ENTEGRUS™

Distribution System Plan

Historical Period:

2021 – 2025

Forecast Period:

2026 - 2030

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1 GLOSSARY

ACA – Asset Condition Assessment

AM – Asset Management

AMI – Advanced Metering Infrastructure

AMP – Asset Management Process

CAIDI – Customer Average Interruption Duration Index

CI – Customers Interrupted

CHI – Customer Hours Interrupted

CSA – Canadian Standard Association

DR – Disaster Recovery

DSC – Distribution System Code

DSP – Distribution System Plan

EOL – End of Life

EPI – Entegrus Powerlines Inc.

ESA – Electrical Safety Authority

GIS – Geographic Information System

GS – General Service

GUP – Good Utility Practice

IESO – Independent Electricity System Operator

ICM – Incremental Capital Module

IST – Information Systems and Technology

IT – Information Technology

KPI – Key Performance Indicator

LDC – Local Distribution Company

Legacy Entegrus – refers to Entegrus Powerline Inc. prior to its 2018 merger with St. Thomas Energy Inc.

LOS – Loss of Supply

MAIFI – Momentary Average Interruption Frequency Index

MED – Major Event Day

MWO – Maintenance Work Order

NWA – Non-Wires Alternative

O/H or OH - Overhead

O&M – Operation & Maintenance

OM&A – Operation, Maintenance & Administration

OEB – Ontario Energy Board

REG – Renewable Energy Generation

RTU – Remote Terminal Units

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SCADA – Supervisory Control and Data Acquisition

STEI – the former St. Thomas Energy Inc. (which amalgamated with Entegrus Powerlines Inc. in 2018)

TUL – Typical Useful Life

TS – Transmission Station or Transformer Station

U/G or UG – Underground

ULTC – Under-Load Tap Changing

URD – Underground Residential Distribution

USF – Utilities Standards Forum

XFMR – Transformer

2 INTRODUCTION

Entegrus Powerlines Inc. ("EPI") has prepared this 2026-2030 Distribution System Plan ("DSP", or "the 2026 DSP") in accordance with the Ontario Energy Board's ("OEB") Chapter 5 Consolidated Distribution System Plan Filing Requirements dated December 9, 2024 (the "Filing Requirements"). This DSP outlines EPI's investment plan to sustain and modernize its distribution system while balancing affordability, reliability, and responsiveness to evolving customer needs and regulatory requirements. Through an evidence-based framework, the DSP reflects EPI's commitment to delivering value to its customers and aligning with the OEB's Renewed Regulatory Framework for Electricity ("RRFE") outcomes of Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.

EPI retained Charles River Associates ("CRA") to advise on and assist with the preparation of this DSP. EPI also retained METSCO Energy Solutions ("METSCO") to perform the Asset Condition Assessment ("ACA").

2.1 OBJECTIVES & SCOPE OF WORK

On March 15, 2018, the OEB approved a Mergers, Amalgamations, Acquisitions and Divestitures ("MAAD") application (EB-2017-0212) submitted by Legacy EPI and St. Thomas Energy Inc. ("STEI") which sought leave to amalgamate. The amalgamation was completed effective April 1, 2018, and the merged entity continued as EPI. Notably, the OEB also approved the deferral of rate re-basing for the merged entity until 2026 and accepted the proposal to file a consolidated DSP in 2021 (the "2021 DSP"). See Exhibit 1, Section 1.6 for additional background information on the evolution of EPI.

The 2021 DSP, reflecting 2021-2025 integrated investments across all 17 communities served by EPI, was filed with the OEB on September 15, 2021, and is included as a supporting document in this submission (see the 2021-2025 DSP, included as Attachment A).

This is EPI's third DSP filing, following the inaugural submission in Legacy EPI's Cost of Service ("COS") Application (EB-2015-0061) for the 2016-2020 period (the "2016 DSP") and the 2021 DSP, the results of which form the Historical Period of this 2026 DSP. The 2026 DSP incorporates lessons learned from previous DSP processes, along with operational insights and improvements implemented over the past five years.

The overarching objectives of the 2026 DSP are as follows:

- **Safety**: maintain a strong focus on public and employee safety through continuous improvement and adherence to industry best practices;
- **Sustainability**: ensure system reliability and availability through targeted investments while balancing affordability for customers;
- **Customer Evolution**: respond to evolving customer needs and industry trends, including technological transformation and government policy objectives;

- **Prudent Investment**: optimize the distribution system through proactive and cost-effective investment strategies that leverage data-driven decision-making and modernized infrastructure.

These objectives form the foundation of EPI's investment approach, guiding the development of a reliable and sustainable electricity distribution system that meets current and future needs. The DSP documents the tools, processes and policies that are currently in place to facilitate informed and efficient investment decisions to support EPI's desired outcomes in a cost-effective manner. The EPI commitment to efficiency can be seen in the annual OEB LDC efficiency (stretch factor) reporting, which benchmarks total costs (including expenses and capital), based on econometric modeling. In the 2024 report (released August 2025[1]), EPI continued to be ranked in the 1st (most efficient) cost efficiency performance category and placed as the 16th most efficient out of 54 distributors, highlighting its strong cost management and performance. In 2024, EPI also met or exceeded all but one scorecard target (see Section 3.3.2.3).

In seeking to develop a five-year plan to support the continued balancing of these objectives, EPI relied on a combination of objective asset data, the results of its ongoing performance measurement work, and the objectives and the priorities identified by its customers and other key regional stakeholders. Management is confident that this DSP lays out a pragmatic and impactful investment work program, firmly grounded in both asset management analytics and professional judgement on organizational priorities and the socioeconomic environment of its service territory.

This 2026 DSP reflects a continued strong and increased investment focus on System Renewal (i.e. replacing aged infrastructure, including significant voltage conversion projects) as well as System Service (i.e. system modernization and capacity expansion). Notably, EPI is making a 2025 investment in a new breaker and feeder at St. Thomas Edgeware TS to address existing capacity constraints in that community.

To date, EPI has not filed any Incremental Capital Module ("ICM") applications. EPI does not currently plan to file any ICM applications during the 2026-2030 period. However, given evolving provincial energy policies and increasing load at EPI's 36 supply points, capacity needs may arise that require the filing of an ICM application. EPI expressly reserves the right to do so if needed.

For the purposes of this DSP, years 2021 through 2025 have been treated as the Historical Period. The Forecast Period is 2026-2030, with 2025 as the Bridge Year and 2026 as the Test Year.

2.2 Outline of the Report

EPI prepared this DSP in accordance with the 2026 OEB Chapter 5 filing requirements. The report contains four sections, including this introductory Section 2. Section 3 provides a high-level overview of

[1] See Pacific Economics Group "Empirical Research in Support of Incentive Rate-Setting: 2024 Benchmarking Update" Report to the OEB, issued Aug 18, 2025.

the DSP framework, including the evidence of coordinated planning work involving other entities, and the recent results and forward-looking plans concerning EPI's performance measurement framework. Section 4 entails an overview of EPI's asset management practices, including the recap of their evolution since the 2021 DSP filing. Section 5 showcases the EPI 2026-2030 Capital Expenditure Plan and System OM&A forecasts, along with an overview of the expenditure planning process that yielded the current plan. Among other components prescribed by the OEB and/or deemed relevant by management, Section 5 also contains the justifications for material capital projects and programs (above the materiality threshold of $195,000 as described in Section 5.3) planned for the 2026-2030 timeframe.

Where relevant, the DSP is organized using the same section headings indicated in the OEB's Filing Requirements and addresses the information outlined in each section. Other relevant information is included in separately identified sections and is intended to complement the prescribed data. Note that the OEB's Chapter 5 Filing Requirements (OEB Section 5.2.3) relating to Service Quality Requirements ("SQRs") and reliability are discussed within Section 3.3.2 of this DSP. Further details on select SQRs as presented in EPI's scorecard are discussed in Exhibit 1, Section 1.8.1 and in EPI's Business Plan (Exhibit 1, Attachment 1-B).

Please see Exhibit 1, Section 1.6.1 for background information on the evolution of EPI.

3 DISTRIBUTION SYSTEM PLAN & OVERVIEW (5.2)

Section 2 describes the key inputs EPI relied on in developing this DSP and provides an account of their evolution over the Historical Period. Section 3.1 provides an overview of the DSP's foundational elements, including the investments driving the 2026-2030 capital program, key changes since the last DSP, and the objectives and goals underlying the Plan.

Building on these plan fundamentals, Section 3.2 summarizes coordinated planning activities with third parties performed during the regular course of operating activities, along with those that took place specifically in relation to the 2026-2030 DSP preparation process. Moving to the elements of the DSP's execution, Section 3.3 addresses EPI's performance measurement and continuous improvement tracking framework, including the summary of results from the last reporting period.

3.1 DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

This section provides an overview of EPI and its service territory and discusses the key elements comprising the 2026-2030 capital investment program. This section also provides a summary of the key changes applied by EPI since the 2021 DSP, asset management process modernization, and project categorization. Finally, an overview of DSP objectives and goal is provided to demonstrate the vision underlying the Plan.

3.1.1 Utility Description and General Facts

EPI is a regulated electricity distributor that owns and operates distribution systems serving 17 communities in Southwestern Ontario, as specified in its Electricity Distribution License ED-2002-0563. Figure 1 illustrates EPI's service territory, which encompasses 134 km² of non-contiguous urban areas spread over a geographic region of more than 5,000 km², bordered by Windsor/Essex (to the west) to London (to the east), Sarnia (to the north), and Lake Erie (to the south). As of December 31, 2024, EPI served 63,483 electricity distribution customers across its service area.

Figure 1: EPI Service Territory

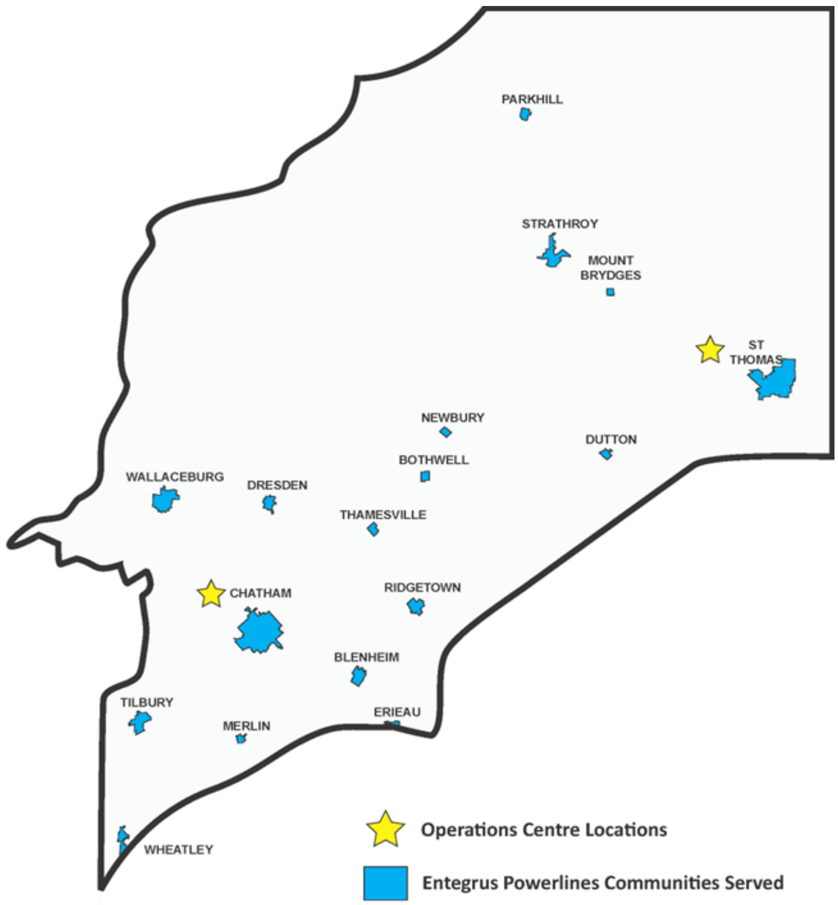


Table 3-1 below shows total customers segmented by community as at December 31, 2024. While the Residential and Small General Service rates classes have the highest number of customers, EPI serves a strong large commercial and industrial base as well. As noted below, the communities of Chatham and St. Thomas account for a significant portion of EPI load.

Table 3-2 below shows total customers segmented by rate class by year from 2015 to 2024. Over the 9-year period, EPI customer count has increased by 10%. As shown below, the EPI customer growth rate spikes between 2019 and 2022 before stabilizing near historical levels in 2023 and 2024. Notably, the City of St. Thomas experienced unprecedented Residential customer growth starting in 2019 through 2022. At the same time, other communities in the EPI Northeast Region (particularly Strathroy and Mt. Brydges) experienced growth driven by the proximity of all three of these communities to London, to which they are increasingly seen as bedroom communities. The community of Chatham in the EPI Southwest Region also experienced strong growth from 2019 through 2022.

Table 3-1: Customer Count by Community

Community	Rate Class				
	Residential	**GS < 50**	**GS > 50**	**Large Use**	**Total Count**
BLENHEIM	1,848	224	23		2,095
BOTHWELL	415	58	3		476
CHATHAM	17,864	1,694	166	2	19,726
DRESDEN	1,114	137	11		1,262
DUTTON	700	84	2		786
ERIEAU	340	48	1		389
MERLIN	294	36			330
MOUNT BRYDGES	1,374	92	4		1,470
NEWBURY	185	37	2		224
PARKHILL	710	93	6		809
RIDGETOWN	1,412	170	16		1,598
ST THOMAS	17,680	1,813	130		19,623
STRATHROY	5,706	581	62	1	6,350
THAMESVILLE	356	85	2		443
TILBURY	2,032	221	29	1	2,283
WALLACEBURG	4,358	457	45		4,860
WHEATLEY	680	73	6		759
Grand Total	**57,068**	**5,903**	**508**	**4**	**63,483**

Table 3-2: Customer Count by Rate Class

Year	Residential	GS<50	GS>50	Large Use	Total	YOY Increase	Cumulative Incr
Dec 31, 2024	57,068	5,903	508	4	63,483	0.9%	110.0%
Dec 31, 2023	56,526	5,875	507	4	62,912	0.8%	109.0%
Dec 31, 2022	56,078	5,845	515	4	62,442	1.5%	108.2%
Dec 31, 2021	55,226	5,752	527	2	61,507	1.5%	106.5%
Dec 31, 2020	54,315	5,712	558	2	60,587	1.3%	104.9%
Dec 31, 2019	53,550	5,695	563	2	59,810	1.1%	103.6%
Dec 31, 2018	52,940	5,692	552	2	59,186	0.9%	102.5%
Dec 31, 2017	52,431	5,680	548	2	58,661	1.0%	101.6%
Dec 31, 2016	51,867	5,629	581	2	58,079	0.6%	100.6%
Dec 31, 2015	51,494	5,646	590	1	57,731	-	-

The EPI service territory today is a product of multiple acquisitions and amalgamations of previously independent distributors dating back to the mid-2000s. The most recent and significant addition to EPI's asset base is the amalgamation of EPI's assets with those of the former STEI, approved by the OEB on March 15, 2018 and effective April 1, 2018. Owing to this most recent amalgamation, the total customer count of pre-merger EPI to post-merger EPI has grown by almost 50%. Integration activities were described in the 2021 DSP. Among others, Sections 3.1.3, 3.2.2, 4.1.2, and 4.8, contain additional information on the integration activities impacting the preparation of this DSP.

Given the non-contiguous nature of its service territory, EPI receives power from Hydro One Networks Inc. ("Hydro One") at both transmission and distribution voltages and is thereby an embedded distributor at certain supply points. As detailed in relevant sections of this Plan, EPI maintains a regular collaborative relationship with Hydro One on various planning and operational matters affecting the utilities' neighboring assets. This collaboration has led to significant positive service outcomes for the communities served by EPI, such as reducing Loss of Supply-related service outages, conducting local area system planning studies, and mutually conducting power quality studies.

Power quality was a key focus of the 2016 DSP to the extent that EPI included a power quality metric in its scorecard. Since then, substantial focus has been placed on working with customers on such issues, resulting in a near elimination of incoming power quality complaints (see Section 3.3.1.1.3). Accordingly, while EPI will continue to offer this service to its customers, the power quality metric has been discontinued.

The EPI distribution system is supported through an extensive (and geographically diverse) array of assets, as briefly summarized in Table 3-3 below.

Table 3-3: EPI Asset Overview

Asset Type	Total Count
Total Conductor Length (km)	997
Poles	20,663
Transformers	6,028
Overhead Switches	728
Station Switchgear	38
Feeders	63
Circuit Breakers	13

This DSP outlines EPI's investment strategy for the necessary asset renewal and additions, and system enhancement actions required to align with evolving customer needs, operational performance, and regulatory compliance.

3.1.2 Capital Investment Highlights

Leveraging the Asset Management and Planning tools and processes described herein, EPI has developed a five-year Capital Expenditure Plan summarized in the table below. Detailed breakdowns are available in Section 5.1. Capital project details are available in Attachment J.

Projects and programs are categorized based on the trigger driver for the particular investment.

- System Access investments are modifications (including asset relocation) to the distribution system that EPI is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.
- System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of EPI's distribution system to provide customers with electricity services.
- System Service investments are modifications to EPI's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.
- General Plant investments are modifications, replacements, or additions to EPI'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 operations activities.

Table 3-4: Historical and Forecast Capital Expenditures ($'000s)

CATEGORY	Historical Period ($'000s)				Bridge Year	Forecast Period ($'000s)				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System Access	$6,867	$9,910	$5,951	$5,145	$4,559	$4,890	$4,423	$4,552	$4,651	$4,752
System Renewal	$7,083	$7,080	$8,350	$10,384	$9,863	$9,656	$10,665	$10,233	$10,848	$11,320
System Service	$1,242	$901	$1,102	$1,203	$5,226	$2,245	$2,191	$2,480	$2,528	$2,419
General Plant	$1,885	$2,157	$2,398	$2,647	$3,899	$3,433	$3,034	$2,560	$2,870	$2,995
TOTAL EXPENDITURE	$17,077	$20,048	$17,801	$19,379	$23,548	$20,224	$20,313	$19,825	$20,897	$21,486
Capital Contributions	-$2,842	-$5,888	-$3,068	-$2,071	-$1,545	-$1,671	-$1,699	-$1,749	-$1,783	-$1,819
NET CAPITAL EXPENDITURES	**$14,235**	**$14,159**	**$14,733**	**$17,308**	**$22,003**	**$18,553**	**$18,614**	**$18,076**	**$19,114**	**$19,668**
System O&M	$4,628	$5,287	$5,567	$6,007	$6,404	$6,874	$7,080	$7,292	$7,511	$7,736

Note 1: The table above reflects the reclassifications of certain program types occurring in the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

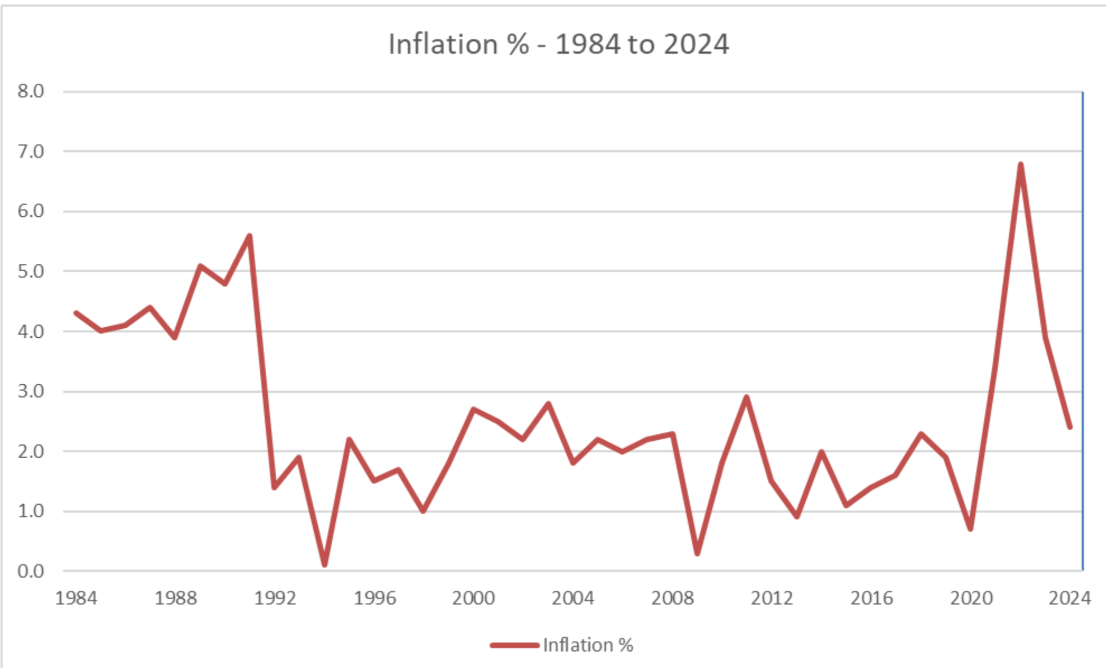
Note 2: Capital contributions are collected in accordance with the DSC and the provisions of its COS. In December 2024, Amendments to the DSC to Facilitate the Connection of Housing Developments and Residential (EB-2024-0092) were enacted. The amendments included the extension of the revenue horizon for residential housing developments from 25 to 40 years. This extension results in 15 more years being included in the economic evaluation process, which in turn, also reduces the amount of capital contributions that EPI will collect from customers. This change has been incorporated into this DSP.

As further discussed below, 2025 Bridge Year System Service contains a new breaker and feeder at the St. Thomas Edgeware TS to address existing capacity constraints.

More broadly, inflation levels, as measured by the Consumer Price Index and reflected in Figure 2 below, have been significantly higher in recent years compared to the historical average. While inflation remained relatively stable and modest through much of the past three decades, the period from 2021 to 2023 experienced a sharp and sustained increase, with 2022 reaching the highest rate in the last forty years. These elevated inflationary conditions have increased the costs of goods, materials, and contracted services, which in turn have directly affected EPI's cost structure.

Although inflation has moderated from its 2022 peak, current levels remain above most historical norms. Consequently, the higher cost base established in recent years continues to affect EPI's capital expenditures, coincident with the OEB's Price Cap IR inflation factor increasing cumulatively by 21% between 2020 and 2025.

Figure 2: Inflation 1984-2024



Beyond the significant inflation noted above, the pandemic period also brought supply chain disruptions, which impacted project costs and, in some cases, timelines. In response, EPI enhanced its collaborative procurement practices, leveraged joint purchasing agreements, and adopted flexible project management approaches to mitigate these pressures. These strategies ensured the continued delivery of key projects while maintaining affordability and reliability for customers.

3.1.2.1 System Access

System Access investments are enhancements and modifications to the distribution system that EPI is obligated to undertake in response to requests for access to electricity services from both load and generation customers, as well as system changes such as asset relocations required to support customer or third-party objectives (see Section 5.3.1 - System Access Capital Projects for more details). These projects are primarily non-discretionary and dictated by EPI's obligations as a licensed distributor. This category also covers capitalized engineering costs associated with preparing work for customer and third-party requests.

Key 2026-2030 System Access investment drivers include:

- Residential, commercial, and industrial customer connections, upgrades or modifications to existing facilities to meet evolving capacity requirements, and relocation of utility infrastructure requested by provincial, regional, municipal, or private sector entities. EPI remains focused on aligning with regional growth plans and evolving service territory needs. Further detail on third-party consultations conducted to produce this plan as well as ongoing consultations is provided in Section Coordinated Planning with Third Parties (5.2.2)3.2
- Anticipated economic development in the region, including the planned Volkswagen EV battery plant adjacent to the service territory in St. Thomas, may result in incremental load growth. Some economic spin-off growth in St. Thomas is anticipated; however, the extent and timing remain uncertain.
- Engineering and design support, which continues to be a critical component of System Access expenditures. Through the Historical Period, EPI has deliberately expanded its engineering resources in recognition of the industry's growing complexity, including technologies such as DERs and NWAs. These dedicated professionals prepare detailed design and construction packages, perform capacity studies, and coordinate closely with Hydro One, the IESO, municipalities, and developers to ensure customer needs are properly met.

3.1.2.2 System Renewal

System Renewal investment relates to the replacement and/or refurbishment of aged, deteriorating, or failed system assets; such investment is essential to maintain the ability to provide electricity service in a safe and reliable manner. Where economically feasible and driven by evolving technical standards, System Renewal activities may also include upgrades in capacity, design, remote operability, or other operational capabilities such as metering renewal, along with the replacement of various assets. This category also encompasses replacing failed assets identified (emergency response) while rectifying system outages and/or preparing and executing planned renewal work.

Key 2026-2030 Forecast Period System Renewal investments include:

- Proactive replacement of aged and degraded distribution assets, as identified in the 2024 ACA, to ensure distribution system sustainability and reliability
- A significant ongoing voltage conversion program to modernize low-voltage overhead and underground systems operating at lower voltages to modern 27.6 kV infrastructure. This program is a strategic pillar of EPI's approach to managing aging infrastructure. By converting feeders and decommissioning legacy low voltage substations, EPI avoids significant station rebuild costs while preparing for future load growth. The investments will assist in increasing operational efficiency, enhance capacity and make the system more conducive to the emerging types of grid use (i.e. EVs, distributed generation, small-scale storage).
- Phased replacement of aging smart meters and associated Advanced Metering Infrastructure "(AMI"). EPI is continuing to refresh its AMI assets amidst a paced migration to a single smart meter system, including life-cycling of smart meters and core infrastructure such as gateways and servers, etc. Further detail is provided in Section 4. As an approved early adopter of smart meters, EPI

originally commenced installing its smart meter fleet in 2006-2007. Accordingly, many of these meters are past their typical lifespan and sustainment investments are required over the 2026-2030 Forecast Period. During the 2026 – 2030 period, approximately 39,700 meter seals will expire. Where possible, EPI utilizes the Measurement Canada Sampling program to ensure measurement accuracy and minimize replacement cost. Approximately 5,000 meters tested poorly during the 2nd seal period sampling in 2024. As per Measurement Canada's sampling regulation, the lots were granted the maximum two-year extension without the ability to be sampled again and must be replaced no later than 2026, which has led to some acceleration of smart meter replacement in this 2026 DSP.

- The adoption of a new design standard for the replacement of residential transformers (as well as for new developments) to a 6 kVA per customer standard with an option for 12 kVA, driven by homebuilding trends and system demands associated with DERs.

3.1.2.3 System Service

System Service investment involves modifications to EPI's distribution system, supporting equipment, and/or upstream transmission and distribution assets that are essential to ensure long-term service continuity and the ability to meet both regular and emerging customer service requirements and operational objectives. This includes capital costs incurred in monitoring system operations and investments in new technology that provide asset performance visibility and facilitate system efficiency, reliability, and other benefits.

Key 2026-2030 Forecast Period System Service investments include:

- Distribution automation through deployment of intelligent sectionalizing switches and reclosers for automated outage restoration and increased segmentation. These smart switches enable faster isolation of faults, reducing the duration and extent of outages, while reclosers improve fault detection and enable automatic restoration.A System Modernization program to begin phasing out the existing low voltage system in Mt. Brydges enabling expanded capacity to meet anticipated demand in these growing communities and improve resiliency. Further detail is provided in Section 5.1.2.3.3.
- Incremental transformer investments across the service territory to enhance capacity and proactively replace undersized assets at risk of failure, ensuring continued reliability under growing load conditions. Further detail provided in Section 5.1.2.3.3.
- New feeder ties and reconductoring projects to increase operational flexibility and minimize outage impacts.
- Investments in reclosers and load break switches, which have already mitigated a combined 124,500 Customer Outage Hours since 2017 across EPI communities.
- Ongoing support of EPI's Control Room and continued enhancements to its Asset Management and field inspection capabilities.

Investment in grid modernization, including Distributed Energy Resource ("DER") infrastructure integration, aligns with customer feedback supporting modernized, reliable infrastructure.

3.1.2.4 General Plant

General Plant investments encompass the replacement, enhancement or additions to EPI's assets that, while not directly part of the distribution system, are essential to supporting day-to-day operations and ensuring the health, safety, and efficiency of EPI staff. This category includes investments in land and buildings, tools, construction and maintenance equipment, fleet (rolling stock), and information technology hardware and software.

In 2024, EPI completed a Geographic Information System ("GIS") upgrade, enhancing mobile and web accessibility, improving data integrity, and enabling faster decision-making during outages and planned work.

Key General Plant investments for the 2026-2030 Forecast period include:

- Upgrades to IT infrastructure, including cybersecurity measures and GIS advancements. EPI is also prioritizing advanced analytics tools to enhance system monitoring. Additional investments are planned for server upgrades and data redundancy protocols to support system reliability.
- Facility updates, focused on maintaining core building systems in the Chatham and St. Thomas operating centers, as further described in Section 4.8. This includes the previously deferred replacement of the Chatham Operations Centre roof, with work occurring over a two-year period starting in 2025.
- Lifecycle replacement of vehicles, tools, and equipment, ensuring safe and efficient operations.

