditions or a comprehensive EA), how an order may prevent, mitigate or remedy potential adverse impacts on Aboriginal and treaty rights, and any information in support of the statements in the request. The request should be sent in writing or by email to MECP. A copy of the request and any supporting information must also be forwarded to Hydro One.

If no requests are received by MECP during the 30-day period, the Project may proceed to detailed design, permitting and construction.

A copy of the final ESR will be placed on the Hydro One Project website, as well as provided to the Environmental Assessment Branch and the appropriate Regional EA Coordinator at MECP for filing. Once the final ESR and the Statement of Completion have been filed with MECP, the proposed Project will be considered acceptable and may proceed as outlined in the final ESR.

[5] Category B projects are those which have potential environmental effects that can likely be mitigated (MECP, 2011)

1.4.2 Other Permits, Licenses, and Approvals

In addition to meeting the Class EA for MTF requirements, there are a number of potential permits and approvals that are required under federal, provincial and municipal legislation (see Table 1.1). InnPower and/or Hydro One will contact the appropriate regulatory agencies to confirm that the Project meets applicable requirements and that approvals are obtained as necessary. The proposed Project does not trigger a federal EA under the *Impact Assessment Act, 2019*.

Table 1.1 List of Potential Permits/Approvals

Permit/Approval	Responsible Agency	Potential Trigger
Federal		
Species at Risk Permit (*Species at Risk Act*)	Environment and Climate Change Canada	• Activities that could affect species at risk listed on Schedule 1 of the act as extirpated, endangered or threatened and which contravene with the Act's general or critical habitat prohibitions
Permits under the *Fisheries Act* (Request for Review/Authorization, and Authorization(s) Concerning Fish and Fish Habitat Protection Regulations)	Fisheries and Oceans Canada	• Watercourse crossings
Aeronautical Assessment	Transport Canada	• Structures that are obstacles to air navigation, such as transmission lines
Land Use Assessment Permit	NAV Canada	• Construction of new transmission lines
Provincial		
Class Environmental Assessment (Ontario *Environmental Assessment Act*)	MECP	• As per O. Reg. 50/24 *Part II.3 Projects – Designations and Exemptions*, • Transformer stations (≥ 115 kV), and/or • Transmission lines (≥ 115 kV and > 2 km) • Upgrade in voltage
Ministry of Citizenship and Multiculturalism (MCM) confirmation of review (Cultural heritage resources)	MCM	• Activities that may affect cultural heritage resources and/or cultural heritage landscapes
Archaeology Clearance Letter	MCM	• Activities that may affect archaeological resources
Environmental Compliance Approval – Industrial Sewage	MECP	• Stormwater management and the secondary containment for the TS
Environmental Activity and Sector Registry (EASR) – Noise **OR** Environmental Compliance Approval – Air/Noise	MECP	• Potential noise emissions from TS

Permit/Approval	Responsible Agency	Potential Trigger
Permit or registration under Ontario ESA	MECP	• Activities that affect a listed wildlife species
Wildlife Scientific Collectors Permit (*Fish and Wildlife Conservation Act*)	Ministry of Natural Resources (MNR)	• Required should wildlife need to be relocated during construction
Encroachment Permit (Ontario *Public Transportation and Highway Improvement Act*)	Ministry of Transportation (MTO)	• Any installation or works upon, under, or within the limits of a provincial highway ROW
Building and Land Use Permit (Ontario *Public Transportation and Highway Improvement Act*)	MTO	• The construction of a structure within an area within MTO permit control
Leave to Construct Approval under Section 92 of the *Ontario Energy Board Act*	Ontario Energy Board	• Construction, expansion, or reinforcement of electricity transmission and distribution lines or interconnections
Permit for Development, Interference with Wetlands and Alteration of Shoreline and Watercourses (O. Reg. 41/24 *Prohibited Activities, Exemptions and Permits*)	Lake Simcoe Region Conservation Authority (LSRCA)	• Development within an area regulated by LSRCA
Designated Substances Survey and Assessment Report under O. Reg. 406/09 *On-Site and Excess Soil Management*	MECP	• Demolition or alteration (e.g., partial removal) of existing structure on InnPower property
Environmental Activity and Sector Registry Registration or Permit to Take Water	MECP	• Dewatering activities (in the case of dewatering activities over 400,000 L/day, PTTW application is required)
Municipal		
Building Permit	City of Barrie	• New buildings within the City of Barrie
Screening under Section 59 of the *Clean Water Act*	City of Barrie	• New buildings located within a Well Head Protection Area
Right-of-Way Activity Permit	City of Barrie	• Works occurring on or across City of Barrie property (e.g., roadways, curbs, boulevards, sidewalks, parklands, open space, public walkways and environmentally protected lands)
Sewer Use Report and Discharge Agreement under the Sewer Use By-law (2021-002)	City of Barrie	• Discharge of wastewater or groundwater
Cultural Heritage Report Review	Heritage Barrie (City of Barrie)	• Activities that may affect cultural heritage resources and/or cultural heritage landscapes

Permit/Approval	Responsible Agency	Potential Trigger
Demolition Permit **OR** Alteration Permit	City of Barrie	• Demolition or alteration (e.g., partial removal) of existing structure on InnPower property
Site Plan Approval	City of Barrie	• New buildings within the City of Barrie
Other		
Railway Right-of-Way (ROW)	Railways	• Works within the ROWs of rail companies such as the Barrie-Collingwood Railway (BCRY)
Utility Crossing	Utilities	• Works within the ROWs of utility companies such as Enbridge

In the event that other permits are identified as required, InnPower and/or Hydro One will work with the relevant regulator(s) to be in compliance.

2 Project Study Area

The Project Study Area (PSA) was delineated to encompass a preliminary area in which alternative methods could be identified to address the need for the undertaking. The PSA is bounded generally by Hydro One's existing transmission corridor and Tiffin Street to the north, 5th Line to the south, Highway 27 to the west and Highway 11 (i.e., Yonge Street) to the east (Figure 1.1).

The PSA boundaries were established following a review of potential siting options for Project infrastructure and existing natural environment, socio-economic, and technical constraints to identify the potential effects associated with the Project.

Within the PSA, the Local Study Area (LSA) represents the area required to carry out all physical works and activities either directly for infrastructure or for associated Project uses (e.g., laydown, access, grading and drainage) and is defined as the Project footprint plus a 120 m buffer. Each alternative method (refer to Section 5) has a distinct LSA.

Site specific investigations were carried out for the LSA of the preferred alternative (Section 5.3). For the various technical assessments, discipline-specific Assessment Areas were selected in consideration of the potential environmental impacts that could be reasonably predicted given the current land uses in the area and the sensitivity of the adjacent natural heritage features. Professional judgment and previous experience with potential impacts from similar developments was used to determine the spatial extent of potential environmental impacts from the Project and to designate appropriate discipline-specific study areas (see Table 2.1 and Section 7.1).

Table 2.1 Discipline-specific Assessment Areas

Technical Discipline	Assessment Area
Terrestrial and Aquatic Ecosystems	A 120 m buffer on the Project Footprint for the preferred alternative
Noise	A 500 m buffer on the preferred TS site
Land Use	Project Footprint for the preferred alternative
Cultural Heritage Resources	A 50 m buffer on the Project Footprint for the preferred alternative
Archaeology	A 120 m buffer on the Project Footprint for the preferred alternative

3 Consultation

Consultation is an important component of the Class EA for MTF process as it provides those who may be interested in, or potentially affected by, the proposed Project with timely and adequate information and opportunities to participate in the planning process. Consultation also allows the proponent to gain information and knowledge related to social, cultural, economic and environmental considerations of direct relevance to the proposed Project, as well as the means to inform and explain the approach to, and value of, the proposed Project. The key principles that have guided Hydro One and InnPower's approach to communication and consultation include:

- Early, ongoing and timely communication and engagement.
- An open, transparent, and flexible engagement process.
- Clear Project information with the opportunities for Indigenous communities, community officials, and Project stakeholders to comment, ask questions and raise concerns.
- Ongoing opportunities for interested parties to learn about and provide meaningful input on the proposed Project.
- Full and fair considerations and documentation of all input received during the consultation process and incorporation of such input, where feasible and reasonable, into Project decision-making.