While Entegrus is addressing some major building repairs as noted above, other facility updates, such as yard surface, continue to be deferred in this current DSP to focus investment on System Renewal and other priorities described above. Further detail is provided in Section 5.

3.1.3 Key Changes Since Last DSP

As noted above, this is EPI's third DSP filing, following the submission of the 2016 DSP and 2021 DSP (the results of which form the Historical Period of this 2026 DSP). The 2021 DSP continued and expanded on key focus areas of the 2016 DSP, specifically the replacement of aging infrastructure and modernization of the distribution system to maintain (or improve) reliability while keeping distribution rates affordable for customers. This 2026 DSP reflects a continued strong and increased investment focus on System Renewal (i.e. replacing aged infrastructure, including significant voltage conversion projects) as well as System Service (i.e. system modernization and capacity expansion).

Data Collection Improvements and Asset Condition Assessment

Since 2021, the sophistication and volume of asset condition information collected by EPI has increased, improving asset management practices as the data became available (see Sections 4.2.2 and 4.3.4 for discussion on ACA evolution). This information, some of which is summarized below, has been used by EPI to continuously monitor its asset management and capital expenditure planning process – and has resulted in both the improvements shown throughout and the increased spending recommended in this 2026-2030 DSP.

While EPI continues to perform visual inspections of its poles using its historical report-by-exception methodology, management also instituted a resistograph "pole-drill"-based inspection program in 2018 targeting 1,000 poles/year. This program inspects a sample group of poles annually to ensure that the most degraded assets are prioritized for immediate attention. In 2022, EPI further refined the "pole drill" test standards, providing richer information for better analysis and increasing the testing rate to approximately 2,000 poles per year. In 2025, Entegrus further expanded its pole inspection program. Progress toward a complete set of drill tests can be seen in Attachment B, Section 4.2.1.

Additional asset condition assessment work was predominantly performed in 2024 in support of this DSP filing. This work was conducted with the assistance of third-party engineering and analytics firm METSCO and was based on asset management principles and processes to ensure prudent management and prioritization of asset replacement. These processes are outlined in the ACA report prepared by METSCO included as Attachment B. To complement improvements in data availability on EPI assets, METSCO introduced refinements to its ACA methodology for the 2024 filing. These refinements include adding and removing parameters for consideration when performing the asset health evaluation. As an example, based on recommendations in the 2021 ACA, EPI made significant improvements to its asset inspection process. Several key asset classes (including wood poles) are now evaluated using multiple parameters instead of a single parameter (age). While this represents an improvement in methodology, it also means that the current ACA is not directly comparable to historical EPI ACAs (2016 and 2021), as the category definitions have evolved. See Attachment B, Section 3.6 details for more information.

In the 2024 ACA, METSCO delineated 15 categories and subcategories of assets, covering the entire EPI-installed asset base. The ACA showed that key asset classes were in "Very Poor" condition. Assets identified as "Very Poor" in the ACA have reached the end of their useful life and are at an elevated risk of failure. This includes the following asset category percentages identified as "Very Poor": Station Switches (100%), Wood Poles (9%), Steel Poles (10%), Concrete Poles (65%), Underground Primary Cables (22%), and Overhead Switches (10%). This shows a continued need for reinvestment to maintain system integrity, and in the case of Station Switches, reflect the need to document additional asset condition data. In its report conclusion, METSCO identified a "significant need for investment into EPI's systems" and assessed that such investments will "provide substantial benefits that will empower EPI to better serve its current customers and accommodate growth" (see Attachment B, Section 6).

Engineering Resources

As noted in the 2021 DSP, starting in 2017, the overall duration and frequency of outages across the 16 Legacy EPI (EPI-Main) communities significantly deteriorated, indicating that sustained outages were occurring more frequently and lasting longer on average. This signaled the need for more intensive engineering analysis and modernized system solutions. To address these challenges and support the evolving technical and regulatory requirements, EPI expanded its engineering resources by adding Engineers-in-Training ("EITs")[2] and an Engineering Technologist.

Incremental EITs were added in 2016 and 2018. While these positions contribute to succession planning, their technical work supports safe and reliable distribution system operation and modernization. EITs contribute to modelling, system studies, and planning activities, including DER integration, protection and load flow analyses, SCADA development, system design reviews, technical documentation, and evaluating new technologies to ensure safe, reliable operations and consistent engineering standards.

Incremental Engineering Technologist was hired in 2024 to address growing demands in design and project delivery. Engineering Technologists handle the design, planning, and execution of overhead and underground electrical projects, including cost estimating, material planning, layout design, and coordination with internal teams, contractors, and customers. Their work ensures compliance with standards and supports timely project execution.

For additional details on workforce planning and engineering resources, see Exhibit 4, Section 4.4.7.

These engineering resources have also assisted with smart grid deployment to manage the impact of outages through a combination of asset replacement and the implementation of distribution automation for automatic restoration in affected areas. These automation investments, entailing a mix of reclosures and automated load break switches, successfully mitigate loss of supply events as well as provide benefits to EPI's system. Ultimately, this has resulted in a combined 124,500 of avoided Customer Hours of Interruption since deployment in 2017. See Section 5.1.2.3.1 for more details.

Mapping and Visualization Improvements

Better visualization of the distribution system through enhanced digital mapping is another key ongoing focus. EPI's digital maps enable more timely updates as the system experiences growth, or conversion work occurs, thus facilitating safer operations in real time. The enhanced digital maps have also allowed for modernization of Control Room processes, improving the accuracy, ease of access and visibility of a live system view to EPI field staff. Further, the associated electronic enhancements provided additional resiliency in the event the main control room itself becomes physically unavailable due to equipment failure or natural disaster.

Post-merger, the mapping project and GIS system, as well as the modernized/digitized Chatham Control Room, were extended to the St. Thomas service territory. This included a full revision of all asset nomenclature for the St. Thomas Region, to align it with EPI's mapping standards completed in 2022. In 2021, a second full-time System Operator was added to the staff, complemented by several qualified backup Operators.

[2] The term EIT is used for familiarity and for consistency to EB-2015-0061. These roles are now typically referred to as "Engineering Associates" to address changes in the Professional Engineers of Ontario ("PEO") rules.

In 2024 EPI completed a major version upgrade on its GIS system. This upgrade included migration to a new data model, as well as a full replacement of all client and server software associated with the system. This new software makes GIS data more accessible on mobile devices and the web, while also improving data integrity and streamlining our licensing.

Addition of Data Scientist Role

In 2025, EPI hired a dedicated Data Scientist to enhance its analytics capabilities in support of asset management, system planning, and broader operational decision-making. Reporting to the Director of Asset Management & System Modernization, with a dotted-line to the Director of IT, this role focuses on developing predictive models, managing data pipelines, and supporting AI-enabled tools.

The position reflects EPI's recognition of the growing importance of advanced analytics as the system becomes more complex due to electrification, automation, and digitalization. This role initially supports asset management activities but is expected to expand across departments in the Forecast Period.

One of the near-term applications of this internal capability is the development of an AI tool to identify transformers most at risk of overload, which directly informs planned investments in proactive transformer replacement. This application is described in greater detail in Section 5.1.2.3.3, where EPI outlines how analytics-driven risk detection is guiding incremental investment to support localized load growth and asset renewal.

Further details on workforce planning and staffing are provided in Exhibit 4, Section 4.4.7.

Submersible Transformer Conversion Program

EPI has continued its program to remove and replace difficult-to-operate transformers. As of 2024, the last remaining "Pole-Trans" style transformer was removed, improving safety and reliability for impacted customers. EPI continues to convert submersible transformers, installed primarily in the 1980s and 1990s, and which are situated below ground in vaults and are susceptible to flooding. These aging transformers pose challenges for maintenance crews and are prone to long interruption times upon failure, as accessing and repairing these units is more complex than above-ground alternatives. Through voltage conversion and a dedicated submersible phase-out program, these assets are being systematically replaced with more accessible and resilient pad-mounted alternatives.

Project Prioritization and Categorization

When determining the relative ranking of projects for prioritizing the investments, EPI has made two changes to the ranking criteria. One change is the harmonization of the "Employee Safety" and "Customer Safety" categories into a single criterion. Additionally, EPI has introduced a new criterion, "System Modernization," designed to address new needs associated with intensification and the evolution of the distribution system.

EPI has updated certain project listing categorizations to reflect completed programs and other key focus alignments, as further discussed in Section 5.1.4.

3.1.4 DSP Objectives

In synthesizing its Mission, Vision, and Core Values statements and strategic goals shown in Exhibit 1, Section 1.3, EPI has the following objectives for its capital program:

Objective 1 - Safety: Ongoing pursuit of Public and Employee safety through process improvement opportunities as evident through EPI's successful company-wide adoption of the Infrastructure Health and Safety Association ("IHSA") Certification in Ontario ("COR") certification and other initiatives. The EPI Safety capital program objective encompasses the OEB's RRFE performance outcome of Operational Effectiveness and Public Policy Responsiveness and ties to EPI's Core Values of Safety and Inspired and Empowered People.

Objective 2 – Sustainability: Maintain the distribution system by making the needed investments to maintain system reliability (through asset renewal and distribution modernization) and availability (addressing increased loading and ensuring supply capacity) while controlling rates and integrating environmentally responsible practices to minimize the ecological impact of EPI's operations and asset base. The EPI Customer Evolution capital program objective encompasses the OEB's RRFE performance outcomes of Customer Focus and Public Policy Responsiveness and ties to EPI's Core Values of Customer and Community Focus and Operational Excellence.

Objective 3 – Customer Evolution: Responsiveness to emerging customer growth and industry transformation associated with NWAs, DERs, electrification, and other government policy objectives. The EPI Customer Evolution capital program objective encompasses the OEB's RRFE performance outcomes of Operational Effectiveness and Public Policy Responsiveness and ties to EPI's Core Values of Customer and Community Focus and Operational Excellence.

Objective 4 – Prudent investment: Cost-effective management of the distribution system to meet current and anticipated needs through data-driven asset management practices and adopting innovative technologies. This includes focusing on the proactive replacement of aged and deteriorated assets with modern, efficient infrastructure to optimize system performance. The EPI Prudent Investment capital program objective encompasses the OEB's RRFE performance outcomes of Operational Effectiveness and Financial Performance and ties to EPI's Core Values of Customer and Community Focus and Operational Excellence, Operational Excellence and Sustainable Growth.

The following OEB objectives and values are the primary drivers for each goal:

Table 3-5: EPI Objective and OEB Performance Outcomes

Capital Planning Goal	RRFE Performance Outcomes	EPI Core Values
Objective 1 – Safety	Operational Effectiveness – Safety Public Policy Responsiveness	Safety Inspired and Empowered People
Objective 2 – Sustainability	Operational Effectiveness – Reliability Public Policy Responsiveness	Customer and Community Focus Operational Excellence

Objective 3 – Customer Evolution	Customer Focus Public Policy Responsiveness	Customer and Community Focus Operational Excellence
Objective 4 – Prudent investment	Operational Effectiveness – Asset Management Operational Effectiveness – Cost Control Financial Performance	Customer and Community Focus Operational Excellence Sustainable Growth

To help realize these four objectives, EPI has outlined the following strategies for this DSP:

- Investment in reliability and availability: prioritize capital investments that maintain system reliability and availability while managing rate impacts.
- Support for evolving customer energy needs and intensification: modify residential engineering standards and planning practices to facilitate increased consumer access to electricity, supporting broader electrification and support urban intensification efforts aligned with provincial housing objectives.
- Integration of DERs and NWAs: enhance the distribution system's capacity to integrate DERs and NWAs, aligning with industry transformation and policy objectives.
- Environmentally responsible practices: integrate environmentally responsible practices into all operations to minimize the ecological impact of EPI's asset base, and the impact of climate change.
- Avoidance of 4kV substation rebuilds: continue targeted conversion programs to phase out 4kV substations, thereby avoiding costly rebuilds and improving system efficiency and capacity.
- Proactive replacement of high importance aged assets: focus on the proactive replacement of high importance aged and deteriorated assets with modern, efficient infrastructure to maintain system reliability and performance.
- Adoption of innovative technologies: implement modern tools and innovative technologies to support effective asset management, system visibility and cost-effective operational performance.
- Data-driven decision making: utilize data-driven modelling approaches to prioritize and optimize capital investments, ensuring prudent and effective use of resources.

In addition, EPI will also continue to uphold its mission, vision, and values by focusing on the strategic priorities previously noted and further detailed in EPI's Business Plan (see Exhibit 1, Section 1.3).

3.2 Coordinated Planning with Third Parties (5.2.2)

In preparing this DSP, EPI relied on the insights from a range of consultation activities that occur in the normal course of its operations, as well as those engagement activities dedicated specifically to the DSP development and preparation of the COS Application. This includes a variety of consultative activities with EPI's customers, subdivision developers, regional planning work across the electricity regions that make up EPI's service area, issue-specific collaboration with Hydro One, telecommunication companies, and engagements with local municipal authorities. The following sections describe each type of consultation activity in greater detail.

3.2.1 Customer Consultations

3.2.1.1 Regular Engagement and Consultation Activities

Residential Customers

EPI makes available a variety of regular and cyclical avenues for its residential customers to provide feedback on all aspects of its operations to ensure that it continues to meet their needs, captures their suggestions for improvements to the overall customer experience, and provides information about its planned and ongoing activities. In conducting this work, EPI relies on the following channels:

- **Call Centre Communication**: inquiries, complaints, and commentary including billing and account-related work (such as move in / move out) are addressed by EPI's customer service representatives who are equipped with a range of IT tools and information resources to accommodate requests or to direct inquiries elsewhere in the organization.
- **Engineering Department Communication**: all classes of EPI customers can contact the utility's Engineering Department to request a range of services or provide feedback on utility activities such as metering accuracy verifications, power quality concerns, modifications to utility pole attachments, small vegetation management projects, or resolution of other technical questions or concerns.
- **Neighbourhood Communication**: EPI staff drop off information letters to customers before working at or near customer premises. These letters explain the need for replacement, or upgrading, of hydro services, the work that is involved in the project (i.e. replacing existing poles and installation of new wires), and the primary EPI contact. EPI staff frequently engage in dialogue with customers throughout the implementation process. In addition, prior to conducting work that will result in commercial outages, EPI staff visit customer premises to survey the best times for outages.
- **Website and Social Media Feeds**: EPI customers can gain access to a variety of information online regarding the utility's operational and planning activities on the company's website as well as via social media feeds. This includes information about self-service options, billing and rate choice information, customer programs and promotions, conservation tips, planned maintenance, outage restoration updates, and an enhanced online outage map. EPI employs web traffic analytics to identify the issues of greatest interest to the customer base to inform its future planning and communications efforts.
- **Survey Tools:** EPI's residential customers can share their feedback on a range of topics by way of a variety of surveys that the utility conducts. These include surveys administered during COS application-specific customer engagement, as well as bi-weekly transactional surveys that follow the resolution of a customer-initiated request, annual "top-down" Customer Satisfaction Surveys and Public Safety Awareness Surveys.
- **Advertising:** EPI regularly utilizes bill insert messaging, website and social media ads, and formal press releases in the local media outlets to conduct awareness campaigns, notify communities of upcoming project-related disruptions, or advertise new service offerings. The feedback EPI

receives from its residential customers informs a variety of facets of its system planning, including identification of locations for reliability and plant relocation projects, capacity planning, investments in customer-facing information technology, and understanding of customer needs and preferences with respect to the balance of capital investment priorities.

Commercial and Industrial Customers

In addition to the engagement tools listed above, EPI consults with its Commercial and Industrial ("C&I") customers through issue-specific in-person discussions led by members of the Engineering, Metering, Customer Service, or other teams. C&I customers can request these discussions by contacting the utility. Aside from regular engagements, the utility's C&I customers are a key source of input for the preparation of the investment plans underlying the DSP, both through meetings and surveys.

Through their technical expertise and highly customized needs, many larger customers provide key information and touchpoints that help calibrate EPI's plans for modifications to system capacity, local grid protection arrangements, or power quality requirements. Beyond their technical acumen, C&I customers offer crucial feedback on the scope, nature, and practical implementation of EPI's Conditions of Service and provide planning insights regarding the trends impacting specific sectors of local economy.

Generators

Generation facilities connected to EPI's distribution grid regularly communicate with the utility's Engineering, Operations and Planning staff to coordinate on necessary outage work and help identify the current or anticipated impact of EPI's activities on their operating needs.

For additional details on EPI's routine customer engagement consultation activities, please see Exhibit 1, Section 1.7.

3.2.1.2 Cost of Service and DSP Engagement and Consultation Activities

Beyond the multiple other modes of ongoing customer interaction and engagement with its customers, EPI, along with its consultant Innovative Research Group ("IRG"), conducted a multi-phase Customer Engagement survey in order to gather customers' needs and preferences to incorporate in its DSP and Cost of Service.

3.2.1.2.1 Phase One

Purpose and Description of the Consultation

In Phase One, EPI and IRG set out to develop a current understanding of customer needs and preferences, and to gain some preliminary insights on more specific investments that could be further explored in Phase Two. Phase One of the engagement focused on understanding the range of views that exist within the customer base and how different types of customers perceive certain issues.

Phase One was in market between June and August, 2024. The survey asked questions about customers' experience with EPI, asked questions to better understand what is most important to EPI's customers (priorities), asked customers about reliability outcomes, and finally asked about specific investments.

Initiation and Participation

EPI provided IRG with a list of all customers for which it had an email address. IRG sent the survey to all unique customers for which an email was provided. For residential and small commercial customers, responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. There were 1,733 (unweighted) EPI residential customers who completed the online survey in Phase One. The residential online survey sample was weighted down to n=1,200 proportionately by consumption quartiles and region in order to be representative of the broader EPI customer base. There were 89 (unweighted) EPI Small Business customers who completed the online survey in Phase One. The Small Business online survey sample was weighted to n=80 proportionately by collapsed consumption quartiles within region in order to be representative of the broader EPI customer base. There were 27 (unweighted) EPI C&I/Large Use customers who completed the online survey in Phase One. Due to the small sample size (n=27), the C&I/Large Use results are not weighted.

Consultation Materials

The IRG Phase One Customer Engagement report is provided in Exhibit 1, Attachment 1-G.

Outcomes and Impact on the DSP

Phase One survey results indicated that most customers are satisfied with the services they receive from EPI. Customers prioritize delivery of electricity at reasonable distribution rates, while also ensuring reliable service. The majority of customers also support necessary investments even if it has a direct impact on their bill. Most customers do not identify immediate service gaps, but when probed, are open to replacing aging infrastructure and making necessary investments. Most customers expressed that they want EPI to invest what it takes to replace the system's aging infrastructure to maintain system reliability, proactively make investments in system capacity infrastructure to ensure customers in high growth areas do not experience a decline in reliability and invest in new technologies to improve reliability or provide other benefits.

EPI will seek to balance reasonable and affordable rates while investing what it takes, including asset renewal and new technologies, to maintain current reliability levels and provide other benefits. In combination with the feedback on Demand Response ("DR") programs (see below), EPI will pursue new supply in St. Thomas in 2025 to address existing constraints in that community.

When it comes to specific initiatives, many customers expressed support for investing in a vegetation management program that uses satellite imaging to build a 3D model of EPI's service territory and lines in order to optimize tree trimming cycles and the scope of tree cutting. Many customers also expressed support for investing in a mobile application to review their account information, see outages and report outages. The majority of customers expressed that they were not likely to enrol in a DR program, particularly industrial customers.

Regarding electricity usage, the majority of C&I and Large Use customers anticipate their planned electricity usage staying relatively the same. Although some C&I and Large Use customers have adopted, or have interest in pursuing EV fleets, EV charging or other renewable energy sources, overall interest from remaining customers was relatively low[3]. Customer adoption of EVs, self-generation and heat pumps in the EPI service territory is occurring and is at early stages.

In response to the feedback gathered during Phase One of customer engagement, EPI made the following adjustments to the plan:

- Tree and Vegetation Trimming: EPI added this program to the draft investment plan and conducted further scoping on the satellite 3D vegetation model program and presented additional investment trade-off details to customers at Phase 2. See Section 3.2.1.2.2 for Phase 2 customer engagement results.
- Customer Mobile Application: EPI added this program to the draft investment plan and conducted further scoping on the customer mobile application program and presented additional investment trade-off details to customers at Phase 2. See Section 3.2.1.2.2 for Phase 2 customer engagement results.
- DR Program: EPI will not pursue a DR program. In combination with the general feedback (see above) EPI will pursue new supply in St. Thomas in 2025 to address existing constraints in that community. See Section 3.2.6.2 for details of the 2025 investment to expand capacity in St. Thomas.
- Electricity Usage: EPI will maintain a paced approach to electrification by monitoring and responding to changing customer electricity needs, such as the adoption of EVs and heat pumps, by planning and building the distribution system for reasonable forecasted load growth, focusing on asset renewal and moving to 100 kVA residential transformer standard. EPI will conduct further scoping and present investment trade-off details to customers on proactive transformer replacement at Phase 2. See Section 3.2.1.2.2 for Phase 2 customer engagement results.

3.2.1.2.2 Phase Two

Purpose and Description of the Consultation

[3] The April 2024 Public Awareness of Electrical Safety Survey with Innovative Research included questions to residents on energy transition. The August 2024 Phase 1 customer engagement feedback is relatively consistent with the results of the April 2024 Public Awareness survey, which showed the following existing DER adoption rates: EVs – approximately 8%, self-generation approximately 8% and heat pumps – approximately 14%. For remaining customers, there was a relatively low level of interest in pursuing EVs and heat pumps, and more interest in pursuing self-generation.

Phase Two Customer Engagement was completed in April 2025. The Phase Two survey presented the overall draft plan and bill impacts and sought feedback on rate harmonization and standby rates, as well as additional detailed investment trade-off questions. Again, random-sampling research methods were used to ensure a representative sample of customers were engaged, ensuring the generalizability of the findings.

Initiation and Participation

EPI provided IRG with a list of all customers for which it had an email address. IRG sent the survey to all unique customers for which an email was provided. A total of 3,692 Residential customers, 114 Small Business customers and 39 C&I customers participated in the survey. For Residential and Small Business customers, responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. Due to the size of the associated rate classes, C&I was not weighted.

Consultation Materials

The Innovative Research Phase 2 Customer Engagement Report is provided in Exhibit 1, Attachment 1-G.

Outcomes and Impact on the DSP

Phase Two survey results indicated that majority of customers support the overall draft plan presented in the survey. In addition, the majority of customers either supported rate harmonization or did not like it but felt it was necessary. Similarly, the majority of customers supported standby rate extension to St. Thomas or did not like it but felt it was necessary.

In terms of specific initiatives, for the targeted reliability investments to improve reliability for those experiencing poorer reliability than average, the majority of customers supported the draft plan level of investment. For the proactive transformer investments to support new uses and demand for electricity, the majority of customers supported investing either at the draft plan level or accelerating spending, with the majority of those supporting accelerated investment in the most at-risk proactive upgrades. For the satellite vegetation management technology, the majority of customers supported investing at the draft plan level or accelerating investment, with the majority of those supporting the draft plan. For the customer mobile application, the majority of customers supported investing at the draft plan level.

EPI responded as follows to the feedback gathered during Phase Two of customer engagement:

- Overall Draft Plan: EPI continued to propose investing at the plan level (except for the proposed proactive replacement of the most at-risk transformers investment adjustment described below)
- Targeted Reliability Investments: Based on the customer feedback, EPI continued to propose targeted reliability investments at the plan level.
- Proactive Transformer Replacement: The initial draft plan included only reactive transformer upgrades. Based on customer feedback, EPI modified the draft plan to propose investment of

an incremental $500k capital per year on proactive replacement of the most at-risk transformers. Please see Attachment J (Capacity Enhancements).

- Tree and Vegetation Trimming: Based on the customer feedback, EPI continued to propose investing for tree and vegetation management satellite technology at the draft plan level. See Attachment J - Miscellaneous System Service and Exhibit 4, Section 4.3.5, Vegetation Control for a description of the Tree and Vegetation Trimming program.
- Customer Mobile Application: Based on the customer feedback, EPI continued to propose investing for the customer mobile application at the draft plan level. See Attachment J, General Plant, IT Software and Exhibit 4, Section 4.3.4 for a description of the Customer Mobile Application.

3.2.2 Subdivision Developers

Purpose of the Consultation

Developer plans can change quickly depending on housing market dynamics, driving major shifts in timing and volume of connection requirements. EPI engages with subdivision developers and industry groups to coordinate long-term planning, keep up with loading trends, and better facilitate the electric power needs of residential expansion in an economic manner.

Initiation and Participation

EPI initiates meetings with developers on an ad hoc, although regular, basis. EPI is also a full member of the Ontario Home Builders Association ("OHBA"), the Chatham-Kent Home Builders' Association and the St. Thomas & Elgin Home Builders' Association, and attends monthly meetings. Meetings are conducted in a mix of in-person and virtual formats.

Description of the Consultation

The meetings provide a venue to share information, resulting in mutual benefits for both EPI and the developer community. Developers offer EPI a clearer view of the nature and volume of future local power demand for its planning activities, while developers benefit from having more direct input and a better-prepared system to connect into.

Consultation Materials

Typically, no formal materials are produced through these engagements. It is mostly verbal insights along with data about schedules or plans.

Outcomes and Impact on the DSP

The following recent information obtained by EPI through developer consultation has informed the DSP:

- **Net Zero Homes** : Certain future developments in the EPI Northeast region will be net zero ready, including requirements for rooftop solar and EV charging rough-ins.
- **Residential Power Capacity Standards**: Previously, the standard was 2 kVA in the northern parts of the service area, including St. Thomas, and 5 kVA in the southern parts, including Chatham-Kent. EPI's new residential standard is now 6 kVA with an option for 12 kVA. This

new standard is being applied across the entire service territory. The design was developed through a combination of discussions with home builders and engineering analysis on current homebuilding trends and system demands associated with DERs. It allows for a level of adoption for these technologies without over constructing before demands have fully materialized. When these requirements do materialize the new design allows additional capacity to be added through cost effective asset upsizing and bus-splitting.

- **Transformer Supply Trends**: In earlier planning cycles (including during pandemic supply chain shortages), developers preferred a turnkey supply of transformers through EPI. Now, developers are opting to purchase transformers themselves rather than through EPI as an intermediary. This trend is most prominent in Chatham-Kent, more so than in St. Thomas. The implication for EPI is an increased requirement for inspection of third-party installations, although with less operational involvement.

3.2.3 Municipalities

Purpose of the Consultation

EPI has regular consultations with municipalities within its service territory to better coordinate major local system changes including customer connections and infrastructure updates.

Initiation and Participation

The municipalities within EPI's service territory include Chatham-Kent, St. Thomas, and Strathroy-Caradoc, North Middlesex, Dutton Dunwich and the Village of Newbury among others. Chatham-Kent holds regular monthly Technical Advisory Committee ("TAC") and ad-hoc municipal planning meetings in which EPI participates. Meetings with other municipalities are less frequent and ad-hoc in nature, with the overall frequency depending on the criticality and number of infrastructure projects being planned or underway at any given time. EPI also makes information requests via email and reviews municipal capital plans.

Description of the Consultation

Chatham-Kent TAC meetings involve sharing information about upcoming civil works impacting the distribution system. The City of St. Thomas prepares a ten-year capital plan, which informs EPI's planning and coordination in this region. EPI also engages with St. Thomas on major industrial impacts, participating in senior level meetings to communication system impacts.

For smaller municipalities, ad-hoc meetings focus on sharing information about capital work, road plans, and other planning impacts. In addition, EPI sent direct letters to the following municipalities informing them of the development of the current DSP:

- Village of Newbury
- Municipality of Dutton Dunwich
- Municipality of North Middlesex (regarding the Community of Parkhill)

A sample letter is provided in Attachment K-1.

Outcomes and Impact on the DSP

The following recent information obtained by EPI through municipal consultations has informed the DSP:

- No municipalities have expressed notable plans for fleet electrification, except for school bus electrification in Strathroy which may require additional infrastructure in the community once plans are finalized.

- Discussions with St. Thomas have included the Volkswagen electric battery production facility, located outside of (and adjacent) to the EPI service territory and scheduled to open in 2027. Some economic spin-off growth is anticipated, although the extent and timing of such remain uncertain. EPI will continue to closely monitor this development

3.2.4 Transmitter

Purpose of the Consultation

EPI coordinates with Hydro One to communicate needs and load trends to ensure adequate higher voltage solutions are in place to enable adequate service to customers.

Initiation and Participation

Consultations take place through the regional planning process and additional supplementary meetings as needed. EPI and Hydro One conduct regular quarterly meetings for general coordination, as well as targeted monthly meetings about specific load requirement issues as needed.

Description of the Consultation

The goal of coordination between EPI and Hydro One is to ensure that as the local customer base grows and load requirements increase, the higher voltage components of the system managed by Hydro One have sufficient capacity to accept these changes. These consultations also allow EPI and Hydro One to coordinate general load requests regarding station, feeder, metering points, and infrastructure relocation.

Consultation Materials

Communication in this venue is facilitated via internal presentations and email.

Outcomes and Impact on the DSP

The following shows a sample of system impacts that have recently been coordinated between EPI and Hydro One and have informed the DSP:

- New customer connection feasibility requests (i.e. new loads and new generation customers).
- St. Thomas area regional planning coordination was completed earlier and off-cycle due to regional load growth driven by the scheduled opening of the Volkswagen battery production

facility in 2027 and related spin off growth, although the extent and timing of such growth remains uncertain.

- Coordination on loading for Wallaceburg TS due to greenhouse growth near Dresden.

3.2.5 Other LDCs

Purpose of the Consultation

Boundaries shared with other distribution utilities present coordination opportunities for system management, build-out, and logistics.

Initiation and Participation

EPI's primary distribution-level neighbor is Hydro One Distribution ("Hydro One Dx"), with whom EPI holds regular meetings. EPI is also an embedded distributor to Hydro One Dx at a significant number of supply points across the EPI distribution system.

EPI is also a participating member of several distribution utility coordination groups, including the Utility Standard Forum ("USF"), Grid Smart City ("GSC"), Ontario Mutual Aid Group ("OnMAG"), and Electrical Distribution Association ("EDA"). Forums for interaction range from formal working groups to ad hoc phone calls as needed.

Description of the Consultation

Consultations with other LDC's and working groups are targeted towards various end goals:

- Hydro One Dx: Discussions and coordination about shared initiatives, preparation for major load changes, and shared equipment usage.
- USF: A forum of Ontario electricity distributors focused on collaboration, mutual support, and industry representation. This includes the establishment of common build standards and best practices.
- GSC: A consortium of local distribution companies ("LDC") and non-LDC partners, collaborating to advance smart grid technologies and energy solutions. In addition to best practice sharing and other initiatives, facilitates purchasing consortium bulk purchases of standard equipment (i.e. transformers, IT solutions) which allows for lower unit costs and shorter lead times.
- OnMAG: A collaborative group of utilities focused on storm response, mutual aid, and enhancing emergency preparedness, including coordination of resources and mutual response to outages and damages arising from adverse weather.
- EDA: The industry association advocating for LDCs, providing policy support, resources, and sector collaboration opportunities. The EDA hosts discussions and coordinates thought leadership about emerging industry issues, regulations, and standards, acting as a centralized intermediary for submitting feedback to the Ministry of Energy and OEB.

Consultation Materials

Communication materials vary depending on coordination group and application.

Outcomes and Impact on the DSP

The following is a sample of recent LDC consultations that have informed the DSP:

- In coordination with Hydro One, EPI is planning to increase capacity and utilization of assets through optimization and sharing of equipment.
    - In 2025, EPI is working with Hydro One to install a new breaker at Edgeware TS, from which EPI will build a new feeder to address existing St. Thomas capacity constraints. See further discussion at Section 3.2.6.2.
    - EPI is also coordinating a new supply point at Mount Brydges in order to meet load growth and support a conversion project. See further discussion at Section 5.1.2.3.3.
- Through GSC, EPI is monitoring industry Distribution System Operator ("DSO") developments and potential requirements. While EPI does not have any DSO specific activity in this DSP, it will continue to improve the sophistication of its systems (i.e. SCADA, back-office systems, telemetry, connectivity models) to continually enhance its operations. Where opportunities present, EPI seeks to work with other LDCs and the IESO.

3.2.6 Regional Planning Process

The EPI service territory extends across four Ontario regional electricity infrastructure planning regions, ensuring frequent engagement in regional planning activities. The four regions hosting EPI infrastructure are:

- London Area;
- Greater Bruce-Huron;
- Chatham-Kent/Lambton/Sarnia; and
- Windsor-Essex.

While logistically challenging, EPI's participation in four separate planning regions enables it to maintain a direct line of contact on the longer-term planning matters with the Independent Electricity System Operator ("IESO"), Hydro One Tx, Hydro One Dx, and all other neighbouring distributors. This DSP is aligned with the outcomes of all four regional planning exercises. The following sections summarize the latest status of regional planning activities and their impact on the current DSP.

3.2.6.1 Summary of Regional Planning Process (All Regions)

Across all regions, EPI supports the regional planning process by contributing updated load forecasts and collaborating on infrastructure solutions. As of June 2025, EPI remains actively engaged in regional electricity infrastructure planning across four Ontario regions:

- London Area
- Greater Bruce-Huron
- Chatham-Kent/Lambton/Sarnia
- Windsor-Essex

This work is being performed with the IESO, Hydro One Transmission and the other distribution companies in each region.

Key findings of the most recent round of planning in these regions which impact EPI include:

- Transformer upsizing at the Tilbury West HVDS scheduled for 2036.
- The 2025 breaker addition at Edgeware TS to mitigate St. Thomas feeder overloads.
- Investments to address Strathroy's projected 10.8 MVA capacity shortfall by 2031.

No immediate needs were identified in the Greater Bruce-Huron IRRP that concluded in 2024. The Chatham-Kent/Lambton/Sarnia report focuses on transmission assets with no direct impact on EPI supply points.

For the London Area, Scoping Assessment phase is currently underway, and EPI is actively participating in regular IESO engagements providing its support, as needed.

Key reports which influence this DSP relating to regional planning are included as attachments:

- The London Area Needs Assessment Report (2024) (Attachment C)
- Greater Bruce-Huron Needs Assessment Report (September 2024) (Attachment D)
- Chatham-Kent/Lambton/Sarnia Regional Infrastructure Plan (August 2022) (Attachment E)
- Windsor-Essex Integrated Regional Resource Plan Report (2025) (Attachment F)

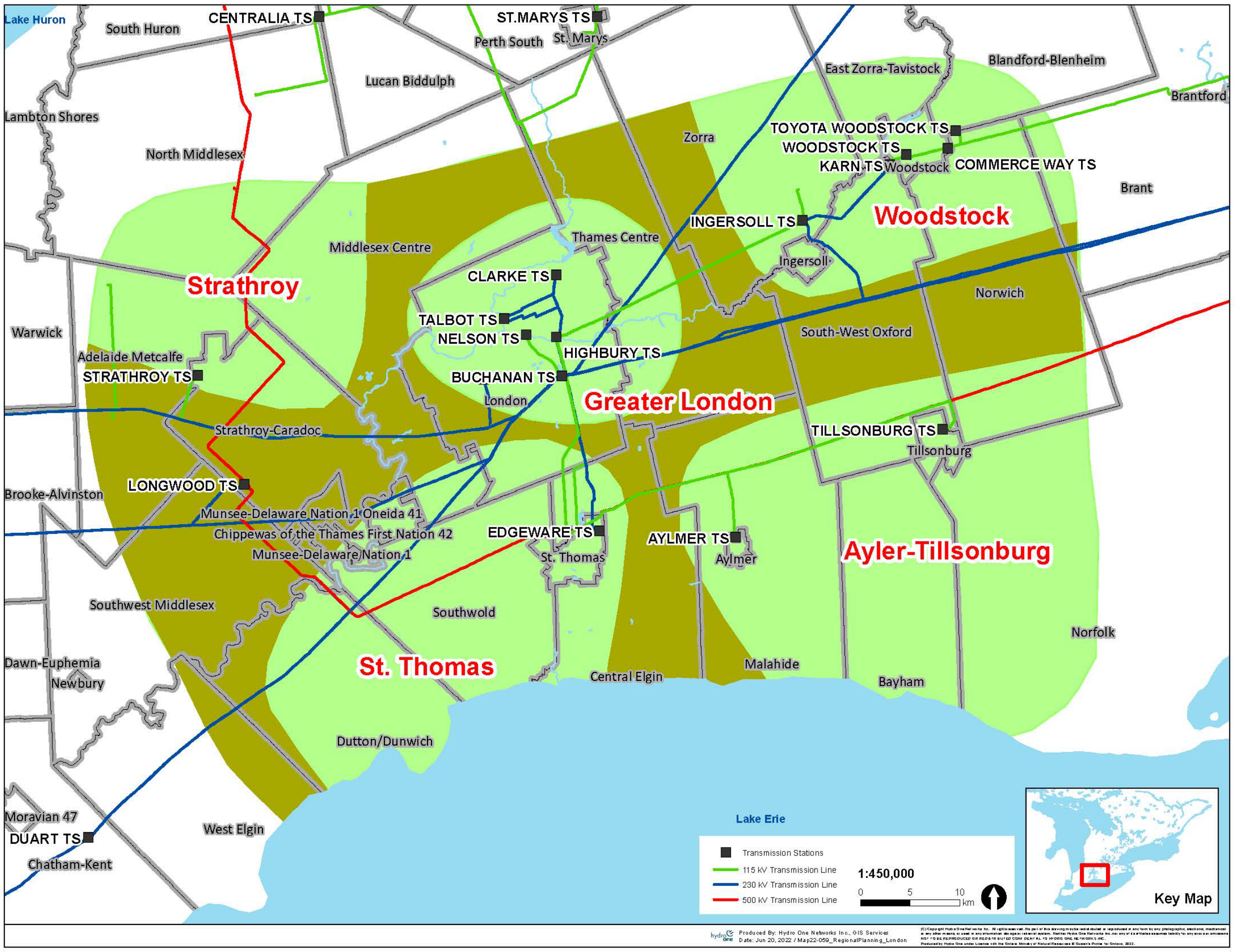
3.2.6.2 London Area Region

The London Area Region is comprised of the Greater London region and five sub-regions as follows:

- Greater London;
- Aylmer-Tillsonburg;
- Woodstock;
- St. Thomas; and
- Strathroy.

EPI territory includes communities in two subregions: City of St. Thomas and Strathroy, as shown in the map below. Recently, EPI contributed to the regional load planning process for the London region, providing detailed gross load forecast estimates at the feeder level for the Strathroy and St. Thomas areas to Hydro One for the period of 2024-2033.

Figure 3: London Area Region and Sub-Region



EPI's load forecast estimate for the St. Thomas and Strathroy regions indicates significant growth by the end of this decade, necessitating investments to expand supply capacities. This is consistent with the growth in the London Area shown in Figure 4 below.

St. Thomas

The community of St. Thomas is served by four dedicated breakers and associated 27.6 kV feeders emanating from Hydro One's Edgeware TS. Recent growth in St. Thomas, driven by residential growth and some industrial expansion, has pushed these four feeders beyond their 14 MW planning capacity. Loading has reached the point where all four EPI feeders are, on average, loaded beyond planning capacity during peak periods. Accordingly, EPI occasionally experiences periods of time in St. Thomas where no transfer capacity remains in the event of certain single points of failure during peak loading, which can lead to extended outages.

Breaker expansion at existing TS's does not constitute part of the typical regional planning process. As described in the 2021 DSP, an investment was planned for 2023 for a new breaker and associated breaker position at the Edgeware TS in St. Thomas. EPI also noted that it was investigating other solutions, which included a DR program that was not supported in Phase 1 customer engagement (see Section 3.2.1.2).

Ultimately, limitations on available capacity at Edgeware TS resulted in this investment being deferred to 2025. In 2025, EPI is working with Hydro One to install an additional breaker at Edgeware TS, from which EPI will build a new emanating feeder to address existing capacity constraints.

Figure 5 below shows this growth in St. Thomas and that another breaker/feeder may emerge near the end of the Forecast Period. The Volkswagen EV battery plant, scheduled to open in 2027 outside (and adjacent) of the EPI's service territory, may drive some economic spin-off in St. Thomas. However, the extent and timing of this impact remain uncertain. EPI will continue to monitor this development.

Strathroy

The remaining capacity at Strathroy TS that supplies the Strathroy region is limited to 10.8 MVA as of April 2025. This represents a significant decrease from the 15.6MVA available at the end of 2023. Under current growth rates the forecasted load growth for this region is projected to exceed this remaining station capacity by 2031. This narrowing margin, especially beyond 2028, highlights the importance of timely investments to ensure adequate capacity to accommodate the region's growing demands. This has been identified as a need in the IESO's regional planning process (see Attachment C - London Area Needs Assessment Report, 2024). Future steps in the ongoing regional planning process will address developing a solution to the need for additional transformation capacity in the area.

Figure 4 below shows the forecasted peak load trends for the St. Thomas and Strathroy regions from 2025 to 2033 (inclusive of the loads of all distributors):

Figure 4: London Area Region Peak Load Forecast

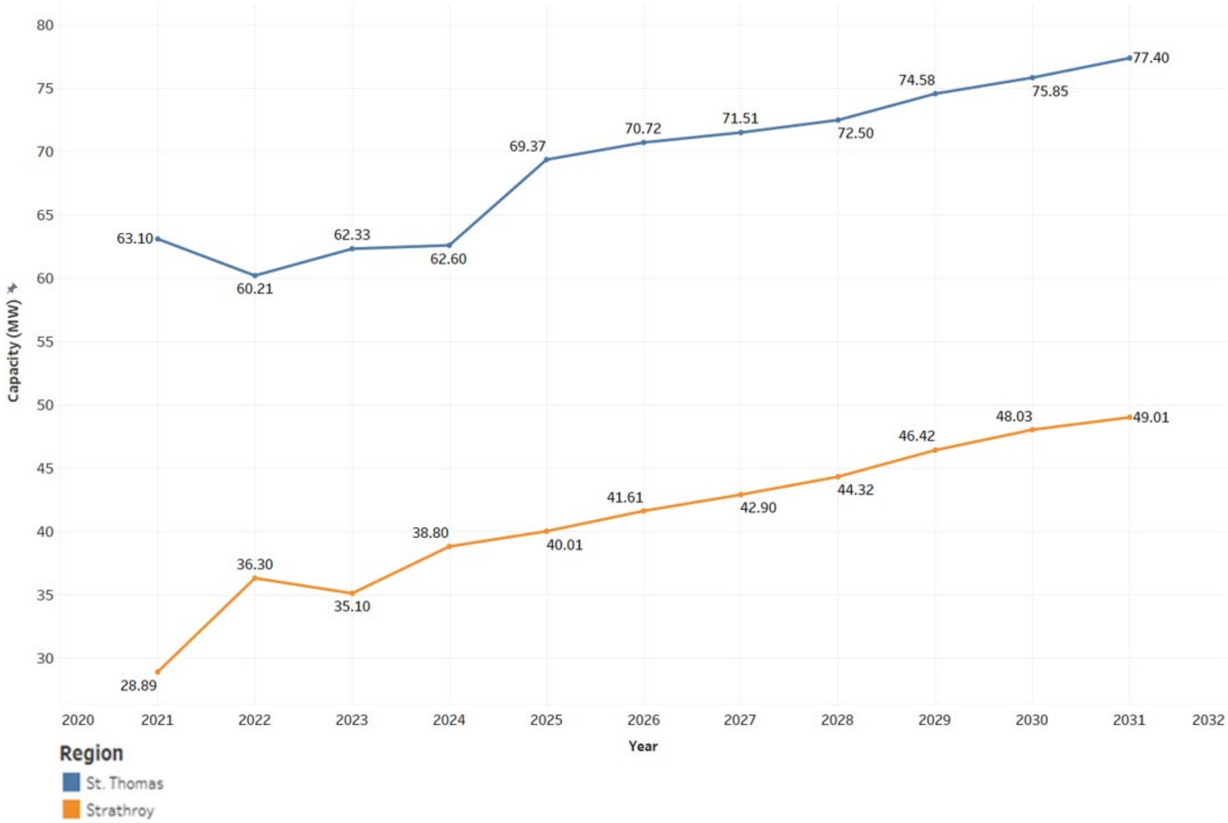
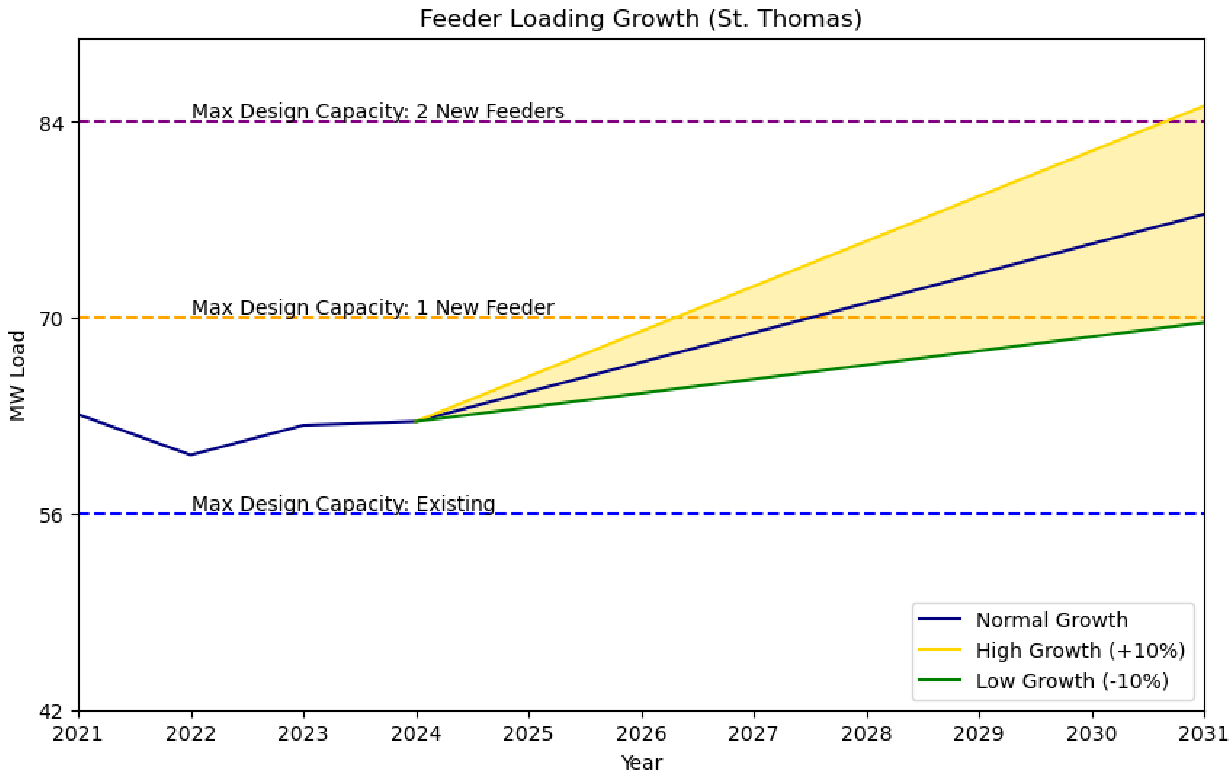


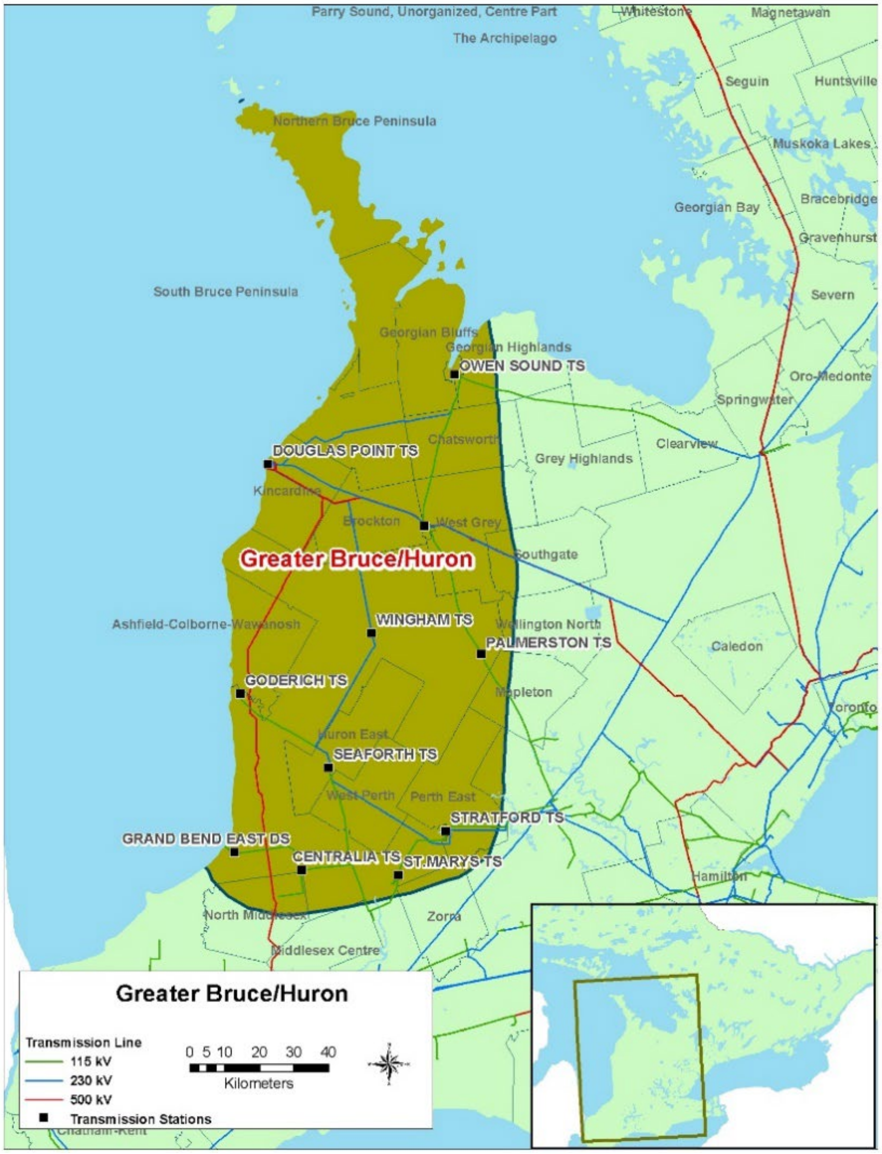
Figure 5: EPI Loading at Edgeware TS (St. Thomas)



3.2.6.3 Greater Bruce-Huron Region

Figure 6 below showcases the planning boundaries for the Greater Bruce-Huron planning area, which includes Hydro One's Centralia TS that feeds the EPI community of Parkhill. The third round of regional planning was initiated in May 2024. The needs assessment has been completed, and no assets impacting EPI were identified as having needs within the planning horizon, concluding EPI's involvement in the process. The needs assessment report was published in September 2024 and is including as Attachment D.

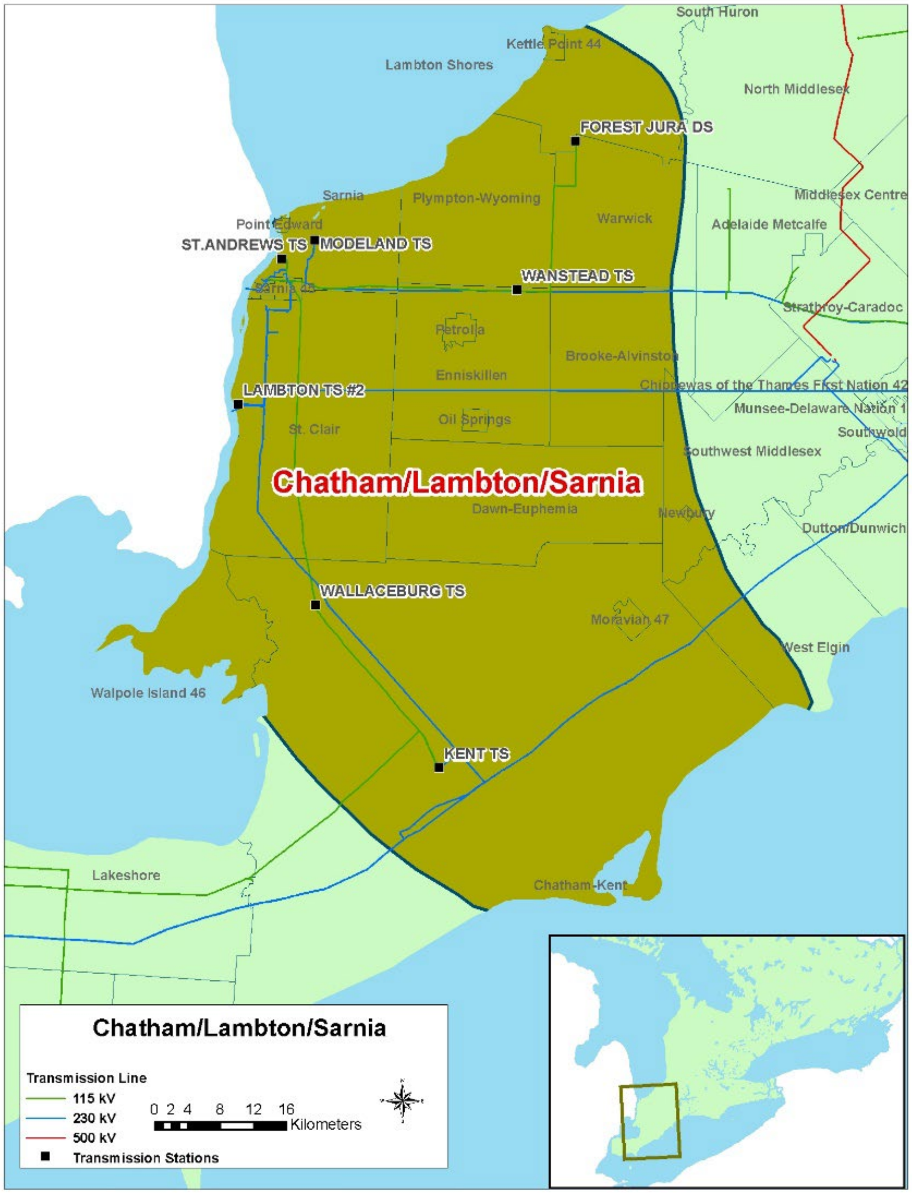
Figure 6: Greater Bruce-Huron Planning Region



3.2.6.4 Chatham-Kent/Lambton/Sarnia Region

This planning region supplies many of EPI's customers, including the cities of Chatham and Wallaceburg as well as several additional towns. Figure 7 below shows the Chatham-Kent / Lambton / Sarnia planning region, which encapsulates a significant portion of EPI's physical service territory. The second cycle of the planning activities in the region concluded in August 2022 with the release of Hydro One's Regional Infrastructure Plan. The report is attached as Attachment E.

Figure 7: Chatham/Sarnia/Lambton Region



The process identified that no IESO Scoping Assessment was required for the integrated resource planning exercise. As such, all subsequent planning work identified in the Needs Assessment was to be completed by Hydro One and the relevant local distributors.

While no EPI-owned assets were directly identified, several identified needs impact stations which act as major supply points to EPI as identified in Section 7.2.1 of the Chatham-Kent / Lambton / Sarnia Regional Infrastructure Plan report. These include:

- Address load growth near community of Dresden through either new TS construction or upgrades to Wallaceburg TS;

- Lifecycle upgrades to Kent TS T2, switchyard and associated equipment.

Although the direct impact to EPI's controlled assets is limited over this planning period, significant investments are being made in the transmission system in this region.

3.2.6.5 Windsor-Essex Region

EPI participated in the regional planning process for the Windsor-Essex area that was initiated by the IESO in 2023. Load forecasts for two of its service territories, Tilbury and Wheatley, were submitted in early in 2024 in support of the regional load forecast.

Figure 8: Windsor-Essex Region

As identified in the current Windsor-Essex IRRP report (April 3, 2025), the Windsor-Essex area has seen significant growth, with many transmission-oriented investments driven by rapid expansion in the agricultural sector and the continued increase in greenhouse activity in the Leamington-Kingsville regions. The IESO identified these regions in their Needs Assessment and IRRP report as likely to face capacity constraints in the short term (1-5 years) and has proposed significant infrastructure upgrades as well as targeted electricity Demand Side Management ("eDSM") initiatives for certain greenhouse facilities. Key plans include the construction of two new 230 kV Dual Element Spot Network ("DESNs") and a double circuit transmission line originating from Lakeshore TS, interconnecting with designated feeders at Leamington TS. These measures are intended to directly enhance system reliability at Leamington TS and support the forecasted load growth in the overall region (see Attachment F).

The community of Wheatley is fed from Leamington TS. While the community's load is not expected to exceed the current capacity in the medium term, adjacent activity is anticipated to continue to pressure the supply capacity in the area until the transmission reinforcement projects recommended in the regional planning report are completed.

The IESO has projected that Tilbury West DS will face long-term station capacity constraints, with a need of 3 MW growing to 13 MW by 2043, as electricity demand increases due to local residential and small-scale industrial growth in the Tilbury area. Additional customer growth could accelerate this timeline, and the current round of regional planning recommends upsizing the transformers at Tilbury West DS to 53 MW LTR by 2036.