The Project Rightsholder and Stakeholder List is provided in Appendix B.1.

To facilitate comprehensive, transparent and adequate consultation and engagement, an integrated multi-channel communication program was implemented, consisting of:

- Letters and emails to notify interested parties and provide updates on the Project.
- Community Open Houses (COHs), which provided opportunities for interested parties to discuss with the InnPower/Hydro One Project team, address questions and provide comments.
- Establishment of a Project Rightsholder and Stakeholder List, through which interested parties can receive Project notifications and updates via email or regular post.
- Establishment and maintenance of a Project website on which Project information is published regularly (https://www.hydroone.com/about/corporate-information/major-projects/innpower).

The results of the consultation program are summarized in the sections below, with a visual timeline provided in Figure 3.1. Copies of consultation materials, such as notices and notification letters as well as COH Summary Reports are provided in Appendix B.2.

A high-level overview of the consultation timeline is outlined in and further explained in the subsequent sections below.

Figure 3.1 Consultation Timeline

3.1 Notice of Commencement

The Notice of Commencement (NOC) introduced the Project and provided details on the need, description and study area. It also referred to the Project website and provided contact information for feedback.

Copies of the NOC and notice of COH held in July 2023 were distributed as follows:

- Email notices to elected officials, government agencies and officials, interest groups, businesses, utilities, community associations and school boards between July 7 and 14, 2023 as per the Project Stakeholder List (Appendix B.1)
- Prior to Crown delegation, early engagement email notices were sent to Beausoleil First Nation, Chippewas of Georgina Island First Nation and Chippewas of Rama First Nation on June 30, 2023[6].
- Upon Hydro One receiving Crown delegation for the procedural aspects of the Duty to Consult, Hydro One sent notices to additional communities that were identified by the Crown on September 9, 2023. This included the Williams Treaties Nations, Métis Nation of Ontario, and Kawartha Nishnawbe First Nation. A notice went to Nation huronne-wendat for archaeology interests. Published in the Barrie Advance newspaper on July 13 and 20, 2023, and in the Innisfil Journal on July 20, 2023
- Published on Hydro One website (https://www.hydroone.com/about/corporate-information/major-projects/innpower)
- Delivered via Canada Post addressed mail to 1,200 property or business owners within 1,000 m of the Project

3.2 Community Open Houses

InnPower and Hydro One held COHs for the Project on July 26, 2023, and November 5, 2024. The purpose of the COHs was to provide the public with an opportunity to engage with InnPower and Hydro One directly and to provide insight on the Project.

Refer to Appendix B.2 for summaries of the COHs held and the materials presented.

3.2.1 Community Open House #1

As a part of the NOC, rightsholders and stakeholders were informed of the first COH being held on July 26, 2023.

[6] Indigenous communities identified during the preliminary stage. The list of Indigenous communities was expanded upon the Ministry of Energy's direction on August 25, 2023, and were included in all subsequent notifications.

The information presented in the COH included the need for the Project, an overview of the Project, including the proposed Project area, the Class EA process, corridor details, a sample municipal transformer station, future engagement for public stakeholders and Indigenous communities, Project milestones, and health and safety. Key questions received and InnPower and Hydro One's responses are provided in Table 3.1.

Table 3.1 COH#1 Key Questions Received and Responses

Topic of Questions / Comments	Response
Concerns about the size and location of the transmission towers	This information was not available at the time as the Project was still in early planning stages. The size and location of the towers has now been shared with the public at the second COH and on Hydro One's website.
Concerns about the potential impacts of electric and magnetic fields (EMF) on the public	Hydro One met with Discovery Daycare which raised concerns about the potential impacts of EMF during the operational phase to provide an overview of EMF as it relates to 230kV corridors and discussed the EMF change that would occur on this line. Hydro One also shared that they are currently undertaking an EMF study and would share the results when they were available. Consultation with Discovery Daycare is ongoing, and outcomes will be captured in the Record of Consultation.
Potential impacts during construction phase	This information was not available at the time as the Project was still in early planning stages. Potential impacts during construction have been shared with the public at the second COH and on Hydro One's website.

3.2.2 Community Open House #2

A Notice of the second COH was sent to rightsholders and stakeholders with a potential interest in the Project and other interested persons in the following formats:

- Emailed to elected officials, government agencies and officials, Indigenous communities, interest groups, businesses, utilities, community associations and school boards as per the Project Rightsholder and Stakeholder List (Appendix B.1) between October 21 and October 23, 2024
- Mailed to approximately 1,200 properties and business owners within the Project Study Area on October 21, 2024
- Published within Metroland's Simcoe newsletter from October 28 – October 30, 2024, and November 1 – November 5, 2024
- Published on Hydro One website (InnPower Project [hydroone.com/about/corporate-information/major-projects/innpower])

The information presented in the COH included the need for the Project, an overview of the Project, including the proposed Project area, the Class EA process, Project milestones and next steps, corridor details, construction activities and vegetation work, future engagement for public stakeholders and Indigenous communities, and health and safety. Key questions received and InnPower and Hydro One's responses are provided in Table 3.2

Table 3.2 COH#2 Key Questions Received and Responses

Topic of Questions / Comments	Response
Concerns about what the current landscape is and how it will be altered during construction and operations, including the proposed tower locations	Hydro One provided information on their approach to corridor vegetation management, as well the siting of poles. It was noted that some pole locations have been adjusted from the previous locations.
Concerns about the potential impacts of EMF on the public	Hydro One provided information on EMF exposure limits and assessments done as part of the project. EMF levels are expected to remain well below International Commission on Non-Ionizing Radiation Protection (ICNIRP) industrial exposure limits.
Concerns about whether the Project will impact radio frequency	Hydro One noted that radio frequency is not impacted at road level.
Concerns about the proposed transmission lines and their potential impacts on Alectra transmission lines, specifically during road widening	Hydro One agreed to further discussion outside of the COH.
Inquiries about the timeframe for the Project construction and the overall schedule for the Project	Attendee was directed to the poster board on the Project timing.
Inquiries about the Project cost	Hydro One provided information about the Ontario Energy Board process and economic assessment as part of the planning process and budget disbursement.
Impacts to private property and concerns about property valuation/safety	Hydro One provided information on how to further engage with the Hydro One team regarding the property, addressed concerns about tower types and locations and addressed private property valuation issues. As the corridor exists already, impacts to property are not anticipated.

3.3 Indigenous Communities

Consultation with Indigenous communities is an important part of the engagement requirements of the Class EA for MTF process. In addition, the Crown has a constitutional duty to consult and, where appropriate, accommodate Indigenous communities when the Crown contemplates conduct that might adversely impact established or asserted Aboriginal or Treaty rights. While the legal responsibility to meet the duty to consult lies with the Crown, the Crown may delegate the day-to-day, procedural aspects of consultation to project proponents. Rights-based consultation with Indigenous communities is distinct from the requirements to consult with Indigenous communities as interested parties as part of environmental assessment processes. However, the procedural aspects of Duty to Consult can be integrated into the environmental assessment.