3.2.6.6 Overall Impact of Regional Planning Work on the DSP (5.2.2b)

As indicated in the previous sections, EPI actively participates in and coordinates regional planning efforts across many parts of Southwestern Ontario. In the process, EPI has developed and refined increasingly detailed load forecasts for various communities within its service territory, while also providing neighbouring utilities and other stakeholders with understanding of the local distribution system needs. This collaborative approach has historically resulted in coordinated planning in technical decisions and effective investment strategies for capacity and infrastructure upgrades, based on shared data and resources among the participating utilities. EPI has not identified any inconsistencies between this DSP and the current Regional Planning Process.

This DSP does not include any investments in asset or capacity upgrades identified through the latest round of load analysis conducted in the Regional Planning Process. However, as discussed in Section 3.2.6.2, EPI is working with Hydro One on the 2025 installation of a new breaker at Edgeware TS, with EPI constructing a new associated feeder providing approximately 14 MW of additional planning capacity. In addition, the System Service budget proposed in this DSP includes funding for new metering points in the community of Mt. Brydges to bring additional capacity and enable conversion.

Close monitoring of loading conditions will be undertaken going forward for Strathroy TS, Wallaceburg TS, and Tilbury West HVDS. Capacity investments are currently forecast to be needed outside of the 2026-2030 DSP window, but within a 10-year period. The exact timing of these investments could be materially impacted by the pacing of electrification and industrial growth.

3.2.7 Telecommunication Entities (5.2.2.1)

Purpose of the Consultation

EPI has regular consultations with key telecommunication entities operating within its service territory to coordinate ongoing joint-use projects, notify them of EPI capital projects that may impact joint-use customers, and communicate any changes to design standards affecting new applications.

Initiation and Participation

For telecommunication entities with numerous new joint-use attachment projects in progress, EPI often initiates biweekly meetings to review progress. EPI also participates in quarterly meetings of the Accelerated High-Speed Internet Program ("AHSIP") in collaboration with companies such as Xplornet, Bell, Rogers and Teksavvy. Additionally, EPI sends notices as needed regarding capital programs affecting joint-use attachments and changes to design standards via email.

In addition, EPI sent direct letters to eight telecommunication companies operating in the service territory informing them of the development of the current DSP. A sample letter is provided in Attachment K-2. A summary of these engagements are listed below in Table 3-6.

Table 3-6: Summary of Direct Consultations

Date of Consultation	Consultation Overview	Participants
November 2024	Email	Bell
November 2024	Email	Cogeco
November 2024	Email	Execulink
November 2024	Email	NFTC
November 2024	Email	Rogers
November 2024	Email	Start.ca
November 2024	Email	TekSavvy
November 2024	Email	Xplore

Description of the Consultation

In biweekly meetings, the EPI Engineering Department discusses project-specific concerns, such as progress and intended timelines, with representatives of the telecommunication companies. Quarterly AHSIP meetings with Xplornet and NFTC inform EPI about intended projects to ensure they can be completed under government-mandated timelines. EPI also sends out email notices for any planned infrastructure projects that could affect joint-use customers and may require their involvement to move equipment. Any changes to design standards are also communicated via email.

Outcomes and Impact on the DSP

While no specific projects have been identified currently, the planning department considers the scope and timing of known telecommunications projects in the development of capital programs, seeking to maximize the construction efficiency of the combined projects. EPI received some feedback which was considered but did not impact the DSP.

3.2.8 Renewable Energy Generation (5.2.2.2)

EPI submitted a request for letter of comment to the IESO in November of 2024. The IESO reviewed the letter containing EPI's information on the existing REG facilities connected to its system along with the status of the utility's connection queue.

In its response (attached as Attachment G) the IESO notes that EPI has consulted with the IESO. The IESO confirms that EPI has been a participating member of all relevant regional planning activities (which includes participation with the IESO and other applicable distributors). The IESO acknowledges that the EPI REG Plan does not include any investments specific to connecting REG for the Forecast Period 2026-2030. With no required REG investments, the system operator concluded that no letter of comment was required to address the substance prescribed in the OEB's Chapter 5 Filing Requirements, Section 5.2.2.2.

3.3 Performance Measurement for Continuous Improvement (5.2.3)

3.3.1 Distribution System Plan – Previous DSP Objectives (5.2.3.1)

This section outlines the measures tracked by EPI during the previous 2021-2025 DSP period and their relevance to the current DSP. The 2021-2025 DSP objectives and metrics are shown in the table below.

The sections for each individual metric starting beneath the table provides detailed analysis of EPI's performance across key metrics and explanation of the impact to the current DSP, as well as improvements implemented where applicable.

Table 3-7: Summary of Metrics

Line No.	Description	Source	Target
1	**Customer Oriented Measures**		
2	Customer Bill Impacts: Percentage Average Total	Custom	<10%
3	Customer Bill Impacts: Average Dollar Impact	Custom	Monitor
4	System Average Interruption Duration Index (SAIDI) - 5-Year Target	Scorecard	1.42
5	System Average Interruption Frequency Index (SAIFI) - 5-Year Target	Scorecard	1.01
6	System Average Interruption Duration Index (SAIDI) - 4-Year Target	Custom	1.61
7	System Average Interruption Frequency Index (SAIFI) - 4-Year Target	Custom	1.08
8	Customer Average Interruption Duration Index (CAIDI)	Custom	Monitor
9	Momentary Average Interruption Frequency Index (MAIFI)	Custom	Monitor
10	Active Power Quality Investigations	Custom	5/year
11	Worst Performing Feeder	Custom	Monitor
12	**Cost Efficiency and Effectiveness Measures**		
13	DSP Implementation	Scorecard	100% by 2025
14	Planning Quality and Investment Optimization:		
15	Poles, Towers and Fixtures Gross Capital Unit Cost	Custom	Monitor
16	Transformers (excluding station transformers) Gross Capital & Unit Cost	Custom	Monitor
17	Efficiency Results:		
18	Actual vs. Predicted Costs	Custom	Monitor
19	Total Cost per Customer	DSP	Monitor
20	Total Cost per km of Line	DSP	Monitor
21	Total Cost per MW	DSP	Monitor

22	Total CAPEX per Customer	DSP	Monitor
23	Total CAPEX per km of Line	DSP	Monitor
24	Total O&M per Customer	DSP	Monitor
25	Total O&M per km of Line	DSP	Monitor
26	**Asset and System Operations Performance Measures**		
27	Line Losses	Custom	YOY Decrease
28	Defective Equipment Reliability	Custom	Monitor
29	**Safety Measures**		
30	Level of Compliance with O. Reg 22/04	Scorecard	C
31	Non-Occupational Serious Electrical Incidents	Scorecard	0
32	Lost Time Hours	Custom	0

3.3.1.1 Customer Oriented Measures

3.3.1.1.1 Customer Bill Impacts

EPI emphasizes the importance of delivering electricity at reasonable rates to its customers and monitors bill impacts using two measures: (a) Total Dollar Increase (Decrease) per Rate Application, and (b) Percentage Increase (Decrease) per Rate Application. Although the primary focus is on residential bill impacts, EPI monitors bill impacts across all rate classes.

EPIs strives to keep EPI distribution bill impact below 10% (of total bill) for all customer classes to maintain affordable distribution rates. The table below captures the distribution components, as well as commodity charges, retail transmission service rates, and other provincial regulatory changes. Bill impacts are calculated by comparing the average customer bill for a particular rate class at the proposed rates with the average customer bill at the existing rates across typical demand and consumption profiles. For detailed bill impacts, please see the respective IRM Applications as referenced in Table 3-8 below.

Table 3-8: Residential Customer Bill Impacts

Target: EPI distribution bill impact below 10% of total bill

Description	2021 EB-2020-0015	2022 EB-2021-0017	2023 EB-2022-0026	2024 EB-2023-0016	2025 EB-2024-0018
Legacy EPI Rate Zone					
Dollar Impact ($ Increase/Decrease)	$0.53	$0.96	$6.77	$3.20	-$0.41
Percentage Impact (% Increase/Decrease)	0.50%	0.80%	5.80%	2.50%	-0.30%
St. Thomas Rate Zone					
Dollar Impact ($ Increase/Decrease)	$1.82	$1.62	$4.85	$2.86	$0.20
Percentage Impact (% Increase/Decrease)	1.60%	1.40%	4.10%	2.20%	0.20%

Impact on DSP: The relatively low bill impacts (arising from annual IRM applications) reflect EPI's commitment to maintaining affordable distribution rates for customers. More specifically, the majority of the bill impacts proposed for this DSP and the associated 2026 COS Application are below 5%

increases on a total bill basis, and that no rate class exceeds the 10% threshold on a total bill basis as described in Exhibit 1, Section 1.4.9. Having achieved its target during the Historical Period, EPI will continue to monitor bill impacts through the Forecast Period.

3.3.1.1.2 System Reliability

Please refer to Section 3.3.2

3.3.1.1.3 Active Power Investigations

Historically, Power Quality has been a focus area for EPI. In 2016, management established a custom measure alongside a proactive program designed to assist with identified C&I customer power quality concerns annually. This approach ensured that any potential power quality concerns were identified and resolved as quickly as possible. EPI tracked and reported the number of Power Quality investigations completed or ongoing as of December 31 each year.

Table 3-9: Active Power Quality Investigations Results

Target: 5/Year

Description	2021	2022	2023	2024
Active Power Quality Investigations	1	1	0	0

Impact on DSP: The success of this program (i.e. 48 investigations between 2016-2020) has led to a notable decline in customer demand for Power Quality investigations compared to when this measure was instituted in the 2016 DSP and accordingly, the number of investigations has been below target. EPI will stop formally tracking and reporting on this metric but will continue to address Power Quality requests when initiated by customers.

3.3.1.1.4 Worst Performing Feeder (Monitor)

The Worst Performing Feeder ("WPF") monitoring analysis is intended to identify those portions of the distribution system (feeders) that are experiencing sustained interruptions. EPI catalogs the reliability (i.e. SAIDI/SAIFI/CAIDI) performance of each of its 27.6kV feeders on a 3-year rolling average. This involves tracking outage information and associating it with the feeder that suffered the associated outage.

EPI uses this analysis to maintain and improve the system-wide SAIDI/SAIFI/CAIDI and measures success against achieving those specific targets. Feeders with the worst reliability performance are then identified and studied to identify the root cause(s) of the poor reliability. Once the analysis is complete, targeted remediations can be scheduled. This may involve the development of asset renewal projects, smart grid projects, additional vegetation management, or any number of other solutions depending on the determined cause.

The table below is an example, depicting worst performing feeders in 2024 based on SAIDI & SAIFI metrics.

Table 3-10: Worst Performing Feeder

SAIDI Rank (Target 1.61)			
2024: SAIDI			
Feeder	**SAIDI**	**Ranking**	**Change in Rank**
1M2	4.7736	1	↑+9
27M5	4.1266	2	↑+21
1M6	3.2593	3	↑+8
5M17	2.5818	4	↑+21
24M4	2.5698	5	↑+8
DTF1	2.0280	6	↑+25
5M4	1.5602	7	↑+11
5M3	1.3848	8	↑+6
29M2	1.2518	9	↓-7
5M15	1.1701	10	↑+9
5M22	1.0177	11	↑+5
5M16	1.0115	12	↓-11
5M7	0.9973	13	↓-8
27M10	0.9629	14	↑+7
MBF3	0.8558	15	↑+2
27M1	0.8281	16	↑+11
BOF1	0.7757	17	↓-8
5M21	0.6116	18	↓-10
5M8	0.5303	19	↑+3
1M5	0.3759	20	↓-14
29M4	0.2610	21	↓-9
393M22	0.1840	22	↑+11
TDSF1	0.1511	23	↓-16
ERF2	0.1113	24	↓-21
52M24	0.0506	25	↑+5
27M6	0.0467	26	↓-6
TDSF2	0.0389	27	↓-23
1M1	0.0253	28	↑+1
MEF3	0.0139	29	↓-14
NBF2	0.0045	30	↓-2

SAIFI Rank (Target 1.08)			
2024: SAIFI			
Feeder	**SAIFI**	**Ranking**	**Change in Rank2**
1M2	5.1000	1	↑+25
1M6	3.3028	2	↑+1
27M5	3.2143	3	↑+18
5M4	3.1435	4	↑+9
5M21	3.0792	5	↑+1
24M4	2.1082	6	↑+16
5M17	1.9875	7	↑+20
5M22	1.5838	8	↑+3
5M7	1.3743	9	↓-8
1M5	1.2443	10	↓-5
5M3	1.1845	11	↑+1
DTF1	1.1525	12	↑+21
27M1	1.1133	13	↑+16
29M2	1.0413	14	↓-12
5M15	0.9177	15	↑+9
5M8	0.8658	16	↓-6
5M16	0.6163	17	↓-13
BOF1	0.5791	18	↓-9
27M10	0.5393	19	↓-4
MBF3	0.3868	20	↓-1
29M4	0.2331	21	↓-7
NBF2	0.1991	22	↑+10
27M6	0.1913	23	↑+5
393M22	0.1393	24	↑+6
ERF2	0.0702	25	↓-9
TDSF2	0.0467	26	↓-18
1M1	0.0410	27	↑+4
TDSF1	0.0332	28	↓-21
52M24	0.0139	29	↓-9
MEF3	0.0092	30	↓-7

Impact on DSP: Through the historical period, EPI monitored WPF and utilized the metric as an input into capital investment planning. WPF monitoring has helped inform decisions related to feeder segmentation and smart grid projects, helping target areas for focused pole testing and subsequent replacements, and serving as a benchmark for assessing the effectiveness of tree trimming activities. Going forward, EPI will continue to utilize annual Worst Performing Feeder data as a factor in prioritizing capital programs.

3.3.1.2 Cost Efficiency and Effectiveness Measures

3.3.1.2.1 Distribution System Plan Implementation Progress

This metric was calculated by dividing net capital expenditures by the aggregate total DSP (5-year) capital expenditures.

Table 3-11: DSP Implementation Results

Target: 100% by Dec 31, 2025

Description	2021	2022	2023	2024
DSP Implementation	20%	41%	62%	88%

Impact on DSP: DSP Implementation provides a snapshot of DSP execution progress which helps management recognize its headway on DSP achievement. EPI will attain 100% by the end of the 2021-2025 DSP window. This is also a scorecard metric and EPI will continue to track it on an annual basis with a goal of attaining 100% by the end of the DSP 2026-2030 window.

3.3.1.2.2 Planning Quality and Investment Optimization

Table 3-12: Poles, Towers and Fixtures Gross Capital Unit Cost

Target: Monitor

Description	2021	2022	2023	2024
Poles, Towers and Fixtures Gross Capital Unit Cost	$7,763	$ 8,511	$ 8,364	$8,029

EPI tracks the average cost of Poles and Tower structures and updates these values annually as part of its budget development process. This metric was introduced as part of the 2021 DSP, so data is tracked from 2021 forward. It considers the total cost for all pole related items, including labour, materials, equipment time, and designing, as well as the number of new poles installed for the year.

While it would typically be expected that pole unit costs increase over the Historical Period in line with inflation and broader supply chain pressures, the data in Table 3-10 does not show a consistent upward trend. Instead, unit costs peaked in 2022 and have since declined slightly, particularly in 2024. This counterintuitive trend can be explained by several atypical factors that distorted the historical averages.

In 2021 and 2022, a large portion of spending on poles was driven by Make Ready Work caused by increased volume of ISPs as described in Section 3.1.2.1. These projects involved pole inspections and subsequent repairs and upgrades to pole fixtures such as insulators and guywires. While these costs were attributed to poles, they did not involve actual pole installations and, as a result, the total capital spend was spread over a much smaller number of new pole installations, impacting the unit cost.

2023 experienced a higher-than-usual volume of emergency work as seen by numerous weather-related Major Event Days (“MEDs”) described in Section 3.3.2.4. Emergency pole replacements often incur higher unit costs due to unplanned mobilization and after-hours labour. This further complicates comparatives.

Impact on DSP: In addition to the dynamics discussed above, it is evident that EPI has been facing inflationary cost pressures over the Historical Period, which is consistent with global supply chain disruptions initially caused by the pandemic, leading to the inflationary trends shown in Figure 2. In addition to the inflationary cost pressures, it is evident that the poles, towers and fixtures gross capital unit cost is dependent on many factors.

See additional discussion under Section 3.3.1.2.3 (Efficiency Results) below.

Table 3-13: Transformers Gross Capital and Unit Cost

Target: Monitor

Description	2021	2022	2023	2024
Transformers (Excluding Station Transformers) Gross Capital and Unit Cost	$10,269	$7,422	$12,119	$17,666

EPI tracks the average cost of transformers and updates these values annually as part of its budget development process. This metric was introduced as part of the 2021 DSP, so data is tracked from 2021 forward. It considers the total cost for all transformer related items, including labour, materials, equipment time, and designing, as well as the number of new transformers installed for the year.

Transformer sizes can vary from 25 kVA to 1,500 kVA dependent upon the type and density of customer load (e.g., residential, commercial, or industrial), expected peak demand, and the configuration of the electrical system at the installation site, including the number of customers served per transformer and the nature of the secondary distribution. Transformer cost can vary substantially with transformer size, making unit cost results highly dependent upon the mix of transformer sizes installed in a given year. For example, in 2022 the unit cost decreased since a relatively higher percentage of lower kVA transformers were installed than 2021. Additionally, in 2024, a higher proportion of 100 kVA transformers were installed, consistent with the late-2023 adoption of 100 kVA transformers as the standard for residential distribution. See Section 4.1.2 for additional details.

Impact on DSP: In addition to the above-noted mix explanation, including the adoption of 100 kVA transformers for residential distribution, it is evident that EPI has been facing inflationary cost pressures over the Historical Period, which is consistent with global supply chain disruptions initially caused by the pandemic, leading to the inflationary trends shown in Figure 2. See additional discussion under Section 3.3.1.2.3 (Efficiency Results) below.

3.3.1.2.3 Efficiency Results

Table 3-14: Actual vs. Predicted Econometric Total Costs

Target: Monitor

Description	2021	2022	2023	2024
Actual vs. Predicted Econometric Total Costs	(28.7%)	(27.0%)	(27.8%)	(27.8%)

EPI began tracking the OEB's efficiency measures at inception in approximately 2008. Actual vs. Predicated Econometric Total Costs (along with the Total Cost per Customer Measure and the Total Cost per kM of Line Measure) are based on a statistical total cost benchmarking study. The study is designed to make inferences on the cost efficiency of individual distributors based on econometric modeling conducted by an OEB consultant, which is used to predict the level of costs associated with each distributor's operating conditions. The distributor's actual cost is then compared to that predicted by the model. The percentage difference between actual and predicted cost is the measure of cost performance. Companies with larger negative differences between actual and predicted costs are considered better cost performers

Impact on DSP: Since before 2021, EPI has consistently achieved a large negative difference between actual and predicted costs, which has resulted in EPI being ranked in the first Total Cost Benchmarking efficiency cohort (the most efficient tranche). Before 2021, EPI was ranked in the second efficiency cohort. Costs are increasingly driven by the need to provide modern, reliable service to growing communities and to adapt to evolving industry requirements, including the deployment of new technologies while ensuring that service quality metrics are met or exceeded. Despite significant inflationary pressures in recent years, driven in part by global supply chain disruptions, as well as ongoing asset renewal and modernization needs, EPI's total costs have remained well below those predicted by the OEB consultant's current econometric model. EPI remains committed to maintaining efficiency while investing prudently where necessary to meet evolving customer needs and sustain service, even if such investments may increase costs compared to historical levels.

Table 3-15: Total Cost per Customer

Target: Monitor

Description	2021	2022	2023	2024
Total Cost per Customer – with econometric adjustment	$558	$627	$713	$748

Similar to the previous measures, Total Cost per Customer is an econometric metric based on a statistical total cost benchmarking study commissioned by the OEB. For this measure, each distributor's Total Costs (including O&M and Admin costs) are divided by the number of customers applicable to each distributor (including certain adjustments to make the costs more comparable between distributors). Accordingly, the econometric results above do not equate to simply dividing Total Cost by Customers.

Impact on DSP: See discussion under 3.3.1.2.3, Efficiency Results above.

Table 3-16: Total Cost per KM of Line

Target: Monitor

Description	2021	2022	2023	2024
Total Cost per KM of Line – with econometric adjustment	$10,670	$11,977	$13,731	$14,447

Similar to the previous measures, Total Cost per km of Line is based on an econometric total cost benchmarking study commissioned by the OEB. For this measure, each distributor's Total Costs (including O&M and Admin costs) are divided by the km of line applicable to each distributor (including certain adjustments to make the costs more comparable between distributors). Accordingly, the econometric results above do not equate to simply dividing Total Cost by Customers.

Impact on DSP: See discussion under Section 3.3.1.2.3 Efficiency Results above.

Additional Cost Metrics

Starting with the 2021-2025 DSP, EPI also began to monitor the following metrics (none of which include econometric adjustments): Total Cost per MW, Total Capex per Customer, Total Capex per KM of Line, Total O&M Per Customer, Total O&M Per KM of Line. OEB Open Data is used to gather the information required for the calculations. The Capex amount is net of contributed capital and the O&M costs are operations and maintenance only. Where data was available prior to 2021, EPI has provided prior period data in the results below.

Table 3-17: Additional Cost Metrics

Target: Monitor

Year	Cost Metric	CAPEX Metrics		O&M Metrics		Total Cost Metrics	
	Total Cost Per MW	**Capex Per Customer**	**Capex Per KM of Line**	**O&M Per Customer**	**O&M Per KM of Line**	**Cost Per Customer**	**Cost Per KM of Line**
2019	$ 76,100	$ 170	$ 3,297	$ 73	$ 1,408	$ 243	$ 4,705
2020	$ 91,071	$ 217	$ 4,330	$ 65	$ 1,302	$ 283	$ 5,632
2021	$ 96,514	$ 231	$ 4,428	$ 75	$ 1,439	$ 307	$ 5,867
2022	$ 98,807	$ 227	$ 4,329	$ 85	$ 1,616	$ 311	$ 5,945
2023	$ 103,133	$ 234	$ 4,511	$ 88	$ 1,705	$ 323	$ 6,216

Impact on DSP: It is evident that EPI has been facing inflationary cost pressures over the Historical Period, which is consistent with global supply chain disruptions initially caused by the pandemic, leading to the inflationary trends shown in Figure 2.

See discussion under Section 3.3.1.2.3 Efficiency Assessment above.

3.3.1.3 Asset and System Operations Performance Measures

3.3.1.3.1 Line Losses

Line loss is calculated as the percentage of electrical energy lost due to heat and transformer losses during the transmission of electrical energy from the supply points of Hydro One or the IESO grid to EPI's customers. By focusing on reducing line loss, EPI can ensure more efficient distribution of electricity and reduce customer bill costs. Line losses naturally vary from year to year depending on system configuration and utilization levels. Therefore, it is best viewed as a long-term smoothed indicator of system performance.

Table 3-18: Line Losses

Target: Year-over-Year Decrease

Description	2021	2022	2023	2024
Line Losses	3.81%	3.71%	3.84%	3.82%

Impact on DSP: EPI strives for a year-over-year decrease in line losses. Although results remained relatively stable, a consistent decrease did not occur, primarily due to System Access demand priorities that deferred certain Voltage Conversions into the latter part of the Historical Period. See additional details in Section 5.1.1.1.2. Moving forward, EPI's plan to achieve this goal includes both capital investments in its system, such as Voltage Conversion of lower, legacy voltage feeders to 27.6 kV and decommissioning distribution stations, and ongoing distribution system investment and maintenance. See Section 4.1.1.1 for details on the new Voltage Conversion metric for the 2026-2030 DSP, which will assist in line loss reduction.

3.3.1.3.2 Defective Equipment Reliability

EPI continues with significant investment in its distribution system and associated maintenance activities as described throughout this DSP. Investment in System Renewal is essential for addressing aging infrastructure, maintaining safety compliance, and ensuring a safe work environment. While it is a key area of investment needed to maintain reliability, these investments represent long-term, slow-moving change, and do not always yield immediately noticeable improvements. EPI has been increasing its investment into system renewal over the previous DSP period, and continues to do so over the forecast window to address pressure within this monitoring measure. EPI's strategy balances long-term resilience, growth, and affordability, ensuring that renewal supports future reliability even if short-term gains are not always immediately apparent.

As this is a recently added metric for EPI, historical data from the 2021 DSP Historical Period has also been shown below.

Table 3-19: Defective Equipment Reliability

Target: Monitor

Description	2021	2022	2023	2024
Average Number of Hours that Power to a Customer is Interrupted due to Defective Equipment	0.32	0.41	0.61	0.47
Average Number of Times that Power to a Customer is Interrupted due to Defective Equipment	0.24	0.45	0.44	0.44

Impact on DSP: The purpose of this metric is to visualize the direct effect of System Renewal investments on customer experience. In 2021, the impact of EPI's ongoing investments to address aging infrastructure was visible as a significant decline in interruption duration and frequency was noted versus previous years as distribution automation equipment began to be deployed in troubled areas. Over both the historical and forecast periods, EPI is continuing to accelerate spending on system renewal to address this deteriorating metric.

3.3.1.4 Safety Measures

3.3.1.4.1 Level of Compliance with Ontario Regulation 22/04

The DSP and scorecard safety metric "Level of Compliance with O. Reg 22/04" measures distributor compliance with objective-based electrical safety requirements related to the design, construction, and maintenance of distribution systems licensed by the OEB. The regulation requires distributors to obtain approval of equipment, plans, specifications, and inspection of construction before putting systems into service. Third-party audits are conducted to ensure compliance. EPI is fully compliant with O. Reg 22/04.

Table 3-20: Level of Compliance with O. Reg 22/04 Results

Target: Compliant

Description	2021	2022	2023	2024
Level of Compliance with O. Reg 22/04	Compliant	Compliant	Compliant	Compliant

Impact to DSP: EPI has been compliant with O.Reg 22/04 throughout the Historical Period and will continue to target annual assessments of "compliant" to ensure public safety.

3.3.1.4.2 Non-Occupational Serious Electrical Incidents

The Non-Occupational Serious Electrical Incident Index is a key component of EPI's public safety measures, aimed at enhancing electrical safety on the distribution network over time. This metric tracks the number and rate (per 1,000 km of line) of serious electrical incidents on EPI's system. EPI aims to achieve zero such incidents annually.

Table 3-21: Non-Occupational Serious Electrical Incidents Results

Target: 0

Description	2021	2022	2023	2024
Non-Occupational Serious Electrical Incidents	1	1	0	1
Rate per 1,000km of Line	0.329	0.311	0.00	0.306

In 2023 there were no serious electrical public incidents. In 2024, the incident involved animal contact with an overhead line that caused the line to fall to the ground; there were no injuries to the public. From 2021 to 2022, public incidents included weather-related vegetation contact causing conductor phase breaks and a member of the public contacting a distribution line while tree-trimming. Fortunately, no injuries were reported. Following these incidents, management conducted reviews and implemented corrective actions to enhance public safety.

Impact to DSP: Moving forward, EPI will continue to target zero incidents and will maintain its commitment to public and electrical safety awareness through targeted media and advertising initiatives, supplemented by contractor and first responder training, as well as educational outreach in classrooms and to specific community groups. Additionally, EPI will continue conducting its biennial Public Awareness of Electrical Safety Survey to assess safety engagement (the 2024 survey is provided as Attachment L).

3.3.1.4.3 Lost Time Hours

EPI was an early utility adopter of the IHSA COR certification in 2015. EPI puts significant focus on maintaining its IHSA COR certification (now COR 2020), which drives continuous safety system and process improvement. EPI's COR-based safety process is both a commitment and an investment to keep EPI's employees safe.

EPI maintains a comprehensive safety program overseen by the EH&S Committee of the Board of Directors, which reviews annual safety objectives and training plans, with Board members and senior leadership conducting frequent crew visits. A Joint Health and Safety Committee ("JHSC") ensures safety practices are integrated across all operating centers. An active safety concern program, whereby employees submit concerns for management and JHSC follow-up, has been in place since 2012. EPI supports industry training by hosting the regional IHSA Apprentice Training Program at its Chatham Operational Centre. Safety is also reinforced through daily and quarterly meetings, proactive reporting, and frequent worksite visits by management and JHSC members. A structured training program addresses key operational risks, including utility work protection, confined space rescue, and hazardous material handling, alongside WHMIS, workplace violence prevention, and accessibility training. EPI enforces contractor safety compliance through third-party evaluations and direct monitoring. Public safety initiatives include school and community outreach, first responder electrical safety training, and farm safety programs. These efforts foster a culture of continuous improvement in workplace and public safety.

Historically, EPI has measured Employee Health & Safety ("EH&S") by tracking Lost Time Hours, which occur when an employee gets injured while carrying out a work task for the employer and is unable to perform the regular duties for a complete shift. EPI measures Lost Time Hours through a review of statement of claim summaries provided by the Workplace Safety and Insurance Board ("WSIB"). EPI's goal is to have zero Lost Time Hours each year.