With respect to the Duty to Consult, InnPower and Hydro One contacted the Ministry of Energy on February 3, 2023, to understand if the Crown's Duty to Consult was triggered by the Project, and if so, which Indigenous communities need to be consulted, what level of consultation, and if they would be delegating procedural aspects of the consultation to InnPower and Hydro One. In the correspondence,

InnPower and Hydro One provided a description, location, timelines, regulatory requirements and permits of the proposed Project.

On August 25 and 28, 2023, the Ministry of Energy provided the list of Indigenous communities delegated to be consulted on the Project to Hydro One and InnPower. The letters provided the level of consultation to be low and specified roles and responsibilities of the proponent. (see Appendix B.3 for the InnPower and Hydro One inquiry letter to the Crown and the Crown Duty to Consult delegation letter):

- Alderville First Nation
- Beausoleil First Nation
- Chippewas of Rama First Nation
- Chippewas of Georgina Island First Nation
- Curve Lake First Nation
- Hiawatha First Nation
- Nation huronne-wendat (consult on archaeology interests)
- Kawartha Nishnawbe First Nation
- Georgian Bay Historic Métis Community
- Mississaugas of Scugog Island First Nation

On August 28, 2023, the Ministry of Energy sent a letter notifying all the Indigenous communities that the procedural aspects of consultation have been delegated to InnPower and Hydro One for the Project. A formal NOC was sent to all the communities listed above on June 30[7] and September 11, 2023, notifying that InnPower and Hydro One was initiating a Class EA for the Project. The NOC provided information about the Project including the need, description, location, timelines and the required regulatory and permit approvals. InnPower and Hydro One offered to meet to review the Project and welcomed the opportunity to comment, raise questions or concerns.

The Indigenous community consultation and engagement process was implemented to promote a comprehensive, transparent and meaningful consultation approach. The process included:

- Emailing notifications and provision of updates on the Project throughout the Class EA for MTF process, offering the opportunity to comment or raise questions or concerns
- Inviting Indigenous communities to the public COHs and offer to host COHs within their communities

[7] Prior to confirmation of the list of Indigenous communities to be consulted by the Ministry of Energy on August 25, 2023, the following communities were notified: Beausoleil First Nation, Chippewas of Georgina Island First Nation, and Chippewas of Rama First Nation.

- Offering to meet with Indigenous leadership and consultation representatives to discuss the Project invitation to participate in relevant fieldwork and review findings of archaeological studies conducted, and provide capacity if requested
- Establishment and maintenance of a Project website, allowing for the sharing of Project information and updates

Correspondences with the listed Indigenous communities are documented in the Record of Consultation (Appendix B.4).

3.3.1 Alderville First Nation

- Alderville First Nation responded to the NOC acknowledging receipt and informed of their interest in participation in archaeology as early as Stage 1. The Stage 1 archaeology assessment was shared for review. Hydro One invited the First Nation to the public COH in 2024 and offered to host one in the community. Hydro One will continue to inform Alderville First Nation on all archaeology engagements associated with the Project.

3.3.2 Beausoleil First Nation

- Beausoleil First Nation has not responded to the NOC, follow ups, and invitation to the public COH. Hydro One will continue to provide Project milestone updates, opportunities to comment, raise questions or concerns, and offer archaeology monitoring opportunities.

3.3.3 Chippewas of Rama First Nation

- Chippewas of Rama First Nation responded to the NOC acknowledging receipt and brought up questions regarding another Hydro One matter. Hydro One has and will continue to provide Project milestone updates to the community, including sharing the Stage 1 archaeology assessment to the First Nation for review and extending an invite to the public COH in 2024.

3.3.4 Chippewas of Georgina Island First Nation

- Chippewas of Georgina Island First Nation has not responded to the NOC, follow ups, and invitation to the public COH. Hydro One has and will continue to provide Project milestone updates, opportunities to comment, raise questions or concerns, and offer archaeology monitoring opportunities.

3.3.5 Curve Lake First Nation

- Curve Lake First Nation informed Hydro One they are interested in participating in the Project. Hydro One met in-person with Curve Lake First Nation Consultation representatives to discuss all Hydro One projects within their traditional territory including this Project. The concerns raised during the meeting were not in relation to the Project. Hydro One provided archeology monitoring

opportunities and the Stage 1 archaeology assessment to the First Nation for review. Hydro One has and will continue to provide Project milestone updates and offer participation opportunities in archaeology studies.

3.3.6 Hiawatha First Nation

- Hiawatha First Nation responded to the NOC and expressed their interest in participating in the Project. Through archaeology consultants, Hydro One provided opportunities for the First Nation's participation in field monitoring, however the First Nation cited not having enough resources to provide a monitor at the time of the scheduled studies. Hydro One invited the community to the public open house and offered to host it within the community. Hydro One has and will continue to provide Project updates and milestones, including opportunities to comment, raise questions and concerns, and to monitor the Stage 2 archaeology assessment.

3.3.7 Nation huronne-wendat

- Hydro One engaged with the Nation huronne-wendat for archaeology interests. Hydro One provided the Stage 1 archeology assessment to review and provided capacity funding for their participation. Hydro One will continue to provide opportunities for monitoring and reviewing the Stage 2 archaeology assessment for the Project.

3.3.8 Kawartha Nishnawbe First Nation

- Kawartha Nishnawbe First Nation responded to the NOC and met with Hydro One to discuss the Project. During the discussion, they informed that their main interest is archaeology. Kawartha Nishnawbe First Nation was offered opportunities to participate in archaeology assessments and Hydro One provided the Stage 1 archaeological assessment to the First Nation for review. Kawartha Nishnawbe First Nation was also invited to the public COH in 2024.

3.3.9 Georgian Bay Historical Métis

- Hydro One sent the NOC to Georgian Bay Metis Council. The Council has not responded to the NOC, follow ups, and invitation to the public COH. Hydro One has and will continue to provide Project milestone updates, opportunities to comment, raise questions or concerns, and offer archaeology monitoring opportunities.

3.3.10 Mississaugas of Scugog Island First Nation

- Mississaugas of Scugog Island First Nation responded to the NOC acknowledging receipt. Hydro One provided archeology monitoring opportunities and the Stage 1 archaeology assessment to the First Nation for review, where they expressed interest in continuing their involvement in the Stage 2 archaeological assessment. Hydro One will continue to provide Project milestone updates and offer participation opportunities in further archaeology assessments.

3.4 Provincial Elected Officials

As part of the consultation program for the Project, the following elected officials were contacted during the Class EA for MTF process:

- Member of Parliament (MP) for Barrie-Innisfil, John Brassard
- Member of Provincial Parliament (MPP) for Barrie-Innisfil, Andrea Khanjin

Correspondence with elected officials is included in the Record of Consultation (Appendix B.4).

3.5 Provincial Government Agencies

As part of the consultation program for the Project, the following provincial government representatives and agencies were contacted during the Class EA for MTF process:

- Provincial Agencies, including:
  - MCM, Heritage Planning Unit
  - Ministry of Energy
    - Governance, Strategy and Analytics Branch
    - Indigenous Energy Policy Unit
- MECP, Central Region
- Ministry of Mines, Mines and Minerals Division
- Ministry of Municipal Affairs and Housing (MMAH) Central Municipal Services Office, Community and Planning Development (East) Branch
- MNR, Land Use Planning Unit
- MTO, Engineering Program Delivery (Central) Department
- Infrastructure Ontario (IO)
  - Environmental Management
- Portfolio Planning, Development and Transactions
  - Ontario Energy Board
- LSRCA

No concerns were raised by the provincial agencies, however comments were provided by LSRCA (see Section 3.5.1). Correspondence with Provincial Government and Agencies is included in the Record of Consultation (Appendix B.4).