Historical reporting of Lost Time Hours results is shown below:

Table 3-22: Lost Time Hours Results

Target: 0

Description	2021	2022	2023	2024
Lost Time Hours	0 hrs	72.0 hrs	72.0 hrs	37.5 hrs

EPI recognizes that, despite dedicated efforts to maintain the highest EH&S standards, workplace injuries may still unfortunately occur. The Lost Time Hours shown above involved an employee contracting COVID-19 (2022), an employee injured while unloading a truck (2023) and an employee colliding with a door frame (2024). Post recovery, these employees were able to resume full duties. Following these incidents, management conducted reviews and implemented additional corrective actions, where necessary, to further enhance employee safety. This contributed to the decision to implement the next stage of COR certification (the COR 2020 accreditation) in 2024.

Impact to DSP:

Moving forward, EH&S will be measured by leading indicators, rather than Lost Time Hours. Three specific metrics will be tracked:

- Number of safety concerns submitted by employees
- Number of crew in-field visits conducted by senior leadership and board members
- IHSA COR audit score

3.3.1.5 Additional Objectives Outlined in the Previous DSP

Section 2.1.1 of the previous DSP lays out EPI's additional objectives and goals for the 2021-2025 period. The following items are highlighted in that document:

- Section 2.1.1.1 of the 2021 DSP identifies the closure of the Strathroy service center as a pending task. This work was successfully completed, with office staff relocated to the St. Thomas office. EPI still maintains an equipment storage facility in Strathroy to assist with timely access to materials and equipment for communities in the Northwest portion of its service territory, including Parkhill. Through the office closure, EPI was able to reduce the annual

Strathroy lease amount by $87k annually, starting in 2023, while achieving more critical mass of management and staff at a consolidated, harmonized facility owned by EPI. This section also identified some remaining post-merger inconsistencies in asset management data collection which have since been resolved. See Section 4.1.2 for further discussion.

- Section 2.1.1.2 of the 2021 DSP identifies legacy low-voltage infrastructure and the ongoing need for voltage conversion as a key issue. The issues identified in this section around capacity, asset condition, and renewal needs remain in place, and are a key theme of this DSP as well. In the 2021 DSP, there was approximately 347 km of legacy voltage underground cable, and 21 substations. Section 4.1.3.2 of the 2021 DSP discussed a customer preference for a "faster pace scenario for Voltage Conversion", which resulted in increasing the number of low voltage station decommissions from 4 to 5 over the 2021-2025 Forecast Period. At the end of 2024, there was approximately 187 km of underground cable and 16 substations remaining in service, meeting the 2021 DSP target of 5 substation decommissionings and exceeding internal targets for cable conversion. The accelerated cable conversion was driven by the progress toward station decommissioning, as much of the overhead equipment had already been converted prior to the historical window. See Section 5.1.2.2.1 for further discussion about EPI's plans for voltage conversion over the forecast period.
- Section 2.1.1.3 of the 2021 DSP addresses EPI's focus on maintaining reliability. See Section 3.3.1.1.2 for a further discussion on reliability.
- In Section 2.1.1.4 of the 2021 DSP, EPI discusses the key issue of capacity planning. Coming off a period of higher customer growth, major supply chain disruptions, and significant budgetary stress due to inflation, EPI has increased its efforts around capacity planning over the historical period as system utilization levels have increased due to customer growth. The nature of customer growth has also seen anecdotal changes over the historical period, with larger capacity requests becoming more common. EPI intends to continue efforts to improve its capacity planning capabilities over the forecast period, developing significant additional analysis tools to track load growth in fine granularity across its service territory (See Section 3.2.6). Over the historical period, EPI has begun tracking station capacity in greater detail to ensure capacity is available to support ongoing growth. See Section 4.4 for discussions about EPI's capacity planning activities over the forecast period.
- Section 4.1.3.2 of the 2021 DSP discussed a customer preference for a higher density of automated switch installations in Chatham and St. Thomas in 2024 and 2025. It was noted that this project would be re-examined in 2024 based on prevailing circumstances at that time, including reliability metrics and the level of capital requirements at that time. Based on reliability metrics (see Figure 12) and capital needs in 2024 and 2025, EPI completed the Chatham switch installations and deferred the St. Thomas switch installations to the 2026-2030 Forecast Period.

3.3.2 Service Quality and Reliability (5.2.3.2)

3.3.2.1 Service Quality Requirements

EPI measures and monitors service quality in accordance with its core values of Customer and Community Focus and Operational Excellence. EPI tracks and reports on SQRs in accordance with Chapter 7 of the DSC. Table 3-23 below presents EPI's SQR performance for the historical period. EPI confirms this data is consistent with its scorecard and consistent with OEB Chapter 2 Appendix 2-G (see live excel version of Chapter 2 Appendices ((EPI_2026_Filing_Requirements_Chapter2_Appendices_1.0_20250829)).

Table 3-23: Service Quality Metric Results

Indicator	OEB Minimum Standard	2020	2021	2022	2023	2024
Low Voltage Connections	90.0%	96.91%	97.60%	98.55%	98.55%	97.89%
High Voltage Connections	90.0%	100.00%	n/a	n/a	100.00%	100.00%
Telephone Accessibility	65.0%	79.11%	81.26%	68.42%	83.75%	76.56%
Appointments Met	90.0%	99.83%	99.71%	100.00%	99.96%	99.96%
Written Response to Enquires	80.0%	93.76%	95.48%	100.00%	100.00%	100.00%
Emergency Urban Response	80.0%	94.29%	93.10%	94.74%	94.74%	91.30%
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	2.67%	1.76%	2.94%	1.09%	1.43%
Appointment Scheduling	90.0%	93.46%	72.03%	73.72%	91.82%	99.34%
Rescheduling a Missed Appointment	100.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Reconnection Performance Standard	85.0%	100.00%	100.00%	98.87%	99.39%	99.73%

EPI's results demonstrate its commitment to operational excellence for its customers and the communities it serves. EPI has exceeded the performance targets for all but one metric during each of the past five years.

In 2021 and 2022 EPI fell below the performance target on Appointment Scheduling. The specific component area where the requirement was not met was with respect to locate appointments. EPI employs a mix of in-house resources and third-party services to complete locates. In both 2021 and 2022, locate volumes were elevated in the EPI service territory due to economic activity, including high-speed internet access expansion and increased housing starts. Simultaneously, the third-party service provider experienced a backlog due to labour market challenges, including high turnover and staff retention, which resulted in response delays. See Exhibit 4, Section 4.3.6 ("Cable Locates") for details on mitigating actions taken by EPI to address locate appointments and the legislative changes introduced through Bill 93, Getting Ontario Connected Act, 2022.

3.3.2.2 Reliability Requirements

EPI uses the following measures to monitor its reliability across the distribution system:

- System Average Interruption Duration Index ("SAIDI");
- System Average Interruption Frequency Index ("SAIFI");
- Customer Average Interruption Duration Index ("CAIDI"); and,
- Momentary Average Interruption Frequency Index ("MAIFI")

SAIDI is the average outage duration that is experienced by each customer in the distribution system. The index is calculated by dividing the sum of all customer hours of sustained interruptions over a year by the total average number of customers served.

SAIFI is the average number of interruptions experienced by each customer. SAIFI is calculated by dividing the total number of customer interruptions by the total average number of customers served.

CAIDI is the average time for service to be restored for each customer after an outage has occurred. CAIDI is calculated by dividing SAIDI by SAIFI.

MAIFI is the average number of momentary interruptions experienced by a customer. A momentary interruption is defined as an interruption that lasted less than 60 seconds. MAIFI is calculated by dividing the total number of momentary customer interruptions by the total average number of customers served.

Because of EPI's highly embedded nature, reliability is tracked, and spending decisions are informed by these statistics both including and excluding Loss of Supply ("LOS") events and MEDs. The table below presents the overall reliability results for EPI.

Table 3-24: Overall Reliability Performance Statistics

Description	2020	2021	2022	2023	2024
All Cause Codes					
Memo: Major Event Days (MEDs)	0	0	1	4	1
SAIDI	2.22	2.87	4.46	8.32	2.70
SAIFI	1.74	2.01	2.92	2.47	2.75
CAIDI	1.27	1.42	1.53	3.37	0.98
MAIFI	4.21	3.31	2.73	3.53	3.60
Excluding LOS					
SAIDI	1.47	1.09	2.78	6.98	1.50
SAIFI	1.18	1.02	1.42	1.57	1.57
CAIDI	1.25	1.07	1.96	4.44	0.96
MAIFI	2.98	2.69	2.02	3.06	2.99
Excluding LOS and MED					
SAIDI (2020 Target: 1.16; 2021-2025 Target: 1.42)	1.47	1.09	1.76	1.31	1.26
SAIFI (2020 Target: 0.87; 2021-2025 Target: 1.01)	1.18	1.02	1.18	0.93	1.48
CAIDI	1.25	1.07	1.49	1.41	0.85
MAIFI	2.98	2.69	2.02	2.77	2.99

3.3.2.3 Historical Service Quality and Reliability Metrics

EPI did not meet the SAIDI target in 2020 and 2022, primarily due to the combined effects of aging infrastructure (as reflected by the Defective Equipment metric shown at Section 3.3.1.3.2), enhancements to the outage reporting system, and substantial weather-related outages that did not reach the OEB's MED threshold for normalization. These sub-MED storms caused substantial service interruptions, which are reflected in the reported results.

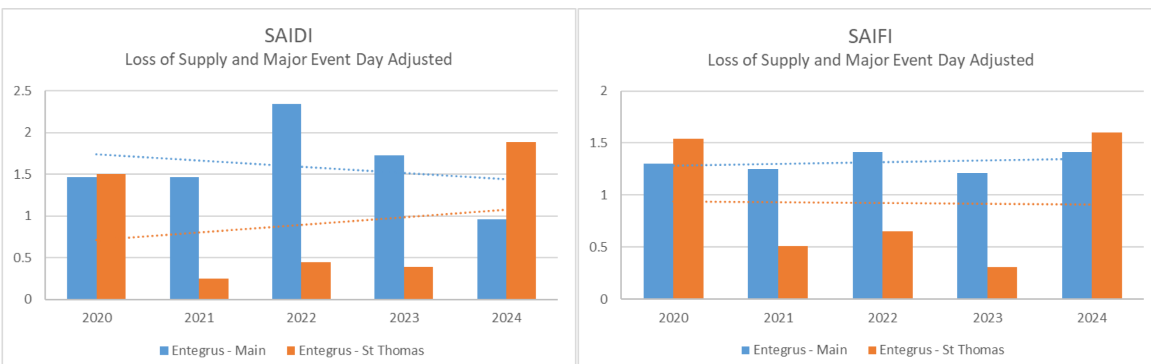
Similarly, EPI's SAIFI target was not achieved in 2020, 2021, 2022, and 2024, with performance driven by the same underlying factors—aging infrastructure and substantial adverse weather events below the MED threshold. In addition, in 2024 EPI experienced a significant amount of SAIFI contribution from foreign interference (See Table 3-26). While EPI has increased its implementation of smart grid technology and conducted asset renewal (including targeted pole remediation) to mitigate both outage frequency and duration, the benefits of these investments are gradual, and results can continue to fluctuate in response to storm frequency and severity.

Since the merger of Legacy EPI and STEI in 2018, EPI has served two separate Rate Zones (EPI-Main and EPI-St. Thomas) corresponding to pre-amalgamation service areas, with reliability statistics tracked internally by rate zone. It is important to note that EPI's reliability targets were established in the 2021 DSP, based on the unified post-merger service territory.

The figure below graphically reproduces a portion of the above table, specifically the LOS and MED adjusted SAIDI and SAIFI metrics for EPI-Main and EPI-St. Thomas.

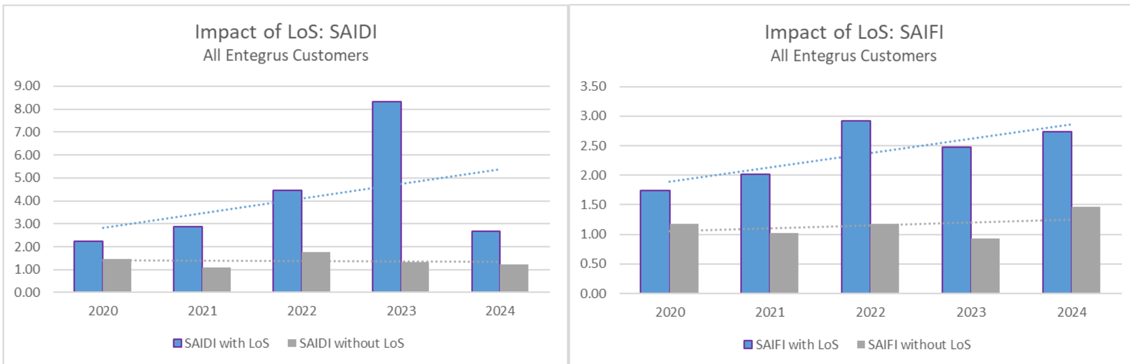
The EPI-St. Thomas rate zone has continued to enjoy better average reliability and lower SAIDI/SAIFI compared to the EPI-Main rate zone. This stability can be attributed to St. Thomas' proximity to its sole TS and the associated distribution system being contained within the geographic boundaries of a single community. SAIFI has held stable in the community, but increased customers on each feeder due to growth in the community has put pressure on SAIDI. Historically, the community has been fed from four feeders from a single transmission station and, as such, there are large numbers of customers on each feeder. High peak loading creates congestion in the community during outages. This can cause infrequent, but material outages as evidenced in 2020 and 2024. The installation of the M13 feeder will reduce congestion on the system during peak loading times, while simultaneously diluting the number of customers per feeder, thus easing EPI's ability to restore power and reduce the scope of these impactful outages. Additionally, automated feeder segmentation is scheduled for installation over the forecast period, which should reduce these large outages going forward. In comparison, the EPI-Main rate zone includes 16 separate communities, which are supplied from a variety of different TSs. Improvement focuses in EPI-Main include asset renewal and an investment focus on worst performing feeders (see Section 5.1.2.2) and implementation of additional system segmentation and distribution automation (see Section 5.1.2.3.1).

Figure 9: SAIDI and SAIFI Results by Rate Zone



Scorecard reporting excludes both LOS-related outages and MEDs. Due to EPI's highly embedded supply arrangement, EPI recognizes that exclusions have meaningful impacts on customer experience. Customer experience is better reflected in the upward trend of Total SAIDI and Total SAIFI trends in Figure 10, which includes impacts to customers associated with LOS and MEDs.

Figure 10: Total and Adjusted SAIDI and SAIFI Results for Entire EPI Customer Base

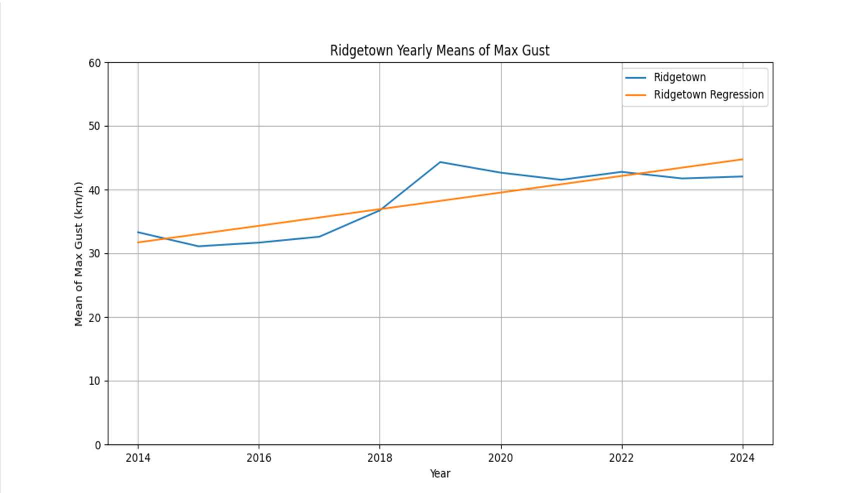


As discussed in Section 3.3.2.5, EPI has experienced more frequent and longer-duration outages due to equipment failure since 2020. Recognizing that its oldest and poorest quality assets are within the low-voltage networks, EPI has historically focused its System Renewal investments on Voltage Conversion projects and will continue to do so. The 2024 ACA (Attachment B) highlights the poor quality and increased age of substation assets, particularly switches, and the associated risks of substation failure. This underscores the importance of investing in Voltage Conversion projects and subsequent substation decommissioning. Additional details on asset renewal prioritization can be found in Section 4.3, with Voltage Conversion described at Section 5.1.2.2.1 and plans detailed in Attachment J.

As conversion work progresses, the 27.6 kV network has expanded both in customer count and physical area. To maintain reliability and mitigate the impact of single failures, EPI has invested in improving circuit segmentation within its larger urban centres where there is sufficient system grid diversity to accommodate this strategy. This segmentation limits the number of customers affected by a single failure and reduces overall outage time by allowing crews to patrol smaller areas to identify outage causes. More information on planned smart grid investments can be found in Section 5.1.3.3.

EPI has also observed an increase in the frequency and severity of weather events within its service territory, further emphasizing the need to replace deteriorated, at-risk infrastructure. Figure 11 illustrates a clear increase in nearby wind speeds over the last decade, which is expected to place growing pressure on asset renewal and vegetation management efforts.

Figure 11: Average Daily Maximum Wind Speeds



Source: Environment Canada

3.3.2.4 Major Event Days

From the inception of MEDs reporting in 2016 through 2022, EPI used OEB reporting option (c), the Fixed Percentage Approach, to define MED thresholds. This approach set a threshold at 10% of customers affected. Using this methodology, one MED was reported in 2018 and another MED was reported in 2022.

<u>2021 DSP Historical Period</u>

The 2018 MED occurred from April 14, 2018 to April 16, 2018 due to an ice storm affecting Chatham, Strathroy, and St. Thomas. At its peak, approximately 12,597 (22%) of EPI customers were without electricity, with a total of 16,190 customers (28%) affected during the event. The storm caused outages due to tree contact and equipment damage.

<u>2026 DSP Historical Period</u>

On June 1, 2022, a severe thunderstorm led to another MED, primarily impacting Chatham and Wallaceburg. At its peak, 15,069 customers (24%) were without electricity. Additional outages in Merlin, Newbury, Mount Brydges, and Strathroy affected 2,835 more customers.

Following the OEB's March 2, 2023, letter, which discontinued the Fixed Percentage Approach, EPI adopted the IEEE Standard 1366. This standard was retroactively applied from January 1, 2023, to March 1, 2023, to ensure consistency. For 2023 and 2024, a MED was defined as an event with at least 13,291 and 13,933 customer outage hours, respectively. Using this methodology, four MEDs were reported in 2023.

In 2023, the EPI service territory experienced significant periods of severe weather, culminating in four MEDs:

- From February 22, 2023 to February 23, 2023, freezing rain impacted Blenheim, Bothwell, Chatham, Erieau, Merlin, Ridgetown, Tilbury, Wallaceburg, and Wheatley. This event resulted in 13,395 customers without electricity (42,838 customer outage hours) and an additional 5,534 customers affected by Loss of Supply (16,155 customer outage hours).

- On February 27, 2023, freezing rain again affected Chatham and Blenheim. This event impacted 4,560 customers (16,993 customer outage hours) and an additional 318 customers in Merlin due to Loss of Supply (730 customer outage hours).

- From July 26, 2023 to 27, 2023, severe lightning accompanied by a windstorm affected Chatham, Ridgetown, Strathroy, and Wallaceburg. This event resulted in 2,262 customers without electricity (13,440 customer outage hours) and an additional 757 customers in Dutton due to Loss of Supply (13,463 customer outage hours).

- On August 24, 2023, severe thunderstorms and high winds, impacted 20,755 customers in Bothwell, Chatham, and Tilbury (285,241 customer outage hours). An additional 2,000 customers in Wheatley and Erieau were affected by Loss of Supply (298,685 customer outage hours).

In 2024, EPI experienced one MED. On September 11, 2024, at 1:13 am, a motor vehicle hit and broke a Hydro One pole in St. Thomas which was joint use with the EPI circuit. This event impacted 5,390 customers in St. Thomas (15,496 customer outage hours).

3.3.2.5 Historical Outage Data by Cause Code

Consistent with the filing requirements, the following tables show the components of SAIDI and SAIFI on a combined basis broken down by the number of interruptions by cause code, the number of customer interruptions by cause code, and the number of customer hours of interruption by cause code.

Table 3-25: Number of Interruptions by Cause Code (Excluding MEDs)

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Outages	Percent Share
1	Unknown/Other	25	11	11	20	24	91	4%
2	Scheduled	62	199	199	210	237	907	38%
3	Loss of Supply	37	54	73	62	83	309	13%
4	Tree Contacts	42	33	19	12	9	115	5%
5	Lightning	14	8	8	7	6	43	2%
6	Defective Equipment	120	93	94	95	101	503	21%
7	Adverse Weather	6	7	16	29	4	62	3%
8	Adverse Environment	2	1	9	0	0	12	1%
9	Human Element	3	6	2	5	3	19	1%

10	Foreign Interference	48	63	58	47	86	302	13%
11	**Total**	**359**	**475**	**489**	**487**	**553**	**2363**	**100%**

EPI understands that the outage occurrences metric above does not account for the impact of outages as represented by Customer Interruptions and Customer Hours Interrupted (see tables below). The customer impact of outages depends to some extent on the historical configuration of the system (e.g. availability of redundancies), the geographical distance from an outage site to the nearest EPI operational centre, and a degree of randomness.

Table 3-26: Number of Customer Interruptions by Cause Code (Excluding MEDs)

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Customers	Percent Share
1	Unknown/Other	8,644	3,679	3,166	1,038	6,950	23,477	3%
2	Scheduled	2,955	7,930	5,374	8,320	4,577	29,156	4%
3	Loss of Supply	34,429	61,203	93,814	53,943	74,907	318,296	47%
4	Tree Contacts	10,788	11,989	6,805	4,086	9,746	43,414	6%
5	Lightning	12,513	3,530	6,536	4,035	977	27,591	4%
6	Defective Equipment	33,222	14,547	28,254	27,602	28,154	131,779	19%
7	Adverse Weather	220	5,563	9,199	2,386	234	17,602	3%
8	Adverse Environment	21	7	3,824	0	0	3,852	1%
9	Human Element	5	11,379	740	4,096	5,125	21,345	3%
10	Foreign Interference	3,372	4,457	9,726	7,428	37,875	62,858	9%
11	**Total**	**106,169**	**124,284**	**167,438**	**112,934**	**168,545**	**679,370**	**100%**

Table 3-27: Number of Customer Hours of Interruption by Cause Code (Excluding MEDs)

Line No.	Cause Code	2020	2021	2022	2023	2024	Total Outages	Percent Share
1	Unknown/Other	7,293	1,252	256	1,016	3,424	13,241	2%
2	Scheduled	6,515	12,830	8,771	15,524	4,727	48,366	6%
3	Loss of Supply	45,627	109,725	105,305	71,261	75,637	407,555	49%
4	Tree Contacts	30,211	8,431	18,382	3,981	18,455	79,460	9%
5	Lightning	10,353	3,599	16,922	4,849	1,583	37,306	4%
6	Defective Equipment	30,041	19,583	25,578	38,362	29,980	143,545	17%
7	Adverse Weather	989	8,246	25,763	4,063	298	39,358	5%
8	Adverse Environment	133	1	4,710	-	-	4,843	1%
9	Human Element	9	3,752	437	265	639	5,102	1%
10	Foreign Interference	3,909	9,496	9,297	15,059	20,235	57,997	7%
11	**Total**	**135,078**	**176,914**	**215,420**	**154,382**	**154,979**	**836,774**	**100%**

While LOS events are beyond EPI's control, their impact on customers can be significant. Table 3-26 and Table 3-27 show that LOS outages have historically accounted for an average of 47% of all Customer Interruptions and 49% of all Customer Hours of Interruption experienced by EPI customers.

Recognizing the substantial impact of these outages to customers, EPI and the upstream supplier have collaborated over the Historical Period to mitigate the effects of LOS through Smart Grid Technology projects in Tilbury, Wallaceburg, Blenheim, Chatham, and more recently, Ridgetown. These projects utilize automated smart switches to transfer customers to an available supply when a LOS event occurs. Table 3-28 below summarizes the significant impact these projects have had in reducing outage hours experienced by customers.

Table 3-28: Reliability Impact Summary of Smart Grid Investments

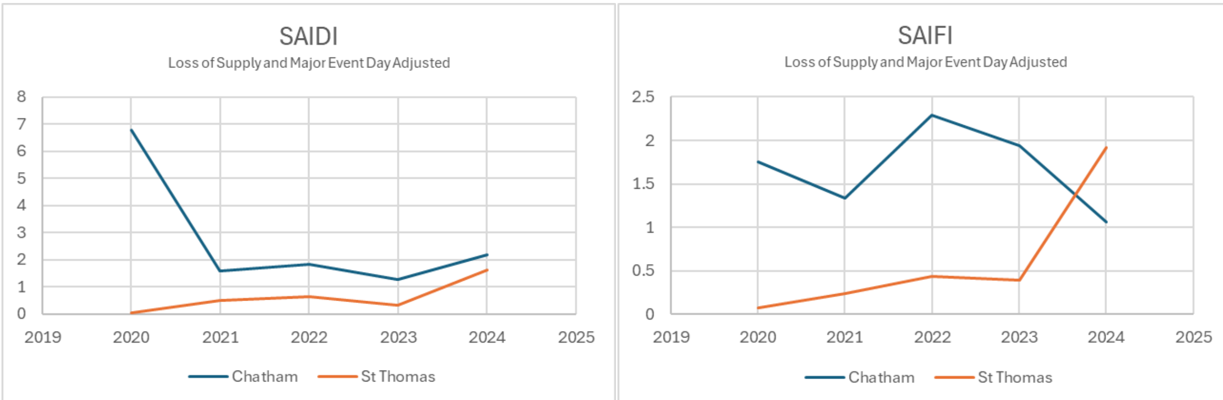
Line No.	Community	Smart Switch Team	Commissioning Year	Lifetime Customer Outage Hours Avoided	Percent of Outage Hours Avoided
1	**Tilbury**	One Reclosers & Two SCADA-Operated Switches	2017	10,092	7%
2	**Wallaceburg**	Four SCADA-Operated Switches (No Reclosing Functionality)	2018	39,182	27%
3	**Blenheim**	Two Reclosers & One SCADA-Operated Switch	2019	23,486	31%
4	**Chatham**	Nine SCADA-Operated Switches (No Reclosing Functionality)	2020, 2024, 2025	7,986	9%
5	**Ridgetown**	Three Reclosers	2021	43,775	51%

In total, the Smart Switch projects detailed above have reduced customer outage hours by 124,521 since 2017.

EPI continuously monitors SAIDI and SAIFI metrics across different regions to evaluate reliability performance and strategically guide Smart Grid investments. During the historical review period EPI's focus was on enhancing segmentation capabilities for large feeders in Chatham and St. Thomas. As outlined in the 2021 DSP filing, EPI committed to reassessing these investments in 2024 based on updated reliability data.

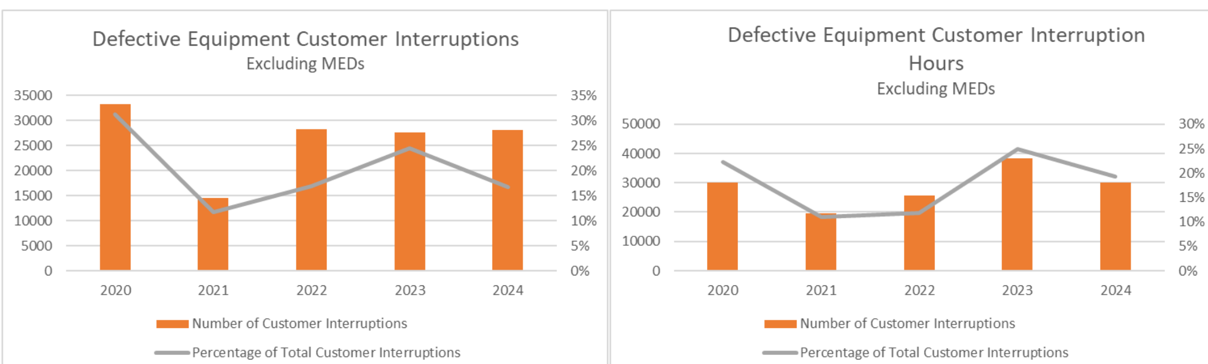
As illustrated in Figure 12, Chatham consistently demonstrated less favorable SAIDI and SAIFI performance prior to 2024, reinforcing the need for targeted investments to improve reliability in this region.

Figure 12: SAIDI and SAIFI Results by Town



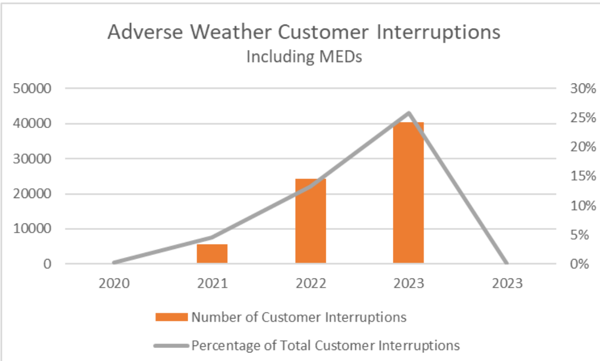
As detailed in Table 3-26 and illustrated in Figure 13, outages resulting from defective equipment are the second most impactful to EPI. This is a historically meaningful contribution to EPI's reliability and illustrates the need for EPI to continue to focus investments on System Renewal.

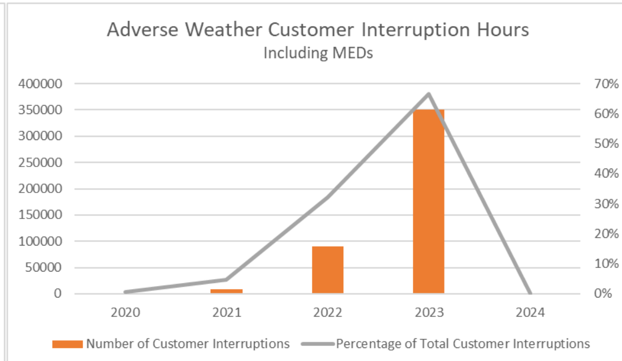
Figure 13: Defective Equipment Outages



As Figure 11 illustrates the increasing trend in wind, Figure 14 illustrates impact of adverse weather on EPI's reliability. For these Figures, weather related MEDs were included to highlight customer experience. The Adverse Weather Cause Code is composed of the following subcodes: Tree Contact due to Adverse Weather and Equipment Breakage due to Adverse Weather.

Figure 14: Adverse Weather Outages





3.3.3 Distributor Specific Reliability Targets (5.2.3.3)

EPI uses the fixed performance target set out in the OEB Scorecard for SAIDI and SAIFI based on its historical average performance, excluding LOS and MEDs. Through the December 2024 Customer Satisfaction survey completed by Concentrix (see Exhibit 1, Attachment 1-E), EPI received feedback that 96% of customers are satisfied with EPI's Reliability of Service. EPI has also received feedback through its Phase One and Phase Two Customer Engagement exercise that ensuring reliable electrical service is one of the top priorities for EPI's customers. See Exhibit 1, Section 1.7.3 for a summary of Customer Engagement results. Based on this feedback, EPI plans to make appropriate investments in order to maintain reliability performance.

4 ASSET MANAGEMENT PROCESS (5.3)

This section provides an overview of EPI's asset management process, a description of assets that make up EPI's system, and the tools and processes underlying the asset lifecycle optimization work. Overall, this section aims to articulate the main issues characterizing EPI's existing asset base and outline the framework of values, tools, and activities in place to maximize the value of both the existing plant and new capital additions.

4.1 PLANNING PROCESS (5.3.1)

4.1.1 Overview of Planning Process

EPI's Asset Management ("AM") Objectives articulate the key forms of value that it expects to provide to its customers, staff and shareholders by managing and evolving its asset base over time. The objectives serve as a critical tool for EPI asset managers, enabling them to assess how investment decisions or changes to asset management processes align with and support the utility's broader corporate mission and strategic goals.

The foundation of EPI's AM objectives lies in its overarching Mission, Vision and Core Values framework (Exhibit 1, Section 1.3) and DSP objectives (Section 2.1). This alignment ensures that the principles guiding asset management decisions are consistent with EPI's vision for delivering safe, reliable, and sustainable electricity services. By linking AM objectives to strategic goals, EPI fosters a cohesive and value-driven approach to utility management.

To support effective decision-making, EPI has assigned specific weightings to each of its six AM objectives, determined by corporate leadership. These weightings help asset managers navigate trade-offs between competing priorities, ensuring balanced consideration of operational, financial, and stakeholder impacts. While the weighting varies across individual objectives, no single objective is considered in isolation, to ensure comprehensive and balanced decision-making throughout the asset lifecycle optimization activities.

Since the submission of the 2021 DSP, EPI has introduced a new AM objective, "Grid Modernization," to address the growing need for investments that support the electrification of transportation and heating, and other emerging customer and policy-driven demands. This addition reflects EPI's proactive approach to meeting future system needs and ensuring that its infrastructure remains aligned with evolving industry trends and societal expectations.

Table 4-1 summarizes EPI's AM objectives, illustrating their connections to the utility's corporate values, DSP objectives, and key performance indicators. The relationship between EPI's DSP objectives and RRFE performance outcomes can be found in Table 3-5. The table also highlights how the assigned weightings inform prioritization of investment activities, providing a transparent framework for decision-making.

Table 4-1: EPI's Asset Management Objectives

AM Objectives	Articulation of Objectives	Relevant DSP Objectives	Related Performance Measures (see Section 3.3 except as noted)	Prioritization Weighting
Public/Employee Safety	Construct and operate the system in a manner that minimizes the probability and / or impact of injuries to staff, contractors and the public.	**Safety**	- Non-Occupational Serious Electrical Incidents - Lost Time Hours - Level of Compliance with O. Reg 22/04	5
Environment	Continuously explore and execute on ways to manage the impact of EPI's asset base and operating activities on the natural environment.	**Sustainability**	- Line Losses	4
Reliability	Deploy an optimal mix of System Renewal, System Service and O&M solutions to minimize the number and duration of power outages experienced by EPI customers, including those occurring due to loss of upstream supply.	**Sustainability**	- SAIDI - SAIFI - CAIDI - MAIFI - Worst Performing Feeder - Defective Equipment	3
Grid Modernization	Manage infrastructure to accommodate increasing load demands, to integrate DERs and to support electrification and customer growth. capacity for load customers and DER's.	**Customer Evolution**	- Number of Decommissioned Stations (see below)	3
Operational Efficiency	Continuously explore and execute on opportunities to reduce the labour-intensive components of EPI's capital and	**Prudent Investments**	- OEB Efficiency Assessment	2

AM Objectives	Articulation of Objectives	Relevant DSP Objectives	Related Performance Measures (see Section 3.3 except as noted)	Prioritization Weighting
	maintenance work through investments in new technology and managerial innovation.			
Cost Effectiveness	Deploy new capital in a manner that seeks to minimize asset lifecycle costs across all utility functions.	**Prudent Investments**	- Cost Effectiveness	3

See Section 3.3 for details on performance measures tracked since the 2021-2025 DSP. In addition, please see below for the new Station Decommissioning metric added to this 2026-2030 DSP.

4.1.1.1 New 2026 DSP Metric – Substation Decommissioning

EPI is actively decommissioning outdated legacy voltage substations as part of its Voltage Conversion program, a central element of its System Renewal strategy. This work involves upgrading legacy low-voltage feeders to the modern 27.6 kV standard, eliminating the need for costly station rebuilds and addressing deteriorating infrastructure such as aging poles and transformers.

The Station Decommissioning metric, newly introduced in this 2026–2030 DSP, provides a tangible performance measure of progress within the Voltage Conversion program. This metric demonstrates how capital investments are achieving both system efficiency and modernization goals, and how they align with broader asset management and strategic objectives, such as Grid Modernization and Cost Effectiveness. Although not specifically earmarked as a metric in the 2021-2025 DSP, EPI was seeking to complete the decommissioning of 5 sub stations and reached this goal as shown below.

Table 4-2: Stations Decommissioned

Description	2021	2022	2023	2024
Number of Stations Decommissioned as a Results of Voltage Conversion	2	1	0	2

For the 2026-2030 DSP window, EPI will target the decommissioning of another 5 substations.

4.1.2 Summary of Changes to Asset Management Process since last DSP Filing (5.3.1a)

EPI has made advancements in its AM processes to enhance its decision-making framework, reliability tracking, and readiness for future system needs. These changes reflect the utility's commitment to continuous improvement and alignment with industry best practices.

Enhanced Data Collection and Assessment Methodology

As recommended in the 2021 Asset Condition Assessment, EPI has transitioned from single-parameter (age-based) to multi-parameter (condition-based) assessments for nearly all asset classes. This transition enables engineers to more effectively target capital programs.

EPI has also enhanced its internal analytics capabilities through the addition of a dedicated Data Scientist in 2025. This role supports ongoing improvements in data modeling, system assessment, and predictive analysis, with the flexibility to contribute across a range of asset management and planning initiatives.

Update to AM Objectives and Tools

Previously, Public Safety and Employee Safety were treated as separate categories. These have now been merged into a unified Safety Objective to streamline evaluations and eliminate overlap. This change ensures safety-centric projects are effectively highlighted while recognizing shared benefits for both employees and the public.

In addition, in response to the rising electrification demands since 2021, EPI has introduced Grid Modernization as a standalone AM Objective. This category emphasizes investments in infrastructure to support Distributed Energy Resources, Electric Vehicles, and other emerging technologies critical to electrification.

Advances in Reliability Analysis

Following the merger with STEI, EPI implemented more detailed sub-cause codes for tracking service interruptions. In 2021, these codes were aligned with the OEB standards ahead of amendments to the RRR filing requirements, demonstrating proactive engagement through the Reliability and Power Quality Review working group.

Since January 2023, EPI has participated in the OEB’s Distribution Supply Point Interruption Reporting Pilot, improving its ability to identify and address issues in embedded communities that are not captured by traditional metrics.

Lifecycle Cost Optimization

EPI has enhanced its lifecycle cost analysis processes by considering costs at both the individual asset level and the system level. Lifecycle costs are now evaluated not just on an asset level, but also on a circuit-by-circuit basis, accounting for critical and costly upstream assets such as substations. This analysis consistently validates the prioritization of voltage conversion and replacement in lower-voltage networks over equivalent-condition assets in the 27.6 kV network.

Integration of Non-Wires Alternatives

Since the last DSP submission, EPI has refined its integration of NWAs by establishing a detailed screening process aligned with OEB'S Benefit-Cost Analysis ("BCA") Framework that focuses on exploring cost-effective, non-traditional alternatives and their technical feasibility to address local distribution needs such as for capacity expansion to address growing load demand. This approach incorporates customer feedback, such as reluctance toward DR, to balance innovation with reliability and stakeholder needs.

Standardization of Design and Capacity Planning

To address anticipated long-term increases in residential customer demand due to DERs (including EVs and heat pump adoption), EPI has updated its engineering standards. The per-customer capacity allocation has been standardized to 6 kVA for residential customers, replacing the legacy range of 3–5 kVA. EPI has also adopted 100 kVA transformers as the standard for residential distribution, replacing the previous 50 kVA and 75 kVA standards. Transformer bases are now designed to accommodate larger 166 kVA units, providing flexibility to triple capacity in the future without additional civil costs. In addition, updated designs enable cost-effective bus-splitting, doubling transformation capacity per customer as load develops with minimal incremental cost.

These advancements in EPI's AM processes reflect a forward-thinking approach to addressing customer needs, optimizing system performance, and preparing for the future of electrification. By incorporating enhanced data methodologies, reliability tracking, lifecycle cost optimization, and standardized design practices, EPI continues to strengthen its commitment to delivering safe, reliable, and cost-effective electricity services.

Climate Resilience and System Hardening

Consistent with the Minister of Energy and Electrification's letter of direction dated Dec. 19, 2024, EPI seeks to consider environmental factors in developing its capital programs. Currently all capital program funding decisions are based on economic prudence. Where possible, detailed designs attempt to bring benefits for climate resilience and system hardening. Proposed investments in this DSP which are prudent and cost effective and also provide climate resilience and system hardening benefits include:

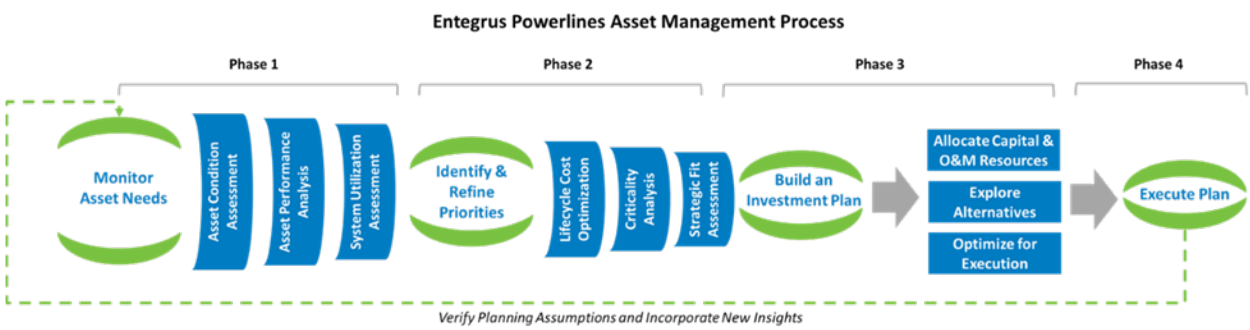
- Voltage Conversion to improve system resiliency and remove aged assets (Section 5.1.2.2, Appendix L "Voltage Conversion")
- Additional capacity and improved reliability for the city of St. Thomas by adding a new breaker (Section 3.2.6.2, Appendix L "Capacity Enhancements")
- New metering point to improve capacity and enable future investments in Mount Brydges (Section 5.1.2.3.3, Appendix L "Capacity Enhancements")
- Identification and proactive replacement of at-risk transformers using advanced analysis (Section 5.1.2.3.3, Appendix L "Capacity Enhancements")
- Improved Smart-metering communication resiliency (Section 5.1.2.2.4.1, Appendix L "Metering Renewal")
- Additional System segmentation and distribution automation (Section 5.1.2.3.1, Appendix L "System Modernization and Planning")

4.1.3 Process (5.3.1.1)

This section describes the nature and sequencing of tools and processes EPI uses to collect, analyze and operationalize information that informs its asset intervention decisions. See Section 4.3 for the discussion of specific policies and principles underlying the use of these tools and processes.

Figure 15 depicts the key functional elements of EPI's AM process. As the graphic indicates, the overall process entails a constant information feedback loop assessed and refined though dedicated tools and processes that enable EPI to allocate its capital and O&M resources. The sections that follow describe the fundamental features of every phase of the AM process and the analytical procedures and capabilities supporting them.

Figure 15: EPI Asset Management Process



4.1.3.1 Phase 1: Asset Needs Monitoring

The first phase of the AM Process attempts to capture the information on the current state of EPI's system and non-system (i.e. General Plant) assets, their continued ability to perform their intended functions, and available indicators of the upcoming requirements to expand, enhance or otherwise modify the utility's asset base. Phase 1 Consists of three elements:

- Asset Condition Assessment
- Asset Performance Analysis
- System Utilization Assessment

4.1.3.1.1 Asset Condition Assessment

EPI monitors condition of its major electrical system and general plant assets using multiple approaches, with each being applicable to a specific asset type or class. The overall purpose of asset condition assessment work is to capture and evaluate the evidence of certain physical or performance-based asset attributes that serve as leading indicators of impending asset End of Life ("EOL"). By assembling and analyzing objective evidence on the presence, prevalence or changes in rate of accumulation of these leading indicators of asset health, EPI gains a critical input that helps it plan the types, volumes, and timing of future asset intervention activities.

EPI performs several types of condition assessments that vary in their frequency, formality and types of equipment targeted:

- *Distribution Assets ACAs* – quantitative assessments of health of EPI's major electrical system assets using results of field inspection and testing activities. The results of the latest System Assets ACA performed by METSCO (Attachment B) are described in Section 4.2.2;
- *Metering Assets Verification Work* – regular cyclical or reactive activities in response to customer requests undertaken to verify the accuracy of EPI's revenue meters discussed in Section 5.1.2.2.4;
- *Fleet Assets Inspection Work* – evaluation of mechanical and structural integrity of EPI's vehicles and other rolling stock during regular or reactive maintenance discussed in Section 4.9;
- *Facilities Assets Inspection Work* – evaluation of structural integrity, observable wear and tear and other deficiencies of EPI's buildings and key building systems discussed in Section 4.8; and
- *IT Asset Lifecycle Evaluation* – assessment of whether and how the deployment of EPI's software and hardware assets aligns with the utility's IT AM strategy discussed in Section 4.7.

EPI stores all distribution asset condition data gathered during inspections and testing in its GIS Asset Registry, which enables efficient retrieval for comprehensive (system-wide) condition analysis work and/or project-specific analysis and visualization in the course of outage scheduling, trouble call response, or project design activities. EPI staff capture condition information associated with other types of assets in a variety of dedicated tracking and reporting tools.

4.1.3.1.2 Asset Performance Analysis

Supplementing ACA work insights in the effort to identify potential asset intervention priorities is the regular monitoring of asset performance. When analyzed systematically, changes in asset performance levels such as electrical system outages or general plant equipment malfunctions / deficiencies can provide important insights that help asset managers further refine their longer-term investment plans and/or undertake near-term intervention activities to proactively limit risk exposure.

EPI gathers system performance information through a variety of activities:

- *Reliability Monitoring:* EPI tracks the duration, frequency, and causes of electrical service interruptions experienced by its customers. Historically, EPI used the standard Canadian Electricity Association Cause Codes. After merging with STEI, EPI adopted more granular sub-cause codes. In 2021, EPI aligned these sub-codes with the OEB, ahead of the official amendments to the RRR filing requirements, as part of its participation in the Reliability and Power Quality Review working group. Since January 2023, EPI has also participated in the Distribution Supply Point Interruption Reporting cross-referencing pilot with other utilities, providing additional insights into issues affecting embedded communities that are not identified by other RRR reporting metrics. Section 4.1.2 discusses the improvements EPI has made to its reliability tracking capabilities since its previous DSP filing.
- *Power Quality Monitoring*: As described in Section 3.3.1.1.3, EPI has taken significant steps to investigate and resolve power quality concerns identified by its customers.

- *System Loss Monitoring*: EPI targets electrical loss reductions through its continued investments into voltage conversion projects across its service territory. While voltage conversion carries several benefits beyond loss reduction, EPI regularly reviews the extent to which its conversion activities help reduce system losses, and by extension, customer bills.
- *Environment, Health and Safety Performance Monitoring*: As noted in Table 4-1, Safety and Environment are among EPI's core AM Objectives. Accordingly, the utility diligently tracks and rectifies all instances of equipment-related environmental and safety incidents, near misses or risks identified during facilities inspection or line patrol activities.
- *Third-Party Feedback*: another important source of information on performance of its system is the input on performance of its assets EPI regularly receives from its customers, contractors, developers, neighbouring transmitters/distributors, municipalities, telecommunication companies and other stakeholders. This information typically results in identification and rectification of near-term concerns, but may also inform the development of longer-term plans where the evidence of persistent trends emerges.
- *General Plant Performance Monitoring*: EPI regularly reviews a variety of formal and informal operating metrics that track performance of its IT, Fleet, and Facilities assets. This includes investigations into the causes and impact of instances of IT systems downtime, cybersecurity events, and regular monitoring of sensor data embedded in fleet and facilities systems.

Together with asset condition monitoring and asset performance tracking, the data helps EPI gauge whether and to what extent its existing asset base is meeting the current needs of its customers. Then by extension identify the potential scope of candidate assets for future system intervention activities, to be further refined, prioritized, and adjusted through the remaining AM Process steps.

4.1.3.1.3 System Utilization Assessment

While the previous two steps inform EPI of the issues associated with its existing assets, the activities comprising System Utilization Assessment work use the available information to identify whether, how and when the existing asset base will require enhancement, expansion or other forms of modification driven by current or anticipated changes in their utilization. These activities include:

- *Administration of the Customer Connection Process*: EPI's Conditions of Service prescribe the steps that EPI regularly undertakes to facilitate requests from current and prospective customers to connect to its system and/or expand, relocate, or modify the existing connection facilities. Beyond informing its near-term system design and work execution plans, the outputs of customer connection planning also help EPI track the rates at which formal connection applications and informal inquiries across different asset classes materialize into actual customer additions. This analysis helps EPI calibrate its longer-term System Access requirements and provides an input into its load forecasting activities.
- *Load Forecasting Work*: EPI publishes five-year forecasts of station peak loads updating them as required by the regional planning processes, as system conditions change or other needs emerge. From time to time, and as required by the Regional Planning process

activities described in Section 3.2.6, EPI collaborates with Hydro One and/or the IESO to develop longer ten-year load forecasts for parts of its system involved in an active regional planning undertaking. EPI also conducts sensitivity analyses following the OEB's recommendations and guidelines as published in the "Load Forecast Guideline for Ontario" document, integrating all relevant sensitivity drivers specified in Section 6.3.1 of the OEB document.

- *Electrification Considerations*: As part of its load forecasting process, EPI has considered the potential impact of electrification, including the adoption of electric vehicles and heat pumps (see Section 4.4). EPI annually develops high and low sensitivity scenarios, in accordance with Section 6.3.2 of the OEB's "Load Forecast Guidelines for Ontario" document, to evaluate plan adaptability and establish future monitoring benchmarks. In April 2024, IRG conducted a Public Safety Awareness survey on behalf of EPI, which focused primarily on public safety (see Attachment L). As part of this survey, EPI included a set of questions related to the energy transition. The results showed only modest customer interest in EVs and heat pumps. Thereafter, Phase 1 customer engagement in the summer of 2024 corroborated these findings (see Section 3.2.1.2.2). Although these survey results suggested only modest customer load growth intent due to electrification at this time, it is crucial to recognize that a shift in customer behavior could trigger demand growth within this DSP window (although it is uncertain at this time). Additionally, there is the risk large connection requests (e.g. large EV charging parks or data centres) could consume available station capacity. Consequently, EPI remains vigilant and ready to adjust its forecasts and plans to accommodate any emerging trends or significant changes in load growth.
- *System Utilization Analysis*: in response to impending connection requirements by large load or generation customers and/or as a follow-up to recommendations of Regional Planning reports, EPI periodically analyzes the opportunities to accommodate new load and/or defer potential system capacity expansion work through load transfers on its distribution system. This work is undertaken in an integrated way with EPI's capital planning process and its capacity planning exercises.
- *General Plant Assets Utilization Analysis*: EPI staff responsible for management of the IT, Fleet and Facilities infrastructure periodically review the degree to which the existing systems and assets are being utilized, and whether any changes (upgrades, expansions, or decommissioning of redundancies) are warranted.

In summary, the first phase of EPI's AM Process aggregates the initial evidence on the total range of known and forecasted asset needs over the next five to ten years. At this stage of the process, the evidence exists in a relatively high-level form and is usually decentralized across the utility functions responsible for the specific types of assets, or operating functions that these assets support.

4.1.3.2 Phase 2: Identify and Refine Priorities

The second phase of EPI's AM process seeks to refine the initial aggregate list of potential asset needs by assessing their relative value propositions from the perspectives of lifecycle cost economics, risk reduction potential and alignment with EPI's strategic values. This phase consists of three elements:

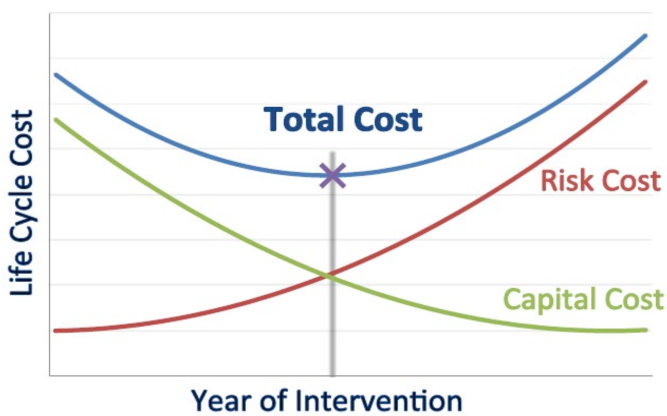
- Lifecycle Cost Optimization
- Criticality Analysis
- Strategic Fit Assessment

Importantly, while these three elements are presented in a sequential order, in many cases the analytical work underlying them occurs simultaneously and/or includes only some of the assessment components.

4.1.3.2.1 Lifecycle Cost Optimization

Management across departments seek to minimize the lifecycle costs of the assets in their care. Apart from cases where intervention cost and timing are dictated by external circumstances (e.g. volumes of new customer connections, revenue meter seal verification timelines, contributions to regional capacity projects, etc.), or reactive response to asset failures, EPI seeks to execute its asset intervention activities in alignment with lifecycle cost minimization principle described further below.

Figure 16: Asset Lifecycle Minimization Approach



The above Figure 16 illustrates three curves: the annualized *capital cost* of an existing asset represented by the light green curve, the annualized risk cost associated with the same asset shown in red, and the total lifecycle cost curve, which is the sum of the two, depicted in blue. As the utility and its customers derive value from an existing asset over time, its annualized capital cost typically declines. Concurrently, as the asset remains in service longer, the likelihood (probability) of failure or other types of malfunction increases. The product of this increasing failure *probability* and the potential economic *impact* of such failures - including direct costs to the utility for rectification and indirect costs to customers and society - represents the *risk cost* associated with the asset.

In addition to reactive expenditures for addressing in-service asset failures, the rising risk cost curve also reflects the higher maintenance costs often associated with aging or degraded assets. For electrical system assets, this could involve increased expenditures to source spare parts for outdated equipment or perform major transformer overhauls. For IT assets, it might include commissioning software patches or relying on reactive third-party support after regular vendor support has ended. In the case of Fleet or

Facilities assets, this could involve more frequent refurbishment or overhaul activities that extend the asset's lifecycle but only by a fraction of the economic life of a newly acquired asset.

Considering the combination of a declining annualized capital cost and an increasing annualized risk cost, the economically optimal time for asset replacement or any major intervention generally occurs where the two curves intersect. As illustrated in Figure 16, this intersection corresponds to the lowest point on the blue total lifecycle cost curve, marked by an "*x*".

For some asset classes where ongoing maintenance costs do not materially rise with asset condition and the overall increase in cost for reactive replacement is not unreasonable, the intersection between the annualized capital cost and annualized risk cost can shift to the point that reactive replacement can become the preferred asset management strategy, ensuring that maximum value has been extracted from each asset, at the cost of a high proportion of reactive work.

It is important to note that EPI applies this asset lifecycle cost management framework to guide decisions on the optimal volumes of replacement investments and to prioritize asset interventions relative to one another. However, this approach is not used to determine the precise timing of intervention for any specific asset, given the scale of its annual portfolio and the number of potential investment candidates.

4.1.3.2.2 Electrical System Plant Lifecycle Cost Analysis

For the 2026-2030 DSP planning process, EPI applied the asset lifecycle cost concept at multiple levels: individual assets, sub-systems, and system-wide considerations. At the sub-system level, this approach evaluates the risks and costs associated with replacing assets that serve an entire circuit, station, or region, factoring in the potential failure impacts of downstream and upstream infrastructure. For example, when assessing lifecycle costs on a circuit-by-circuit basis, EPI incorporates the risks and costs of critical upstream assets such as substations. This comprehensive evaluation consistently highlights the economic and operational benefits of prioritizing voltage conversion to 27.6 kV and replacing legacy circuit and station assets within the lower voltage networks, rather than pursuing like-for-like replacements of the legacy infrastructure. This strategy ensures a more reliable, efficient, cost-effective and forward-looking distribution system.

General Plant Lifecycle Cost Analysis

The lifecycle cost optimization analysis work for the IT, Fleet and Facilities assets is informed by externally validated empirical analysis or broader industry research performed and/or commissioned by subject matter experts. This work includes third-party expert assessments of the condition of buildings and core building systems, vendor-recommended replacement milestones for Fleet, Facilities systems and IT assets (e.g. mileage, cycles, total runtime, etc.), and other forms of research performed by relevant departments. In most cases, the outcomes of such research are articulated in the form of departmental asset management policies. See Section 4.7, 4.8 and 4.9 for more information regarding these policies and practices.