3.5.1 Lake Simcoe Region Conservation Authority (LSRCA)

In response to the NOC issued on July 2, 2023, LSRCA acknowledged receipt and informed that the proposed Project Study Area is partially regulated by LSRCA under O. Reg 179/06 (now O.Reg. 41/24 *Prohibited Activities, Exemptions and Permits*) made pursuant to the *Conservation Authorities Act*. Therefore, any development within regulated areas will require a permit from LSRCA under the CA Act.

As follow up to LSRCA's initial comments, Hydro One had a phone meeting with LSRCA on October 19, 2023 to provide an overview of the Project and discuss any potential permits and/or approvals required from the LSRCA. Hydro Oneproposed the use of the recommended approvals pathways outlined in Hydro One's 2021 Memorandum of Understanding with Conservation Ontario to which LSRCA agreed. No other comments or concerns were raised by LSRCA.

3.6 Municipal Governments and Elected Officials

As part of the consultation program for the Project, the following municipal government representatives and agencies were contacted during the Class EA for MTF process:

- City of Barrie
- Mayor Alex Nuttall
    - Councillor Gary Harvey, Ward 7
    - Councillor Nigussie Nigussie, Ward 6
    - Councillor Jim Harris, Ward 8
    - Councillor Robert Thomson, Ward 5
- Town of Innisfil
    - Mayor Lynn Dollin

Correspondences with municipal government are included in the Record of Consultation (Appendix B.4).

3.6.1 City of Barrie

On July 05, 2023, Hydro One met with the City of Barrie to discuss the Project. The City of Barrie informed that, together with Smart Centres, they are currently developing a new subdivision at 15 Harvie Road. As the subdivision is located beside the TL at Thrushwood Drive, the proposed road alignment with Brookwood Drive is potentially affected by one of the towers which might impact the flow of connecting

traffic. On August 17, 2023, Hydro One met with the City of Barrie and Smart Centres to understand the City's development plans and discuss the route alignment. Hydro One committed to reviewing tower placement in this area to understand any potential road alignment conflicts.

With regards to the Cultural Heritage Screening Report (Appendix C.2), the City of Barrie confirmed via email on September 20, 2023, that there were no municipal provincial heritage properties or interests in or adjacent to the PSA that they were aware of, based on the desktop exercise by their GIS team on the lands within the municipality boundaries. The City of Barrie highlighted that this confirmation does not eliminate the possibility of Indigenous cultural heritage resources being present in or adjacent to the Cultural Heritage Assessment Area.

3.7 Potentially Affected Interest Groups, Businesses, School Boards and Utilities

Consultation opportunities were provided to potentially affected and interested groups, businesses, school boards and utilities throughout the Class EA for MTF process. The stakeholders contacted during the Class EA for MTF process include:

- Metrolinx, Third Party Project Review
- ONxpress Transportation Partners, Utilities/Urban Transportation Systems
- Canadian National (CN) Railway
- Canadian Pacific and Kansas City South (CPKC) Railway
- IESO
- Simcoe County District School Board
- Rogers Communications Canada Inc.
- Bell Canada
- Enbridge, Corporate Head Office
- Alectra Utilities Corporation
- Organisations such as Heritage Baptist Church (HBC)
- Property owners, residents, and general members of the public within 1,000 m of the PSA

A complete list of the interest groups is provided in the Project Stakeholder List (Appendix B.1). Correspondences with potentially affected and interested groups, businesses, school boards and utilities are included in the Record of Consultation (Appendix B.4).

3.7.1 Heritage Baptist Church

In response to the NOC disseminated on July 19, 2023, Heritage Baptist Church (HBC) expressed interest in a meeting to discuss the proposed Project. On July 26 and August 24, 2023, Hydro One met with HBC to share information on the proposed Project. Discussion topics included HBC's queries on possible exposure to electric and magnetic fields, construction impacts on pick-off/drop-off at the associated school facility and had expressed interest in building a bus shelter on their property under the existing transmission lines.

3.8 Property Owners/Residents/General Members of the Public

In response to the NOC disseminated on July 19, 2023, a member of public queried on possible exposure to electric and magnetic fields (EMF) and scheduling of future open houses. In March 2024 Hydro One shared the results of third-party study on EMF exposure from a new 230 kV transmission line and plans for a second COH in the fall of 2024.

3.9 Summary of Key Comments and Concerns

Table 3.3 provides a summary of the comments and concerns raised from the interested parties throughout the Class EA for MTF consultation process.

Table 3.3 Summary of Key Comments and Concerns

Theme	Comment/Concern	Response from InnPower/Hydro One
Design of Transmission Towers	Concerns about the size and location of the transmission towers	This information was not available at the time as the Project was still in early planning stages. The size and location of the towers has now been shared with the public at the second COH and on Hydro One's website.
Alterations to the current landscape	Concerns about what the current landscape is and how it will be altered during construction and operations, including the proposed tower locations	Hydro One provided information on their approach to corridor vegetation management, as well the siting of poles. It was noted that some pole locations have been adjusted from the previous locations.
Proposed Project schedule and timeframe for construction	Inquiries about the timeframe for the Project construction and the overall schedule for the Project	Attendee was directed to the poster board on the Project timing. (See Appendix B.2 for poster boards).
Project cost	Inquiries about the Project cost	Hydro One provided high level guidance on publicly available figures.
Potential Impacts during Operational phase	Concerns about the potential impacts of EMF on the public	Hydro One met with Discovery Daycare which raised concerns during COH 1 about the potential impacts of EMF during the operational phase to provide an overview of EMF as it relates to 230kV corridors and discussed the EMF change that would occur on this line. Hydro One also shared that they are currently undertaking an EMF study and would share the results when they were available. Consultation with Discovery Daycare is ongoing, and outcomes will be captured in the Record of Consultation. Hydro One provided information on EMF exposure limits and field assessments done as part of the project. EMF levels are expected to remain well below ICNIRP industrial exposure limits.
Potential radio interference	Concerns about whether the Project will impact radio frequency	Hydro One noted that radio reception is not anticipated to be impacted at road level.
Utility Conflict - Alectra	Concerns about the proposed transmission lines and their potential impacts on Alectra transmission lines, specifically during road widening	Hydro One agreed to discuss these concerns further outside of this COH.

3.10 Final Notification and Draft Environmental Study Report Review Period

InnPower and Hydro One are providing a minimum 30-day review period, from April 4, 2025 to May 5, 2025, to allow for review and comment on this draft ESR. Written comments or questions regarding the draft ESR are to be submitted to Hydro One no later than 5 p.m. May 5, 2025, and must be addressed to:

> Adam Haulena, Environmental Planner, Hydro One Networks Inc.
> 483 Bay Street, North Tower, 14th Floor, Toronto, ON, M5G 2P5
> Phone: 1-877-345-6799 (community relations hotline)
> Email: Community.Relations@HydroOne.com

Comments and concerns received by InnPower and Hydro One during the draft ESR review period will be recognized, considered, addressed and documented. The ESR will be finalized for the proposed Project in accordance with the Class EA. Upon completion of the Class EA for MTF process, the final ESR will be filed with the MECP, and will be made available on the Project website (https://www.hydroone.com/about/corporate-information/major-projects/innpower]. The Project will then be considered acceptable to proceed as outlined in the ESR.

3.11 Statement of Completion

[**NTD: To be completed following issuance of Statement of Completion**].

4 Environmental Inventory

The following sections, and Figure 4.1 Study Area Feature Inventory, summarize the environmental baseline conditions in the PSA. Information presented below was obtained through published documents, government agency and online resources databases and mapping tools, municipal websites, government planning and guidance documents, relevant Project documents, reports commissioned by InnPower and Hydro One, and primary data collection through targeted natural heritage field surveys.

As described in the Class EA for MTF process, information from within the PSA was collected for the following:

- Agricultural resources
- Forestry resources
- Cultural heritage resources (i.e., built heritage resources, cultural heritage landscapes and archeological resources)
- Land use and communities
- Mineral resources
- Natural environment resources (e.g., air, land, water, wildlife)
- Recreational resources
- Visual and aesthetic resources (i.e., appearance of the landscape)

4.1 Agricultural Resources

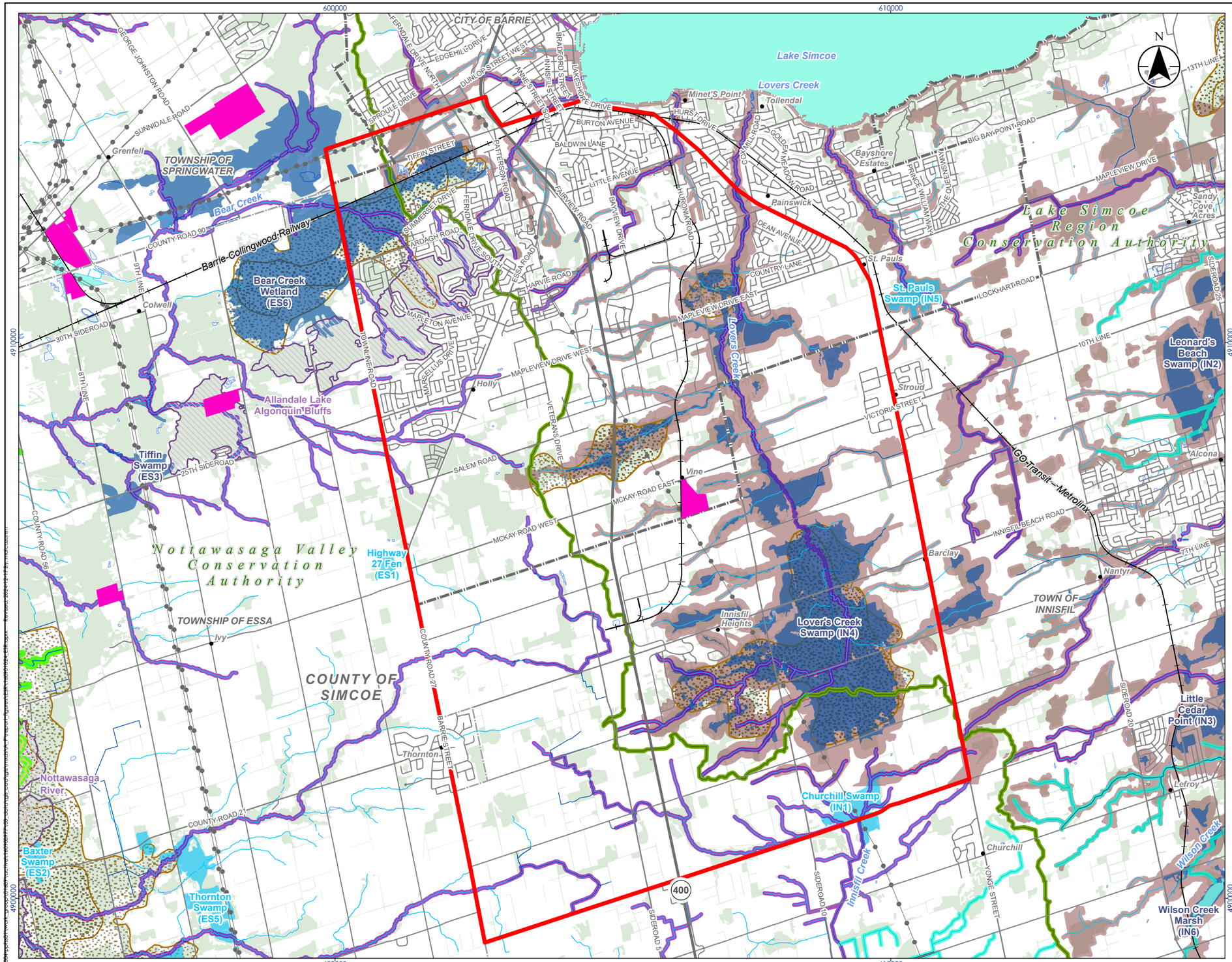
Based on the Canada Land Inventory (CLI) system, land capability for agriculture is classified into seven classes which indicate the degree of limitation imposed by the soil in its use for mechanized agriculture. The following consists of a description for each soil capability class:

- Class 1 – Soils in this class have no significant limitations in use for crops.
- Class 2 – Soils in this class have moderate limitations that restrict the range of crops or require moderate conservation practices.
- Class 3 – Soils in this class have moderately severe limitations that restrict the range of crops or require special conservation practices.
- Class 4 – Soils in this class have severe limitations that restrict the range of crops or require special conservation practices.

- Class 5 – Soils in this class have very severe limitations that restrict their capability in producing perennial forage crops, and improvement practices are feasible.
- Class 6 – Soils in this class are capable only of producing perennial forage crops, and improvement practices are not feasible.
- Class 7 – Soils in this class have no capacity for arable culture or permanent pasture.

According to the land capability data mapped by Agriculture and Agri-Food Canada (AAFC) (2013), the PSA is dominated by urban lands (unrated lands) and Class 1 land (no significant limitations). Lands of Class 2 to 5, and 7 are also identified within the PSA and are shown on Figure 4.2.

The proposed Saunders Road Site InnPower TS alternative is located within an unrated industrial park at the south end of the City of Barrie. Soils within the LSA of the proposed McKay Road East Site InnPower TS alternative have been classified as Class 5 (very severe limitations) and Class 7 (no capacity). The LSA of the proposed Side Road 10 InnPower TS alternative is dominated by Class 1 (no significant limitations) and some Class 2 soils (moderate limitations).



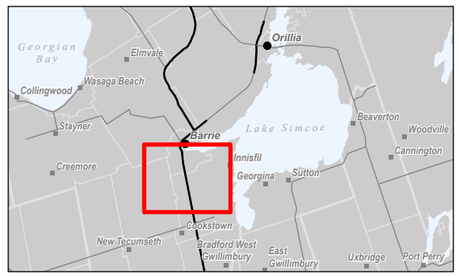
Stantec

Legend

- Project Study Area
- Constructed Drain
- Highway
- Major Road
- Minor Road
- Railway
- Hydro Line
- Watercourse (Intermittent)
- Watercourse (Permanent)
- Waterbody
- Wooded Area
- Thermal Regime, Cold
- Thermal Regime, Cool
- Active Aggregate Pit
- ANSI, Life Science
- Aquatic Species at Risk Distribution
- Conservation Authority Administrative Boundary
- Deer Wintering Area
- Regulation Limit (LSRCA & NVCA)
- Thermal Regime, Cold
- Thermal Regime, Cool
- Thermal Regime, Warm
- Wetland, Provincially Significant
- Wetland, Other Evaluated

Notes

1. Coordinate System: NAD 1983 UTM Zone 17N
2. Base features produced under license with the Ontario Ministry of Natural Resources and Forestry © King's Printer for Ontario, 2023..