4.1.3.2.3 Criticality Analysis

EPI recognizes that the total volume of potential asset intervention needs present in any given year significantly exceeds the amount of operations and capital funding available to the utility. This reality brings about the need for management to consider trade-offs between different types, scopes, locations, and timing of investments. Inherent in any trade-off analysis is the consideration of the opportunity costs of any investment – that is not only the cost of projects being pursued, but also the risk cost inherent in the projects that could have been pursued for the available funds. One of the ways in which EPI undertakes this analysis is by considering the relative criticality of potential investments that would otherwise present similar value propositions based on the preceding steps in the AM Process. This analysis is holistic by design, encompassing EPI's entire distribution system, and the assets needed to support the business. By pursuing investments deemed to be more critical relative to other potential candidates, EPI seeks to reduce the aggregate risk inherent in its system's status quo. There are several ways in which EPI undertakes criticality-based prioritization:

- *Safety Related Criticality:* capital investments or operational activities targeting the reduction of public and/or safety risks are assigned the highest criticality across all asset classes and are usually executed without delay.
- *Compliance-based Criticality*: activities prescribed by law, industry codes or conditions of EPI's distribution license are considered more critical than activities where EPI has discretion over the scope and/or timing of work. For example, EPI allocates funding to the anticipated System Access investments without carrying out any prioritization activities relative to other types of investments, due to its obligations as a licensed Distributor. If annual System Access expenditure needs exceed the budgeted amounts, the utility re-allocates some of its funds budgeted for proactive System Renewal work to ensure compliance with the DSC and EPI's Conditions of Service.
- *Electrical Connectivity Criticality:* all else being equal, assets located higher upstream (closer to the circuit source) on feeders that lack interconnection points downstream are automatically assigned higher criticality in the asset lifecycle cost analysis. This is because an outage higher up the feeder would interrupt service for all customers downstream, while an outage on one of the radial branches downstream of a line protection fuse would leave fewer customers without power. EPI also considers projects which reduce risk associated with high criticality by segmenting circuits, such as recloser projects.
- *Equipment Type Criticality*: outages of different types of assets require varying levels of time and effort to address. For example, a catastrophic failure of a station transformer is considered more critical than that of a pole-top transformer in the lifecycle cost prioritization analysis. Additionally, spot replacements and addressing adjacent assets have proven valuable in certain cases, as they enhance infrastructure resiliency to adverse weather events. These proactive measures strengthen the system, enabling it to withstand extreme conditions and continue providing essential power delivery services to customers.
- *Customer Load Type Criticality*: EPI recognizes that different types of customers value the cost of power interruption in different ways. Consequently, a hypothetical mid-week outage that interrupts the production process of an industrial customer is inherently costlier than a

mid-week outage affecting a residential dwelling, making the equipment on a feeder supporting the industrial customer more critical than the equipment supporting the house. In a similar manner, the analysis assigns higher cost/criticality to potential outages affecting critical loads such as hospitals, first responder stations and water treatment facilities.

- *General Plant Criticality Assessments*: the criticality analysis of potential replacements, upgrades or refurbishments of EPI's IT, Fleet and Facilities assets generally follows the same principles as the work that considers electrical plant. The managers in charge of the individual General Plant portfolios consider various dimensions of impact that failures or malfunction of different systems, tools or equipment components can have on EPI's customers, staff and critical utility functions. The potential projects targeting the greatest reduction of anticipated risk costs (estimated by considering the probability and impact of events) are typically ranked higher.

4.1.3.2.4 Strategic Fit Assessment

The final dimension of prioritization work that supports EPI's asset intervention planning involves consideration of potential investments against the utility's AM Objectives described in Section 0. While most elements of the prioritization work described above are aligned with EPI's AM objectives, the specific priority scores attached to each individual objective enable planners to consider the relative trade-offs between the projects that otherwise appear to have similar value propositions or enable important exceptions to the courses of action recommended by other types of prioritization analysis.

The assessments described in previous steps primarily involve the application of economic principles and/or technical considerations. In contrast, this dimension of planning work enables the use of managerial judgment by subject matter experts in a structured manner that reflects the balance of strategic priorities set by corporate leadership including the consideration of customer needs and preferences. Considering the complexity characterizing electric utility planning and work execution, EPI believes that managerial flexibility is a critical success factor in effective service delivery. To this end, the relative weighting of core AM Objectives represents a high-level strategic reference tool that managers can rely on when necessary and beneficial while exercising discretionary judgment appropriate for their mandates.

4.1.3.3 Phase 3: Constructing the Investment Plan

The third phase of EPI's AM Process entails preparing annual Investment Plans using the insights collected through the analytical work described above and guidance from the executives and the Board of Directors.

The previous stages of the AM Process are largely concerned with *identifying potential asset intervention needs* that carry the highest value proposition relative to other potential ways of deploying EPI's resources. The Investment Planning Phase, on the other hand, is concerned with *identifying specific means* of addressing the utility's most pressing asset intervention needs within the financial, technical and human capital constraints characteristic of the utility. In other words, while the previous two phases are concerned with identifying potential candidate programs and projects, the third phase is focused on allocating the utility's resources among these programs and projects and ensuring that they are executed as efficiently as possible. From this practical perspective, the investment planning work is comprised of three core elements:

- Allocating Capital and OM&A Resources
- Exploring Alternatives
- Optimizing for Execution

These stages are described in more detail in Section 5.2.1 that describes the specifics of the capital budget process. The subsections below provide brief summaries of the underlying objectives and activities.

4.1.3.3.1 Allocating Capital and O&M Resources

This initial stage of investment planning is the point of intersection between EPI's technical AM work and its broader investment strategy. The trajectory of EPI's investment strategy is informed by several inputs, including:

- Macroeconomic outlooks for Canada, Ontario and the province's southwestern region;
- Government policy at the municipal, provincial and federal levels;
- The outcomes of regional planning work concerning EPI and its assets;
- Stakeholder guidance gathered through ongoing consultation;
- Capital needs outlooks developed through earlier phases of the AM Process;
- Load, generation, and customer growth forecasts;
- Commitments made by EPI in previous regulatory applications.

The investment strategy trajectory as articulated in the budget process acts as a constraint to balance OM&A spending and capital investment levels in the following year and for the four-year outlook period that follows. Top-level budgetary constraints are balanced against the sum of the individual departmental budgets assembled by individual managers based on the insights of their AM process and other relevant considerations. The task of the Investment Planning process is to allocate the available financial resources across the candidate activities (developed and budgeted for bottom-up) to ensure that the next year's budget and the four-year outlook reflect the key strategic objectives, conform to compliance obligations and address the emerging risks in an optimal way with consideration to affordability.

After applying top-level budget constraints to their departmental budgets, EPI's asset managers proceed to plan specific investment projects. In doing so, they rely on the outputs of the earlier analytical steps to identify the most pressing asset intervention needs for a given year and gradually translate them into time, location, and activity-specific projects and programs.

4.1.3.3.2 Exploring Alternatives

The process of exploring alternatives for addressing the most significant asset intervention needs involves multiple dimensions, specific to the type of assets being considered for intervention.

At a minimum, when assessing alternative ways of addressing certain asset intervention needs, EPI considers the alternative of not proceeding with an investment within a given planning year, which amounts to deferring the project by one year or more. When considering this form of an alternative, asset managers are expected to consider the balance of costs and benefits of delaying the work, such as increased risk of failure or malfunction, or an opportunity to complete other potential projects, respectively.

For projects which relate to grid optimization such as introduction of additional feeders ties, incremental load or generation connections, or voltage conversion work, EPI considers the impact of the work on the greater system (such as the impact of the new load location on voltage stability and feeder loading).

For some classes of projects, specifically for grid optimization and capacity related projects, EPI will evaluate Non-Wires Solutions ("NWSs"). This evaluation is aligned with the OEB's BCA Framework. This evaluation is primarily undertaken when addressing new capacity needs rather than asset life-cycling projects. Other alternatives that EPI planners consider depend on the type of asset undergoing intervention, the party performing the work, the length of completion, materiality of an underlying investment, and others. The NWS consideration process is described in more detail in Section 4.6.

Where relevant, EPI asset managers explore alternatives at two levels:

- Options among individual candidate projects – to explore the value of proceeding with a given project relative to other candidate projects; and
- Options within a single project – to explore alternative scopes, timelines or means of execution (as applicable) for completing the project.

While most of this analysis is done in the environment of engineering planning and design, field crews may undertake options analysis while executing the work, where unanticipated difficulties or opportunities to realize incremental value emerge while completing the work. EPI attempts to limit execution-level scope alternations by ensuring that the third stage of analysis includes a site visit by a member of the engineering team and follow-up conversations with the crew leaders (where beneficial).

The outcome of this planning stage is the allocation of available departmental resources among specific programs and projects, and selection of preferred means of executing specific projects where alternatives may be available.

4.1.3.3.3 Optimizing for Execution

This step entails the preparatory activities that define the details of specific work execution activities. For the different types of work, these may involve several analytical and logistical steps, including:

- Detailed technical design and resource needs estimation;
- Scheduling and coordination with all relevant stakeholders;
- Procurement of necessary materials and/or services;
- Preparation and staging of work sites;
- Preparation of necessary project management materials.

While the preparatory activities will vary depending on the type of investment, the overall goal of this step is to ensure that projects are executed with maximum efficiency, precision, commitment to safety, and in accordance with the expected outcomes.

4.1.3.4 Phase 4: Executing the Plan

The final component of EPI's AM Process is the actual execution of capital and O&M activities comprising the Investment Plan. The key priorities at this stage are safety and execution efficiency, which are largely a function of the accuracy and precision of the planning and preparatory work, the training of EPI's crews and/or other individuals executing the work and the types of tools, equipment and other implements available to undertake the work.

EPI's approach to executing the Plan leverages a combination of in-house expertise and specialized external resources to maximize efficiency and cost-effectiveness. EPI primarily relies on its skilled internal workforce for construction activities, ensuring high levels of quality and consistency in execution. At the same time, contractors are engaged to manage peak workloads and tasks requiring specialized equipment or expertise – such as directional drilling or concrete pouring for underground cable renewal. This approach allows EPI to efficiently address fluctuating workloads while avoiding the costs of maintaining highly specialized capabilities in-house. EPI allocates approximately $1M annually for contracted services. Specialty contractors are engaged for activities such as directional drilling or concrete pouring for underground cable renewal, where maintaining internal resources would not be economical.

The utility's extensive service territory, spanning both Northeastern and Southwestern zones, introduces logistical challenges. To address these, EPI organizes its operations through operational centers located in Chatham and St. Thomas, as well as an equipment storage facility located in Strathroy. These locations are strategically positioned to minimize driving times, reduce operational costs, and improve outage response efficiency.

Table 4-3 outlines the communities served by each operating center as of September 2024. EPI periodically revisits this allocation to consider alignment with shifting system risks and operational priorities.

Table 4-3: EPI Communities by Operating Centre

Community	Southwest Operating Centre (Chatham)	Northeast Operating Centre (St. Thomas)
Blenheim	✓	
Bothwell	✓	
Chatham	✓	
Dresden	✓	
Dutton		✓
Erieau	✓	
Merlin	✓	
Mount Brydges		✓
Newbury		✓
Parkhill		✓
Ridgetown	✓	
St. Thomas		✓
Strathroy		✓
Thamesville	✓	
Tilbury	✓	
Wallaceburg	✓	
Wheatley	✓	

The successful execution of construction activities depends on resource management, particularly given the constraints posed by funding allocations, workforce availability, and geographical considerations. Key elements of this approach include:

- Regional resource allocation: Construction resources are balanced between zones, ensuring efficient deployment of crews and addressing areas of greatest system risk.
- Integration of risk-based prioritization: Projects are scheduled based on risk assessments, including asset condition, reliability performance, and safety considerations. This ensures that limited resources are directed toward the most critical needs.
- Synergies with previous work: Where feasible, planned projects are sequenced to build on the work completed in prior years, such as voltage conversion efforts targeting the decommissioning of aging substations.

EPI's execution strategy aligns with its broader goals of operational efficiency and cost-effectiveness. The integration of in-house and external resources reduces bottlenecks during peak demand periods while ensuring cost control for specialized tasks. Furthermore, regionalizing construction and outage response activities improves service delivery and enhances customer satisfaction by reducing response times.

By strategically deploying resources and leveraging past project data, EPI ensures that its capital plan remains adaptable to evolving risks and opportunities.

4.1.4 Data

EPI uses a variety of data sources to assist in the selection of projects and the development of a comprehensive investment plan. An essential component of this plan involves the timing of these specific projects to ensure optimal pacing of investment and asset replacement levels. The key sources of data used to inform the decisions regarding project selection and timing are further described below.

Distribution Asset Condition:

EPI maintains a record of each individual asset, including data such as age, location, make, model, material, and ratings. Where an inspection record has been completed for that asset, the inspection is linked to the asset and is available for review. EPI currently performs a 1/3 inspection of its system annually. This work involves visual inspection of the assets by a qualified power line maintainer, infra-red inspection of station and lines equipment, and drill testing on a sample of its poles. These records are stored in the GIS system.

Asset Location:

Asset location provides insight into the condition of surrounding assets to enable efficient renewal projects to be developed. These records are stored in the GIS system.

Asset Connectivity:

Understanding how assets exist in the greater system topology and what the impact of failure of that asset may be (e.g. a pole at the beginning of a feeder supplying several thousand customers vs. a pole with an identical condition and rating which serves only a handful of customers; a pole where an alternate path exists vs. a single path; serving primarily residential customers vs. public and emergency service facilities) allows EPI to better prioritize asset renewals. This information is stored in the GIS System.

Outage and Reliability Statistics:

EPI maintains detailed records of all outages impacting our distribution system including cause, duration, customer count, circuits impacted, specific customers impacted as well as a geographic representation of the outage. These are used to develop reliability centric SQI's (such as SAIDI/SAIFI and worst performing feeder). These are stored in a dedicated database.

Historical Failure Rates of Critical Assets:

EPI tracks distribution asset failures, including the type, age, and any additional inspection details. This failure information is used to help inform the risk of deferring capital work. This tracking started in recently and a large corpus of data is not yet available, limiting the weight that can be placed on the data set until more can be collected.

Substation Testing and Maintenance Reports:

EPI performs full electrical property tests on its substations as part of its three-year maintenance cycle. In addition to these tests, EPI performs annual oil analysis to monitor the condition of its station transformers. Visual inspections are performed monthly on all substations, allowing for the rapid identification of emergent issues, or damage from vandalism. EPI relies on this information to drive maintenance programs, identify opportunities for life extension projects, and to prioritize low voltage conversion work at the community level.

Building and Fleet Assessments:

The condition of fleet assets is tracked through common metrics like mileage, annual maintenance records, and expenditures, which are regularly reviewed. Visual building inspections are undertaken monthly. Contracts are in place for maintenance of some building systems (such as HVAC) and written recommendations are provided when repair or replacement is needed. Regular informal communication with these contractors provides ongoing feedback about the condition of the building systems even when no immediate action is required. An external comprehensive building condition assessment is undertaken for EPI's major structures ever 5 years. The current reports are available as Attachment H and Attachment I.

These reports are used to ensure that the timing of investments avoids failures which would result in additional remediation costs and workplace inefficiencies (e.g. due to insufficient rolling stock, or temporary unsuitability of a facility).

Customer Engagement:

EPI considers feedback from ongoing customer consultation and engagement activities, as well as Application-specific customer engagement. Customer consultation and engagement is discussed in detail in Section 3.2.1.

Pacing of Investments:

As described in Section 5.2.1, the senior leadership team reviews budget plans to confirm alignment with corporate objectives and considers the timing or pacing of certain projects. Once finalized, the capital expenditure plan is submitted to the Board of Directors for review and approval.

4.2 Overview of Assets Managed (5.3.2)

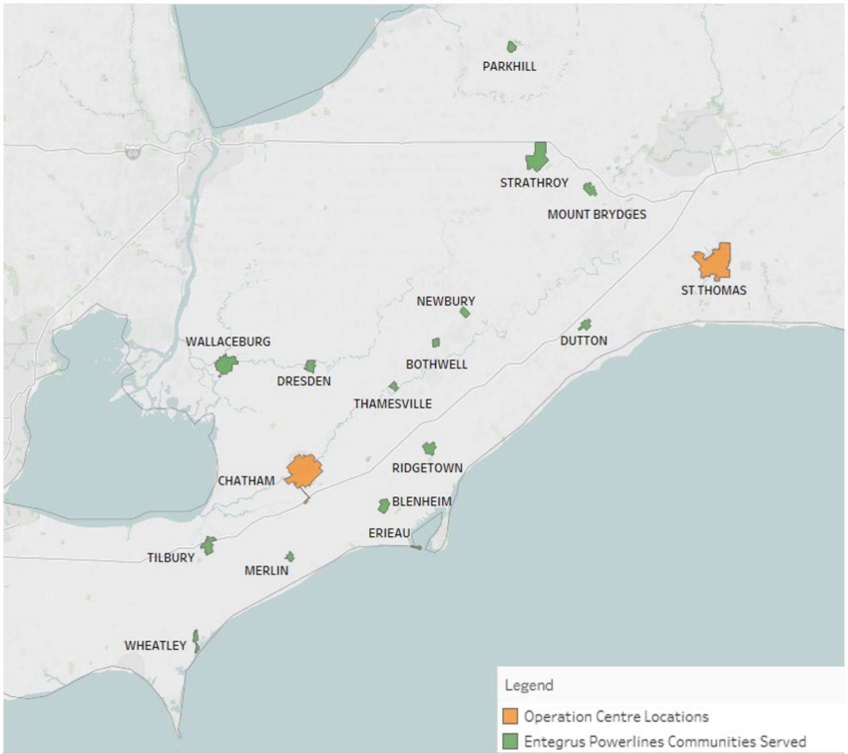
The information in this section contextualizes EPI's asset management work by describing the current state of EPI's power system, including its geographical location, electrical configuration, and the state of its major asset classes.

4.2.1 Description of the Service Area (5.3.2a)

EPI delivers electricity across 134 km² of urban service area, made up of 17 separate communities. Table 3-1 illustrates the number of customers in each community. The 17 communities EPI serves are spread across an area of more than 5,000 km², interspersed with predominantly rural areas serviced by Hydro One Dx. While some parts of the EPI system connect directly to a Hydro One Transmission Station (i.e.

Chatham. St. Thomas, Wallaceburg, and Strathroy), most communities are embedded within Hydro One's distribution system.

Figure 17: EPI Service Area Map as of 2024



EPI communities are urban areas of various sizes, including a variety of cities and towns. Being a product of multiple past utility amalgamations, the service territory contains multiple types and configurations of legacy electrical equipment. Consolidating equipment and configuration standards over time is a major dimension of EPI's ongoing System Renewal work.

Agriculture, automotive and service industries are among the largest employers in the area. As noted throughout this document, load growth has notably increased over the 2021-2025 Historical Period, with the most active growth segment across both predecessor utilities being the residential customers. This growth is discussed in detail in Section 4.4. Given the recent growth in St. Thomas and the existing need for additional capacity, EPI is currently working with Hydro One in 2025 to construct a new breaker and feeders emanating from the St. Thomas Edgeware TS. See Section 3.2.6.2 for discussion of the drivers underlying this planned investment.

EPI is not anticipating material growth in this 2026-2030 DSP period. With the exception of the projects previously identified, EPI anticipates adequate capacity for the forecast period. Given EPI's proximity to the Leamington area, which has experienced rapid and significant demand growth from commercial greenhouse proponents, as well as its proximity to large automotive battery projects in the Windsor and St. Thomas regions, it is anticipated that a number of locations will require capacity beyond the current forecast period. These future loads, combined with other potential requests to connect industrial customers, may push load growth beyond the forecasted values, which currently only include firm commitments and existing customers.

EPI's service area is characterized by a moderate humid continental climate. The climate is similar to that of Strasbourg France and the lower Great Lakes portion of the Midwestern United States. The region has warm humid summers and cold, usually moist winters. Extreme heat and cold usually occur for short periods. When compared with the rest of Canada (excluding the coastal areas), the climate is relatively temperate. In the fall and winter, the delayed cooling of the nearby Great Lakes moderates the temperatures – an effect that is reversed in the spring and summer when the afternoon warming is tempered. Annual rainfall ranges from 75-110 cm and is generally distributed throughout the year with a usual summer peak. Depending on location relative to the Great Lakes, parts of the region receive between 100-200+cm of snowfall. The area is prone to tornadoes and freezing rain and has the highest concentration of lighting flashes than anywhere else in Canada.

4.2.2 Asset Information (5.3.2b)

EPI's overall system consists of 17 geographically dispersed and electrically independent municipal power grids operating downstream of Hydro One's transmission system and/or Hydro One Dx distribution stations and connected by way of 36 supply points. Of the 36 supply points, 30 are operating at 27.6 kV (13 EPI-owned and 17 embedded), with the remaining six embedded connections operating at a lower 8.32 kV voltage.

EPI operates overhead and underground line assets supported by 16 transformer substations that stepdown power from 27.6 kV to 8.32 kV, 4.16 kV or 2.4 kV delta. As discussed throughout this DSP, EPI is in the process of converting its system to a single standard 27.6 kV primary voltage, which will eliminate the need for substations and the associated capital and OM&A expenditures. Among these substations, all have been in service for decades, with the oldest, MP Sub 4 in Strathroy, commissioned in 1955, underscoring the aging nature of this infrastructure.

A key facet of EPI's asset management strategy is to complete area voltage conversion activities in a manner that not only allows for the retirement of these aging station assets before costly replacements become necessary but also prioritizes the replacement of the oldest and most deteriorated assets. Since its 2021 DSP filing, EPI successfully decommissioned five of EPI's Substations, demonstrating significant progress in its voltage conversion efforts. These investments have reduced the total number of substations owned and operated by EPI to 16, further streamlining operations and supporting the transition to a standardized 27.6kV system.

The number of feeders EPI operates by voltage level is shown below. Each circuit is generally a mix of overhead and underground assets, serving a variety of customer types.

Table 4-4: Circuits by Voltage

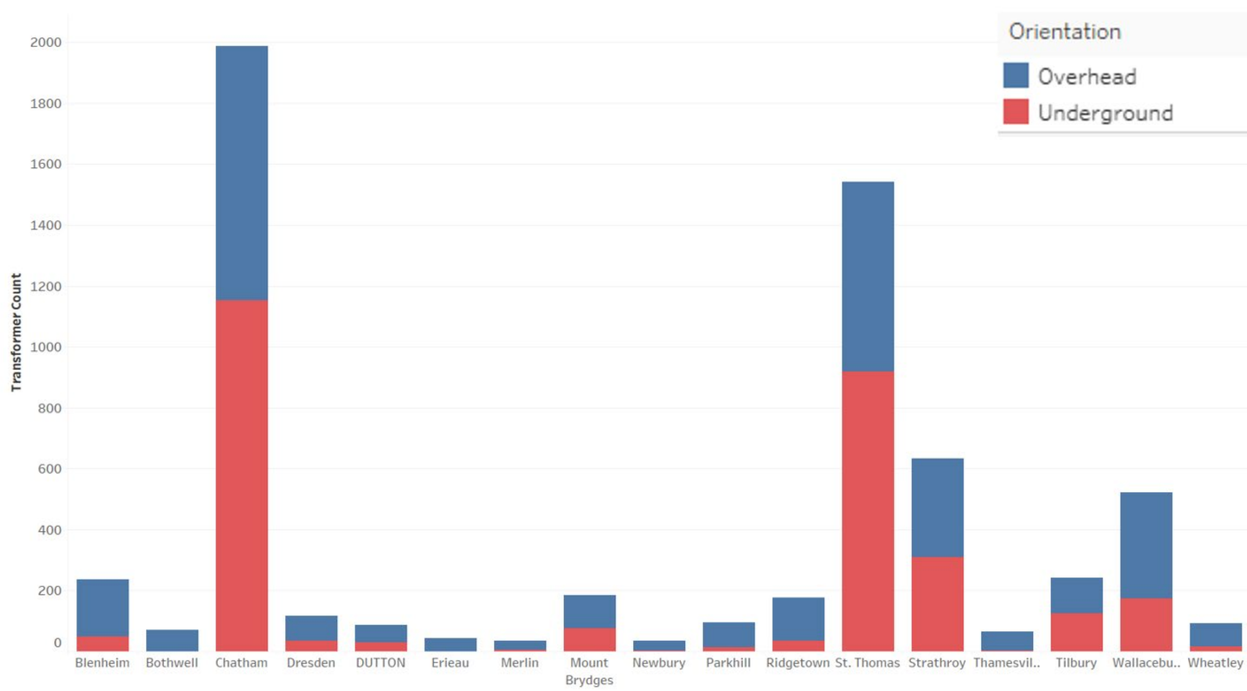
Voltages	Number of Feeders
2.4 kV Delta	4
27.6/16.0 kV	28

4.16/2.4 kV	23
8.32/4.8 kV	8
Grand Total	**63**

Substation design varies significantly, ranging from simple fuse-protected stepdown transformers with a single feeder tap to more sophisticated configurations featuring advanced protection functions and SCADA capabilities. EPI serves load from 16 municipal stations, which each contain a single power transformer. The average size of the station transformers is 4.1 MVA, with sizes ranging from 2.0 MVA to 7.5 MVA.

Figure 18 below shows the distribution of over 6,000 transformers by subtype (overhead vs. underground) currently in service across all EPI-served communities. The figure highlights the significant concentration of the customer base in Chatham, St. Thomas, and Strathroy, where most of EPI's underground infrastructure is also located. In contrast, most customers in the remaining communities served by EPI receive power through overhead lines, reflecting the differing infrastructure needs across the service territory.

Figure 18: Transformer Count by Community



In total, EPI operates 63 feeders at voltages between 27.6 kV and 2.4 kV. Table 4-5 breaks down the length of circuits by voltage and type of service to further contextualize the system configuration.

Table 4-5: Length of Overhead and Underground Circuits

Type of Service	Voltages	Total Length (Circuit km)
Overhead -Single Phase	16 kV, 4.8 kV, 2.4 kV	167.9 km
Overhead – Three Phase	27.6 kV, 4.16 kV, 8.32 kV	413.5 km
Underground -Single Phase	16 kV, 4.8 kV, 2.4 kV	359.2 km
Underground – Three Phase	27.6 kV, 4.16 kV, 8.32 kV	56.3 km

EPI owns distribution system equipment that falls into the following major asset classes described in Table 4-6 below.

Table 4-6: EPI Major Asset Class Counts

Major Category	Equipment Type / Asset Class	Unit Count
Substation Equipment	Power Transformers	16
	Circuit Breakers	13
	Switchgear	38
	Batteries	4
Overhead Infrastructure	Wood Poles	20,188
	Concrete Poles	21
	Steel Poles	454
	Overhead Conductor	581 km
	Overhead Transformers	3210
	Overhead Switches	728
Underground Infrastructure	Underground Cables	415 km
	Pad-Mounted Transformers	2643
	Submersible Transformers	161

Two distinct features of EPI's technical configuration that impact its costs and operational performance are the dispersed nature of its service territory and its location downstream of the upstream supplier's assets. Between the urban centers served by EPI, there are significant stretches of Hydro One Dx rural territory interspersed. This means that communities not co-located with a transmission station are often served by long radial feeders with the portion outside EPI's territory owned and operated by Hydro One as the host utility.

Section 3.3.2.3 discusses customer reliability and shows how it is materially influenced by LOS interruptions, comparing the "all outage cause" reliability metrics with the "LOS adjusted" reliability metrics. The successful installation of distribution automation equipment, in collaboration with the upstream supplier, has improved all-cause customer reliability. So far, equipment has been installed in the communities of Tilbury, Ridgetown, Blenheim, Wallaceburg and Chatham. These installations have collectively avoided over 124,500 Customer Hours of Interruption since they began in 2017. EPI continues to install distribution automation equipment to address all-cause reliability in its system.

EPI engaged METSCO, a third-party engineering and analytics firm, to conduct an independent ACA of its major distribution equipment. METSCO had previously performed the utility's first formal ACA for the 2016 DSP and again for the 2021 DSP. The June 2024 ACA report is available in Attachment B.

4.2.2.1 Asset Condition Assessment Overview

For all asset classes that underwent assessment, METSCO used a single scale of asset health from Very Good to Very Poor. The numerical Health Index ("HI") corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage.

The Table below presents the HI ranges corresponding to each condition score, along with their general corresponding implications as to the follow-up actions required by the asset manager at EPI. The assessments were based on the most recent inspection and testing data available, which was 2023 information.

Table 4-7: METSCO's Health Index Framework

Health Index Score (%)	Condition	Description	Implications
85-100	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
70-85	Good	Deterioration of some components	Normal Maintenance
50-70	Fair	Widespread deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
30-50	Poor	Widespread, serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
0-30	Very Poor	Widespread, critical deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Utilities often collect different types of asset data, but the similar inspection policies of Legacy EPI and former STEI allowed METSCO to create consistent asset health scoring methods. Nonetheless, EPI acknowledges that data from two distinct electrical systems may not always align. To address this, EPI standardized its inspection rating criteria and, since the 2020 ACA, has implemented a unified digital inspection system across its entire service area, though some variations persist in historical records.

EPI has made significant improvements to its asset data management practices since the 2021 DSP. These focused efforts provided METSCO with consistent access to a broader range of asset condition data, particularly for station assets. Coupled with refinements to METSCO's asset health index formulations since the last ACA, the availability of additional data resulted in material improvements in the health index conditions for certain asset classes. This was most notable for poles, power transformers, and circuit breakers (See Attachment B, page 5).

The condition data records available for the ACA analysis of EPI's line facilities are more limited than those for station assets due to reliance on exception-based data collection methods for line inspections. Consequently, METSCO used asset age as a key data input when assessing the condition of overhead and underground line assets, as well as certain types of station assets.