Project Location
City of Barrie/
Town of Innisfil

1609600977 REVA
Prepared by MDA on 2024-12-17

Client/Project
INNPOWER CORPORATION
INNPOWER HYDRO ONE ESR

Figure No.
4.1

Title
Study Area Feature Inventory

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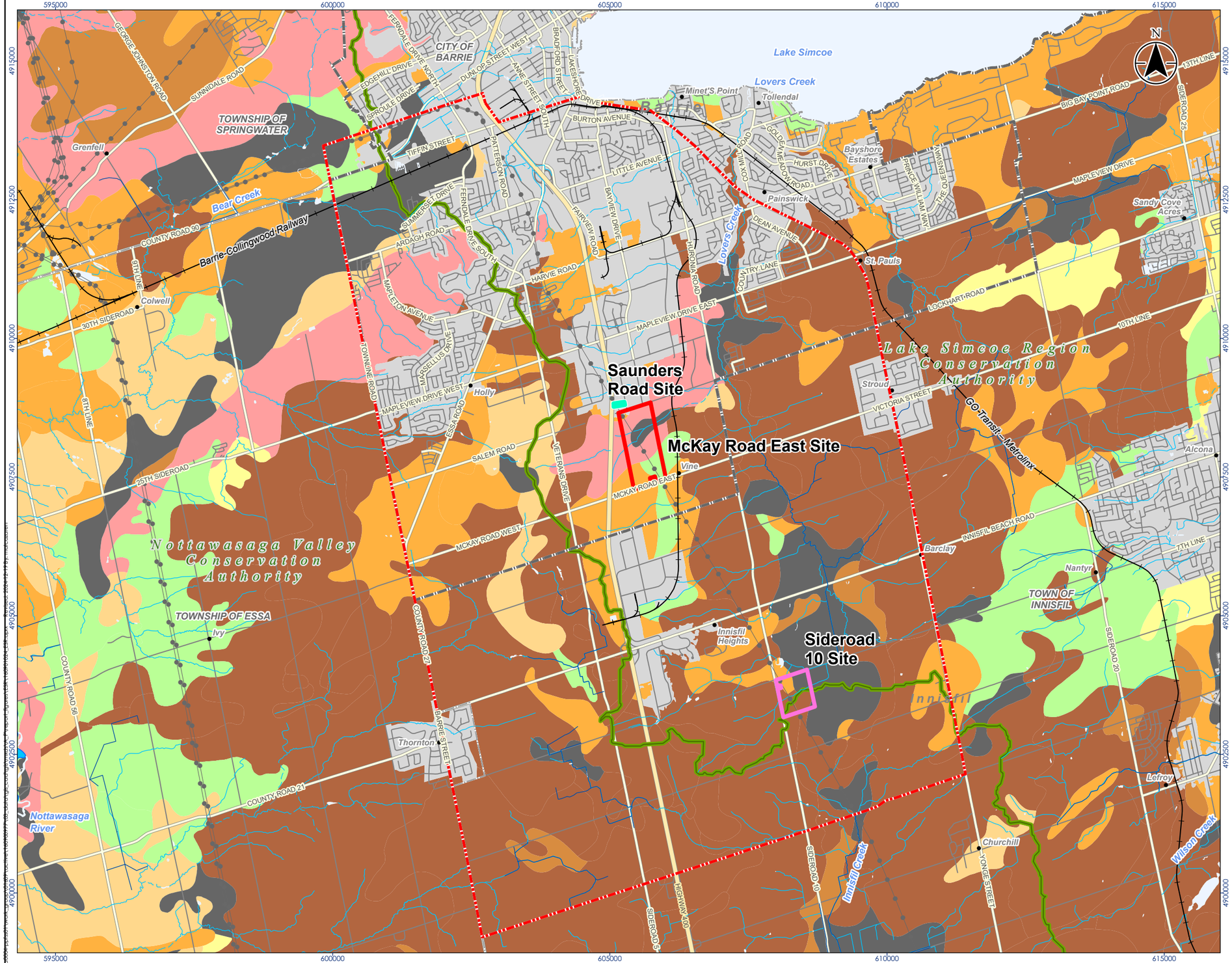

Stantec

Legend

- Project Study Area
- Saunders Road Site
- McKay Road East Site
- Sideroad 10 Site
- Railway
- Hydro Line
- Constructed Drain
- Watercourse (Intermittent)
- Watercourse (Permanent)
- Highway
- Major Road
- Minor Road
- Conservation Authority Administrative Boundary
- Municipal Boundary, Upper
- Municipal Boundary, Lower
- Waterbody

Land Capability for Agriculture

- Class 1
- Class 2
- Class 3
- Class 4
- Class 5
- Class 6
- Class 7
- Organic Soils
- Urban Areas (Unrated Lands)

0 1 2 km

1:70,000 (At original document size of 11x17)

Notes

1. Coordinate System: NAD 1983 UTM Zone 17N
2. Base features produced under license with the Ontario Ministry of Natural Resources and Forestry © King's Printer for Ontario, 2023.
3. Soil Land Capability for Agriculture data from the Soil Survey Complex Data using the Canada Land Inventory Ranking https://geohub.lio.gov.on.ca/maps/ontarioca11::soil-survey-complex.

Project Location
City of Barrie/
Town of Innisfill

1609600977 REVA
Prepared by MDA on 2024-12-19

Client/Project
INNPOWER CORPORATION
INNPOWER HYDRO ONE ESR

Figure No.
4.2

Title
Agricultural Soil Classes

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4.2 Forestry Resources

Close to 90% of Ontario forests are publicly owned and known as Crown lands. Of these Crown lands, 44% include managed forests. Forest management activities within this area are required by law to be managed sustainably. Timber harvesting in Ontario occurs on both Crown and private land. Forest harvesting on Crown land occurs according to the *Crown Forest Sustainability Act*. Private land harvest occurs at the decision of landowners.

While there are several woodlots located within the Terrestrial and Aquatic Ecosystems Study Area and adjacent lands, these areas fall outside of Forestry Management Units, Agreement Forest Areas, Forest Cover Units, Forest Resource Inventory Areas, or Wood Use Areas Forest Resources as identified through the MNR Forest Resource Inventory (MNR 2020). As such, there is no potential for the proposed Project to affect the productivity or utilization of the land for timber harvesting.

4.3 Cultural Heritage Resources

Provincial heritage properties include three types of cultural heritage resources: built heritage resources, cultural heritage landscapes, and archaeological sites. A licensed archaeologist was retained to conduct the archaeological assessments and the cultural heritage assessments were completed by a Qualified Heritage professional.

4.3.1 Archaeological Resources

The Stage 1 archaeological assessment involved background research and property inspections conducted on October 31 and November 1, 2023 to evaluate the archaeological potential of the Archaeological Assessment Area (Appendix C.4). The Archaeological Assessment Area for the Project consists of the transmission line corridor and a 120 m buffer surrounding the TL corridor comprising of approximately 142 hectares, starting at the existing Barrie TS on the north side of Tiffin Street and moving south just to the west of Highway 400 and terminating at Lockhart Road to the east of Highway 400.

In compliance with the provincial standards and guidelines set out in 2011 *Standards and Guidelines for Consultant Archaeologists* (Government of Ontario 2011), regulated by the MCM, the objectives of the Stage 1 archaeological assessment are to:

- Provide information about the study area’s geography, history, previous archaeological fieldwork, and current land conditions.
- Evaluate the study area’s archaeological potential which will support recommendations for Stage 2 survey for all or parts of the property.
- Recommend appropriate strategies for Stage 2 survey.

Archaeological potential is established by determining the likelihood of archaeological resources on a subject property. There are three waterways that cross within the Archaeological Assessment Area: Hotchkiss Creek, Whiskey Creek, and the tributaries of Lovers Creek. The three major soil types found within the Archaeological Assessment Area, Tioga sandy loam, Tioga and Vasey sandy loam complex, and Dundonald sandy loam are characterized by good drainage and would have been suitable for Indigenous and early Euro-Canadian farming practices.

An examination of the Ontario Archaeological Sites Database identified 39 registered archaeological sites within one km of the Archaeological Assessment Area, with three sites within 300 m of the Archaeological Assessment Area.

Archaeological potential can be extended to areas of early Euro-Canadian settlement, including places of military or pioneer settlements; early transportation routes; and properties listed on the municipal register or designated under the *Ontario Heritage Act* (Government of Ontario 1990) or property that local histories or informants have identified with possible historical events. Historical mapping indicates that 19th century homesteads or farmsteads, churches, historical transportation routes (e.g., Tiffin Street, Essa Road, Ardagh Road, and Harvie Road etc.), and a historical rail line are all in the Archaeological Assessment Area or within close proximity to the Archaeological Assessment Area.

The Stage 1 archaeological assessment determined parts of the Archaeological Assessment Area to have archaeological potential. Other portions of the Archaeological Assessment Area retain no or low archaeological potential due to previous disturbance, and/or permanently low and wet conditions.

4.3.2 Built Heritage Resources and Cultural Heritage Landscapes

Proposed InnPower TS Site Alternatives

The Parks Canada, the City of Barrie, the Town of Innisfil, and Canada's Historic Places websites identified no historic sites in or adjacent to the three proposed InnPower TS site alternatives and the site locations have no special association with a community, person, or historical event.

The Saunders Road Site InnPower TS alternative is located in an industrial area in the southern portion of the City of Barrie. The Cultural Heritage Assessment Area for this site include modern roadways with modern infill properties, and no trails are identified in or adjacent to the site. There are no identified United Nations Educational, Scientific and Cultural Organization World Heritage Sites in the City of Barrie. Two mid- to late-19th century residences, 36 and 110 McKay Road, located approximately 500 m from the Saunders Road Site were identified as potential landmarks in the local community or may be important in defining the character of the area.

Similarly, the Cultural Heritage Assessment Area for the McKay Road East Site include modern roadways with modern infill properties, and no trails are identified in or adjacent to the site. The two earlier-identified properties (36 and 110 McKay Road) are also situated in this site's Cultural Heritage Assessment Area. These two properties are situated in relation to the historic community of Vine, which is about 200 m east of the site along McKay Road. The age of these properties indicate that the site has potential cultural heritage value.

The Sideroad 10 Site is adjacent to one late 19th century to early 20th century red brick residence (7140 Sideroad 10), whereby the age of the property suggests potential cultural heritage value.

Proposed TL Route Alternatives

A Cultural Heritage Report (Appendix C.2) was conducted for the Route A TL alternative. While the screening checklist identified a structure over 40 years old, namely, a 19th century residence located at 12 Beacon Road. However, as the residence has been heavily modified over time, this structure was assessed with limited potential for cultural heritage value or interest. Similarly, while a railway track historically associated with the former Northern Railway line was identified in the assessment area of Route A, TL installation across the railway line is not anticipated to require encroachment into the railway ROW. Therefore, no surface impacts are anticipated within the rail corridor and the potential cultural heritage landscape is not at risk of adverse negative direct or indirect impacts.

Based on results of background research, review of historical and topographic maps, and agency consultation, the Cultural Heritage Checklist completed for the Cultural Heritage Assessment Area (i.e., 50 m buffer from the respective proposed Project Footprints) determined the following:

- For the Saunders Road Site InnPower TS alternative, no heritage potential was identified.
- For the Route A TL alternative, no structures with potential for cultural heritage value or interest were identified, except for the railway track.

Refer to Appendix C.2 for the Cultural Heritage Report.

4.4 Human Settlements

4.4.1 Land Use Planning

4.4.1.1 Provincial Planning Statement (2024)

The Provincial Policy Statement (PPS) is issued under Section 3 of the *Planning Act*. The PPS defines infrastructure as “physical structures (facilities and corridors) that form the foundation for development. Infrastructure includes: sewage and water systems, septage treatment systems, stormwater management systems, waste management systems, electricity generation facilities, electricity transmission and distribution systems, communications/telecommunications including broadband, transit and transportation corridors and facilities, active transportation systems, oil and gas pipelines and associated facilities.” (Government of Ontario 2024). As the Project will supplement power to the provincial electricity grid (as required), it would form part of the electricity transmission and distribution system and would be considered infrastructure.

Chapter 3 of the PPS sets policies for infrastructure, with Sections 3.1 and 3.8 providing direction on infrastructure corridors and facilities, including electricity generation facilities and transmission systems.

3.1.1 *"Infrastructure and public service facilities shall be provided in an efficient manner while accommodating projected needs. Planning for infrastructure and public service facilities shall be coordinated and integrated with land use planning and growth management so that they: a) are financially viable over their life cycle, which may be demonstrated through asset management planning; b) leverage the capacity of development proponents, where appropriate; and c) are available to meet current and projected needs.*

3.1.2 *Before consideration is given to developing new infrastructure and public service facilities: a) the use of existing infrastructure and public service facilities should be optimized; and b) opportunities for adaptive re-use should be considered, wherever feasible.*

3.1.*3* *Infrastructure and public service facilities should be strategically located to support the effective and efficient delivery of emergency management services, and to ensure the protection of public health and safety in accordance with the policies in Chapter 5: Protecting Public Health and Safety.*

3.8.1 *Planning authorities should provide opportunities for the development of energy supply including electricity generation facilities and transmission and distribution systems, energy storage systems, district energy, renewable energy systems, and alternative energy systems, to accommodate current and projected needs.*

All the 3 proposed sites for the TS portion of the Project are compatible with the existing transmission corridor and is supportive of the long-term use of the corridor. Furthermore, the proposed Project would form part of the electricity transmission and distribution system. The improvements are consistent with the PPS goals for energy infrastructure.

The Section 2 of the PPS requires that proponents consider significant resources which include natural heritage features, significant wildlife habitat, species at risk, water resources, cultural resources, archaeological resources, prime agricultural lands, and potential sources of minerals, aggregates and petroleum. These are considered under this report as part of the Class EA for MTF process.

The PPS definition of development also excludes any "activities that create or maintain infrastructure authorized under an environmental assessment process". Therefore, PPS policies that speak directly to regulating 'development' would not apply to this Project, as it follows an environmental assessment process.

4.4.1.2 City of Barrie Official Plan (2024)

Both the Saunders Road Site and McKay Road East Site InnPower TS alternatives are located within the City of Barrie and are designated as Employment Areas for industrial use within the City of Barrie Official Plan 2051(OP) (Section 2.6.10) (City of Barrie 2024). This land use is intended to support economic activity by recognizing and providing long-term protection to industrial-type uses which are sensitive to encroachment.

As per subsection I of the OP, this land use category does allow for storage activities but shall not be used in its entirety for the sole purpose of outside storage. Outside storage, where permitted, is subject to the appropriate screening and landscaping in accordance with the OP and City-Wide Urban Design Guidelines.

A portion of the McKay Road East Site InnPower TS alternative has been designated as Natural Heritage System and receives protection under the Lake Simcoe Protection Plan and other provincial plans. In these environmental protection areas, development and site alteration shall not be permitted unless it has been demonstrated that there is no negative impact on the environment and their ecological functions (City of Barrie 2023).

4.4.1.3 City of Barrie Consolidated Zoning By-law (2009)

The City of Barrie is creating a new Zoning By-law, which is designed to implement the vision and policies of Barrie's 2024 OP. The City of Barrie intends to produce a final draft of the updated by-law for consideration in early 2025.

According to Section 4.2.1 of the City of Barrie Consolidated Zoning By-law (By-Law 2009-141), a public utility may use any lands as long as they are developed within the provisions of that zone (City of Barrie 2009). This approach to the siting of public utilities is consistent across the policy framework in Ontario.

The Zoning By-law identifies the Saunders Road Site InnPower TS alternative and part of the McKay Road East Site InnPower TS alternative as Highway Industrial, which has specific provisions providing for front lot setbacks and exterior finishes which respond to the Official Plan direction for this area as a gateway to the City. The development standards for Highway Industrial use are provided in Table 4.1.

Table 4.1 Highway Industrial Development Standards

Parameter	Development Standards
Lot Area (min)	1300 m2
Lot Frontage (min)	30 m
Front Yard (min)	15 m
Side Yard (min)	4 m
Rear Yard (min)	8 m
Lot Coverage (max)	50%
Building Height (max)	14 m

Notes: City of Barrie Zoning By-Law (City of Barrie 2009)

4.4.1.4 Town of Innisfil Official Plan (2018)

The Sideroad 10 Site InnPower TS alternative, located within the Town of Innisfil, is primarily designated as agricultural area in the OP, with portion of the Study Area designated as an area with Key Natural Heritage Features (KNHF) and Key Hydrological Features (KHF) (Town of Innisfil 2018).

According to the Town of Innisfil OP, public and quasi-public infrastructure shall be permitted in all land use designations except for KNHF and KHF designated lands, and the Greenbelt Plan area. Where intrusion of these areas by utilities and infrastructure for the transmission of electricity is required, development will be subjected to Policy 17.2.6 and shall demonstrate that the negative impacts to the environment and their ecological functions are reduced.

4.4.1.5 Town of Innisfil Zoning By-Law (2013)

According to Section 3.47.1 of the Town of Innisfil Zoning By-law (By-Law 031-17), a public utility may use any lands provided that in any residential zone, the structure is in compliance with the height, coverage, landscaped open space regulations prescribed for the zone and there is no outside storage in the yards (Town of Innisfil 2013).

The Zoning By-law identifies the Sideroad 10 Site InnPower TS alternative as a combination of agricultural and under environmental protection. Developments within natural environmental areas shall demonstrate, to the satisfaction of the Town and the applicable conservation authority, that there will be no negative impacts on the natural features or their ecological functions.

4.4.2 Transportation

Both the Saunders Road Site and McKay Road East Site InnPower TS alternatives are located adjacent to Highway 400, with the Barrie-Collingwood Railway located east of the sites. Due to the proximity of the Saunders Road Site TS alternative to Highway 400, the western end of the property falls within MTO Permit Control Area. The Sideroad 10 Site InnPower TS alternative is located approximately 2.4 km east of Highway 400, adjacent to Sideroad 10 (arterial road) and 7th Line (local road), with plans to develop portions of Sideroad 10 into a multi-use trail and secondary trail to promote active transportation in the area (Town of Innisfil 2023).

4.4.3 First Nations Land and Territory

As outlined in Section 3.3, several Indigenous communities were consulted as part of the Class EA for MTF process. While there were no First Nation reserve lands situated within the PSA, the proposed Project is situated on land covered by Treaty 18, 1818. As per the Ministry of Energy's assessment, it was determined that the Project may have the potential to affect the Indigenous communities who hold claim Aboriginal or treaty rights protected under Section 35 of *Canada's Constitutional Act 1982* in the area. As identified in the Duty to Consult letter from the Crown confirming the list of Indigenous communities to be consulted on the Project, Hydro One and InnPower was directed to consult at the "low-end of the consultation spectrum" (MOE 2023) in respect of potential impacts to the following:

- Archaeological resource-related rights for the Nation huronne-wendat
- Potential impacts to s.35 rights and archaeological resource-related rights for the Williams Treaties First Nations[8], Kawartha Nishnawbe First Nation, and the Georgian Bay Historic Métis Community

All the communities identified by the Crown were notified, invited to participate in relevant fieldwork and kept apprised of Project developments and relevant findings throughout the EA process. Of the communities identified, the closest communities include Chippewas of Georgina Island First Nation and Chippewas of Rama First Nation.

4.5 Mineral, Oil and Gas Resources

Based on a review of the MNR Land Information Ontario database, satellite imagery interpretation and observations made during field investigations, only one active aggregate pit was identified in the PSA. This site is located approximately 300 m from the McKay Road East Site InnPower TS alternative, on adjacent land south of McKay Road East. The aggregates pit is operating above water and under a Class A licence which allows the removal of more than 20,000 tonnes of aggregate annually. No other active aggregate pits or quarries were identified in the PSA.

While no active oil and gas wells were identified in the PSA, major gas pipelines operated by Trans Canada Pipelines Limited are present and extends north across the PSA just east of Townline Road.

4.6 Natural Environmental Resources

Natural environment features including air, land, water, wildlife and wildlife habitat resources and features were factors considered within the respective PSAs. This section addresses physical and biological features in the respective PSAs including baseline information for the following:

- Physical environment
- Atmospheric environment
- Surface and groundwater resources
- Designated or special natural areas
- Natural heritage features

4.6.1 Physical Environment

The Project is located within the Lake Simcoe – Rideau ecoregion (6E) of Ontario. More than 57% of the ecoregion exists as cropland (44.4%), and pasture and abandoned fields (12.8%). Forest cover includes

[8] Alderville First Nation, Beausoleil First Nation, Curve Lake First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Hiawatha First Nation, and Mississaugas of Scugog Island First Nation

deciduous (16.0%), coniferous (5.3%), and mixed forest (8.8%). Water covers 4% of the ecoregion. Ecoregion 6E is the second most densely populated ecoregion in Ontario.

The proposed Saunders Road Site InnPower TS alternative is located in an industrial park at the south end of the City of Barrie and has no natural features, watercourses, or constructed drains in the site. While the site is located within the LSRCA jurisdiction, there are no LSRCA regulated areas in the site boundary. There is an area of the LSRCA Regulation Limit approximately 120 m north of the TS site boundary. The 6 km TL overlaps with various permanent watercourses and a small unevaluated wetland regulated by LSRCA.

The McKay Road East Site InnPower TS alternative contains a large natural area in the northern half of the site, which consists of the Lover's Creek Swamp Provincially Significant Wetlands (PSW) and two unnamed tributaries. It is also identified as a Natural Heritage System in the City of Barrie OP (City of Barrie 2024). The northern end of the site is also a designated Deer Wintering Area (NDMNR 2021). This site is situated in the LSRCA regulated watershed.

The Sideroad 10 Site InnPower TS alternative contains a large natural area in the eastern portion, which is a largely wooded area and contains the Lover's Creek Swamp PSW. It is also identified as under Environmental Protection (Town of Innisfil 2018) and is anticipated to provide habitat for a diversity of wildlife. This site is situated in LSRCA and Nottawasaga Valley Conservation Authority (NVCA) regulated watersheds.

4.6.2 Atmospheric Environment

4.6.2.1 Climate

The climate is mild and moist, classified in the Humid High Moderate Temperate Ecoclimatic Region (Ecoregions Working Group 1989). The mean length of the growing season is 205 to 230 days. A meteorological station operated by the Government of Canada and the MECP with sufficient long-term data for the general region of the Project is located in Barrie (Barrie WPCC, Climate Identifier 6110557) (Government of Canada 2024). Temperature and precipitation data presented in this section are based on annual Climate Normals data available from 1981 and 2010 (Table 4.2).

Table 4.2 Summary of Published Annual Climate Normals for the 1981 to 2010 Period for Barrie WPCC Station

Parameter	Barrie WPCC (Station ID: 6110557)
Daily average (°C)	6.9
Daily maximum (°C)	12
Daily minimum (°C)	1.9
Rainfall (mm)	709.9
Snowfall (mm)	223
Precipitation (mm)	932.9