Looking ahead, EPI will continue to refine its ACA methodology by standardizing and enhancing data inputs across all asset classes. Efforts will focus on closing existing data gaps for key assets and increasing the volume and quality of field-collected condition data where feasible. These initiatives will further strengthen the accuracy of future condition assessments and ensure that asset management decisions remain robust, data-driven, and aligned with system needs.

When assessing data availability to calculate HIs, METSCO used the Data Availability Index ("DAI") that measures the percentage of condition parameter data points available for an asset or asset class, weighted by each parameter's importance. A valid HI is calculated only if the DAI is at least 70% for distribution assets and 65% for station assets. Assets below this threshold were extrapolated based on the distribution of assets with a valid HI for larger asset classes. Compared to the 2020 ACA, the 2024 iteration shows significant improvements in data availability, with several new condition parameters added, enhancing the comprehensiveness of the analysis. Although new parameters temporarily reduce average DAIs due to the need for additional data collection, the parameter-level breakdown highlights EPI's progress in data improvement. Additional details on these methodological updates can be found in Attachment B, Section 3.4).

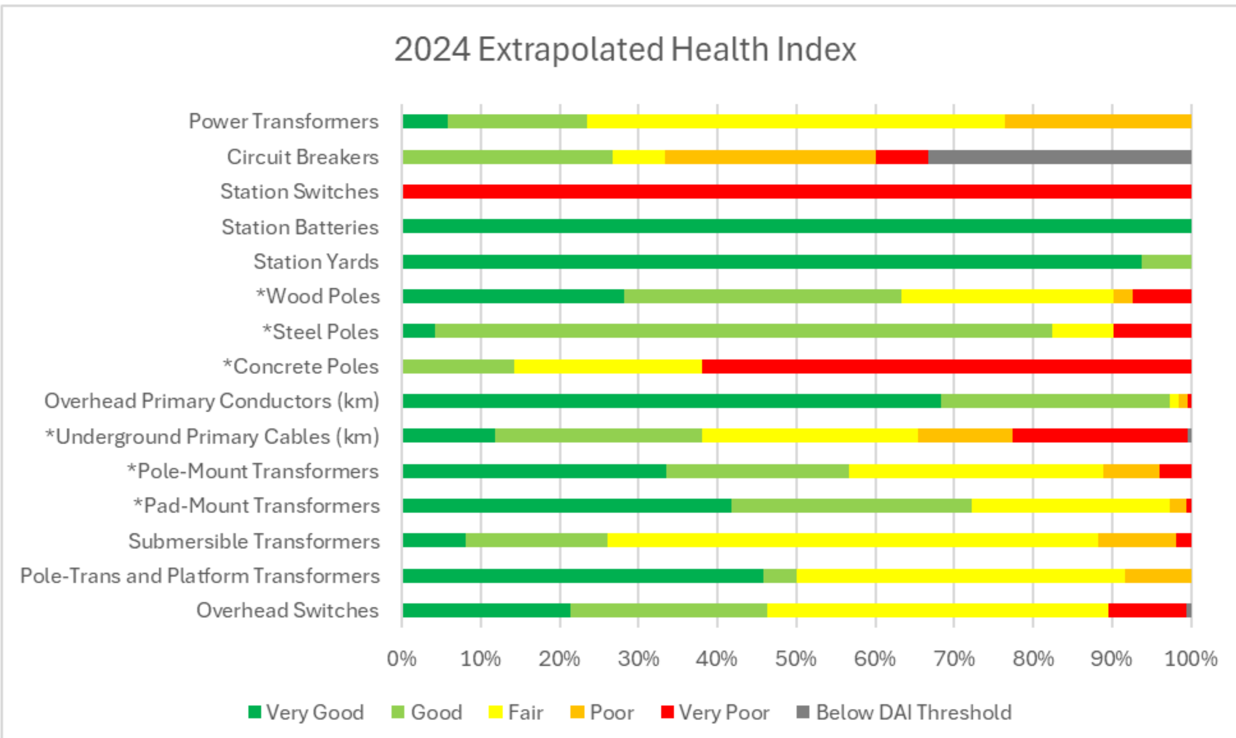
EPI's GIS serves not only as an asset register but also as a critical data source for engineering and operational tools. Recognizing the importance of high-quality data, EPI has an ongoing program to enhance the completeness and accuracy of GIS records. This program identifies gaps in information quality and seeks to address them through a combination of field inspections, acquisition of additional data sources (such as satellite imagery), and referencing historical paper records. Through this initiative, EPI expects to achieve continuous improvement in data completeness and quality over time.

The ACA results for major asset classes are outlined in the following sub-sections, with further details on the ACA methodology and additional asset classes provided in Attachment B.

The ACA analyzed 14 categories and subcategories of assets across EPI's installed asset base. It identified that assets in many key asset classes are in "Very Poor" condition, indicating these assets have reached the end of their useful life and are at an elevated risk of failure. The percentages of assets categorized as "Very Poor" include Circuit Breakers (7%), Station Switches (100%), Wooden Poles (7%), Steel Poles (10%), Concrete Poles (62%), Overhead Primary Conductors (0.5%), Pole Mount Transformers (4%), Pad Mount Transformers (1%), Submersible Transformers (2%), Overhead Switches (10%), and Underground Cables (22%). Figure 19 shows the ACA results for all asset classes.

See Section 4.2.2.2.3 below for additional information about Station Switch inspection, repair and mitigation.

Figure 19: ACA Summary



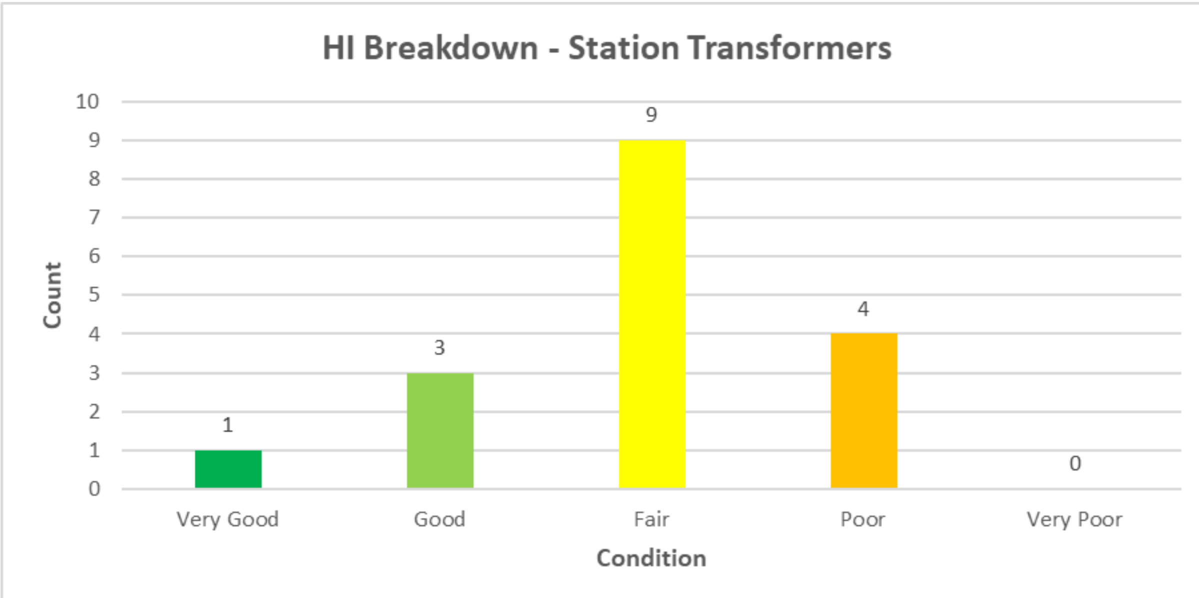
Lines marked with an asterisk have partial data availability, and results have been extrapolated to the full population

4.2.2.2 Station Assets ACA Results

4.2.2.2.1 Power Transformers

Figure 20 below presents the results of METSCO's power transformer condition analysis.

Figure 20: Power Transformer ACA Results



In the 2024 asset condition assessment, 20 condition parameters were used to formulate the HI criteria, an increase from the ten used in the previous assessment conducted for EPI. These parameters were added because of the availability of new data points provided by EPI:

- Service Age
- Bushing Condition
- Oil Level
- Oil Leak
- Explosion Vents
- Insulator Condition
- PT Condition
- CT Condition
- Arrestor Condition
- Fusing Condition
- Arcing Condition
- Peak Loading
- Dissolved Gas Analysis (DGA)
- Oil Quality
- Electrical Testing
- Turns Ratio Test

The majority of EPI's station power transformers are in Fair or worse condition, with the few classified as Good nearing the threshold for Fair status. The latest ACA results differ from the 2020 assessment, with some transformers reassessed to be in better condition due to the availability of a broader range of inspection data and condition parameters. While EPI has focused on maintaining its fleet of station transformers, the advanced average service age of these assets presents challenges, including difficulty or impossibility in sourcing spare parts, which increases both the risks and costs of maintenance compared to replacement.

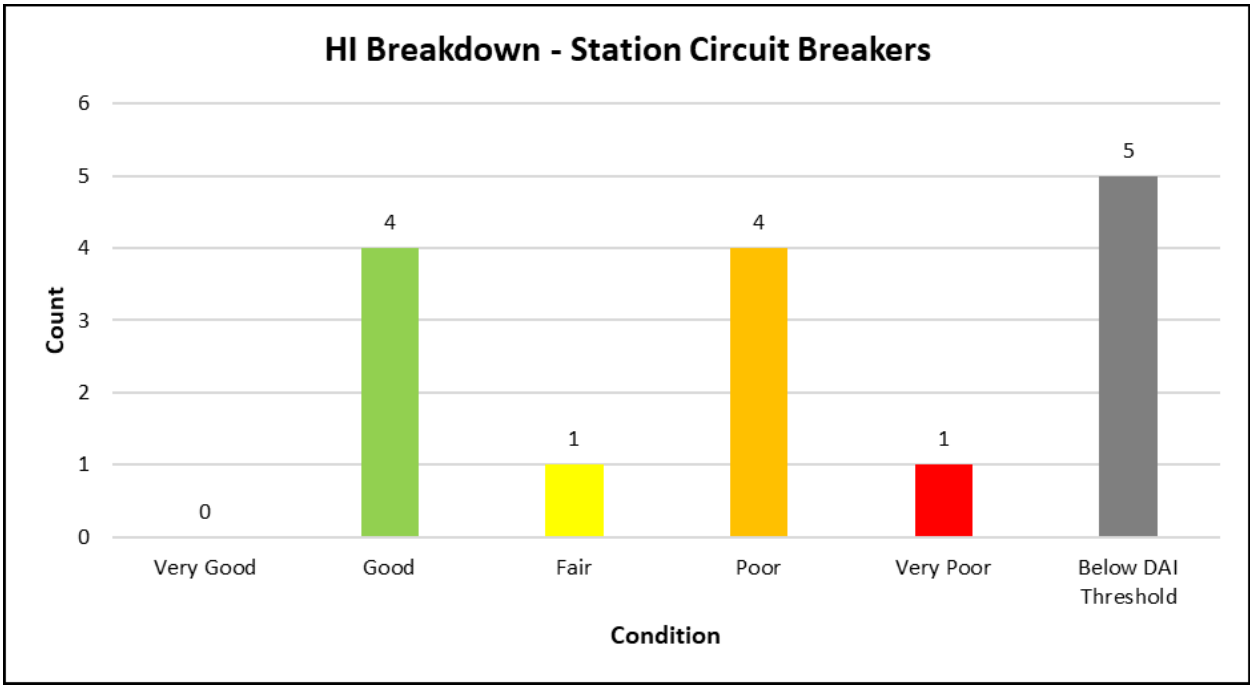
Based on this assessment, EPI does not anticipate station transformers to be a major investment driver over the Forecast Period. However, close attention should be given to units categorized as Fair and Poor. Preventative maintenance, such as transformer drying and other life extension activities, can be performed on Poor units during this period to mitigate risks and extend their operational lifespan.

In parallel, as discussed in Section 5.1.2.2.1, EPI is advancing its voltage conversion program to eliminate legacy 4 kV systems and enable the decommissioning of associated distribution stations, avoiding the significant capital costs of full station rebuilds. This strategic approach allows EPI to extend the operational life of aging station transformers only as necessary, until the feeders are fully converted to 27.6 kV and the stations along with the power transformer can be retired.

4.2.2.2.2 Circuit Breakers

Figure 21 below displays the Circuit Breaker HI results across all types of equipment.

Figure 21: Circuit Breaker ACA Results



Several enhancements have been made to the station circuit breaker HI algorithm since the previous iteration of the ACA. Data parameters have been consolidated into more relevant categories, and weights have been adjusted to more accurately reflect the condition of the assets.

EPI employs both oil and air-type circuit breakers. The evaluation criteria included the following:

- Control and Operating Mechanism
- Insulation Resistance Test
- Contact Resistance Test
- Arc Chute Condition (as applicable)

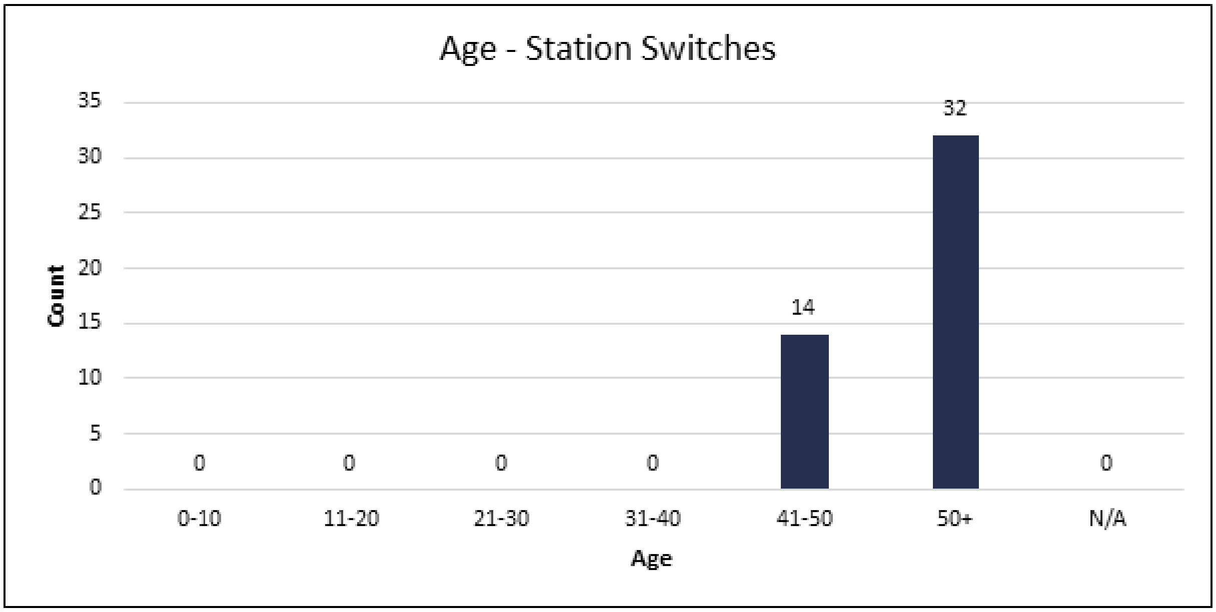
Similar to power transformers, the circuit breaker HI results have significantly changed since the last EPI ACA. These changes reflect both ongoing deterioration of the assets and updates to the assessment methodology. While one breaker was reassessed to a better condition, others were classified as being in Poor or Very Poor condition.

These results show that these assets will require additional monitoring and maintenance to mitigate failure risks and the associated customer impact. One-third of station breakers did not have enough data to complete a valid evaluation of their condition. However, as a result of ongoing voltage conversion plans and subsequent station decommissioning, two circuit breakers with insufficient data have been removed from service since this ACA was completed. The three remaining circuit breakers containing insufficient data will be decommissioned along with their substation by 2026. Looking ahead, stations with circuit breakers that are in Fair, Poor or Very Poor condition are scheduled for decommissioning within the forecast period.

4.2.2.2.3 Station Switches

Figure 22 below showcases the ACA results for EPI's switchgear units.

Figure 22: Switchgear ACA Results



There has been no change in the ACA methodology. Given the current approach to exception-based inspection recording, METSCO's assessment relied on asset age as a proxy for condition. To this end, the above graph presents the results by age cohorts rather than actual HI categories where inspection and/or testing parameters are available. With the age as the only condition parameter for HI, all station switches are in Very Poor condition. An error in the ages used in the 2020 ACA resulted in that document representing the assets as younger than their actual age. The current ACA has corrected this error. This accounts for the discrepancy between the 2024 and 2020 versions of the ACA, and the relative shift in asset condition between the reports. EPI has conducted monthly inspections of each substation (including switches) for many years. Moving forward, EPI will collect better data and additional documentation. Specifically, EPI will enhance its data collection processes to include the individual components of the visual inspections that are already occurring. These enhancements will make the asset index more reflective of true asset condition.

EPI continues monitoring its station assets through monthly station inspections and maintenance, which includes cleaning and repair of the switches. Inventory of parts is maintained, including like-for-like switches and switches that can be retrofitted. In addition, EPI owns and maintains two portable backup stations which can be put into service in the event of asset failure.

4.2.2.3 Line Assets ACA Results

4.2.2.3.1 Overhead Equipment

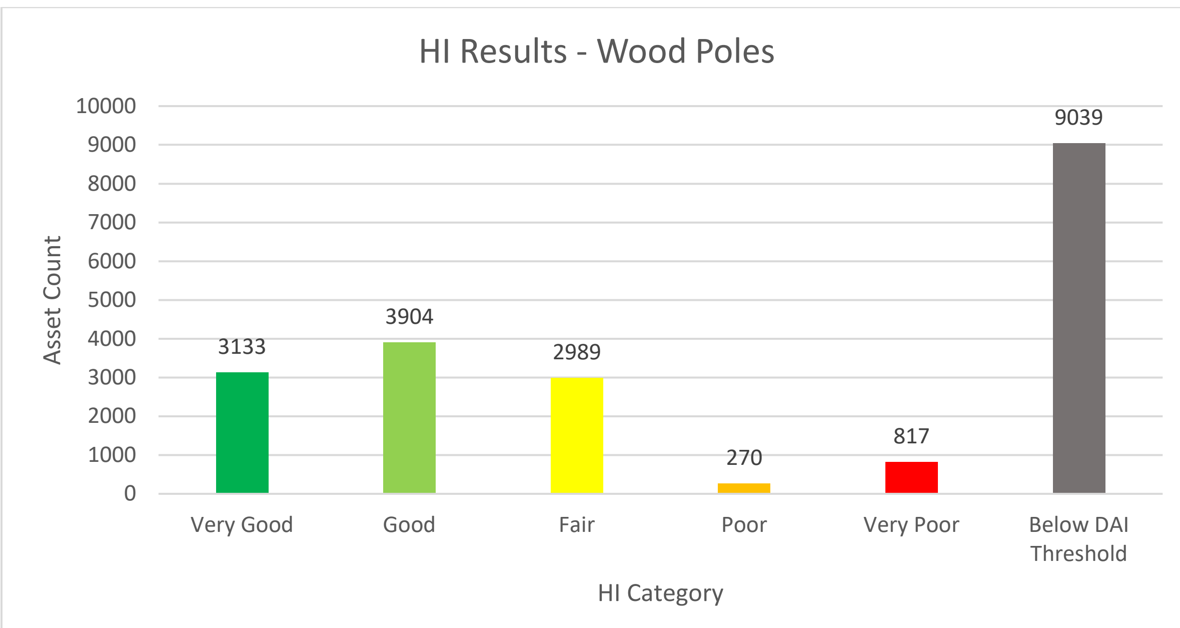
4.2.2.3.1.1 Distribution Poles

EPI's overhead system consists of approximately 21,000 poles, 95% of which are manufactured from wood, with the remainder made up of steel (2.2%) and concrete equipment units (0.1%).

Wood Poles

The previous ACA utilized only one criterion, "Service Age", to assess wood poles. The 2024 ACA introduces an additional parameter, "Remaining Strength", to the HI. During the Historical Period, EPI has collected this data point only for 55% of the poles, and as such, the remaining poles have data availability below the threshold.

Figure 23: Wood Poles ACA Results

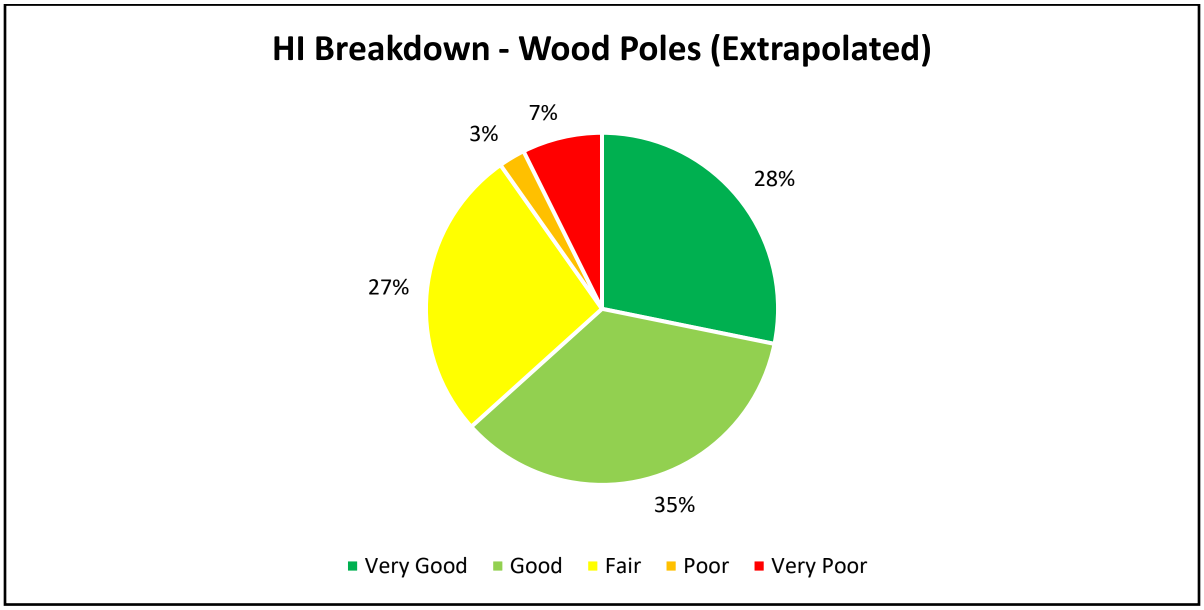


The analysis reveals a mixed condition profile for EPI's wood poles. While the number of poles in Poor and Very Poor condition has decreased since the 2020 ACA, the introduction of the "Remaining Strength" parameter has led to 9,039 poles being categorized as Below the DAI Threshold. This reclassification reflects a sizable proportion of poles for which complete condition data is unavailable under the updated methodology. Additionally, the number of poles in the Very Good, Good, and Fair categories has also declined, indicating shifts in data availability.

The 2024 ACA provides a breakdown of wood pole health indices when poles without the Remaining Strength parameter are extrapolated to the entire population. Figure 24 shows that 35% of poles are in

Fair or worse condition, with 10% classified as being in Poor or Very Poor condition. This highlights the need for continued focus on identifying and addressing aging and deteriorating assets.

Figure 24: HI Breakdown- Wood Poles (Extrapolated)



The identification of poles in Poor and Very Poor condition highlights the critical need to address aging and weakened infrastructure. These assets have been confirmed to exhibit reduced strength, compounded by their advanced age. Over the Forecast Period, EPI plans to continue drill testing on the remaining pole population.

To maintain the health of the overhead infrastructure, EPI will prioritize replacing wood poles as part of its proactive Voltage Conversion and Pole Replacement programs. Additionally, failed assets will be addressed reactively through emergency response efforts.

4.2.2.3.1.2 Steel and Concrete Poles

Figure 25 and Figure 26 below showcase the ACA results for EPI's steel and concrete poles. Both distributions are based on age data only.

Figure 25: Steel Poles ACA Results

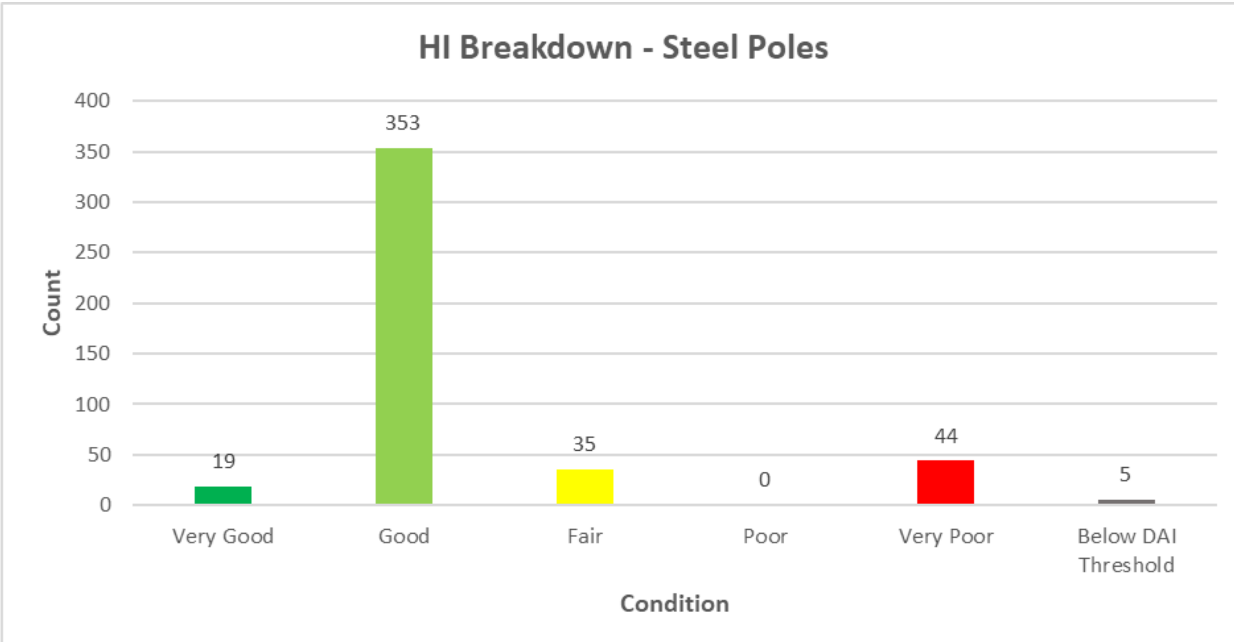
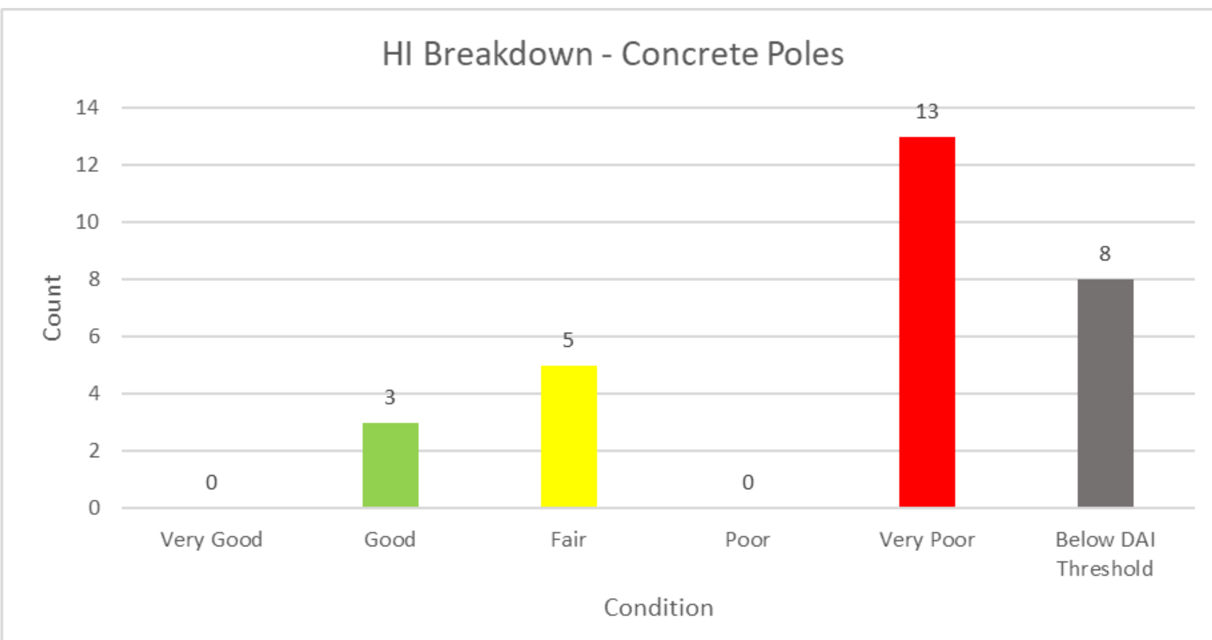


Figure 26: Concrete Poles ACA Results



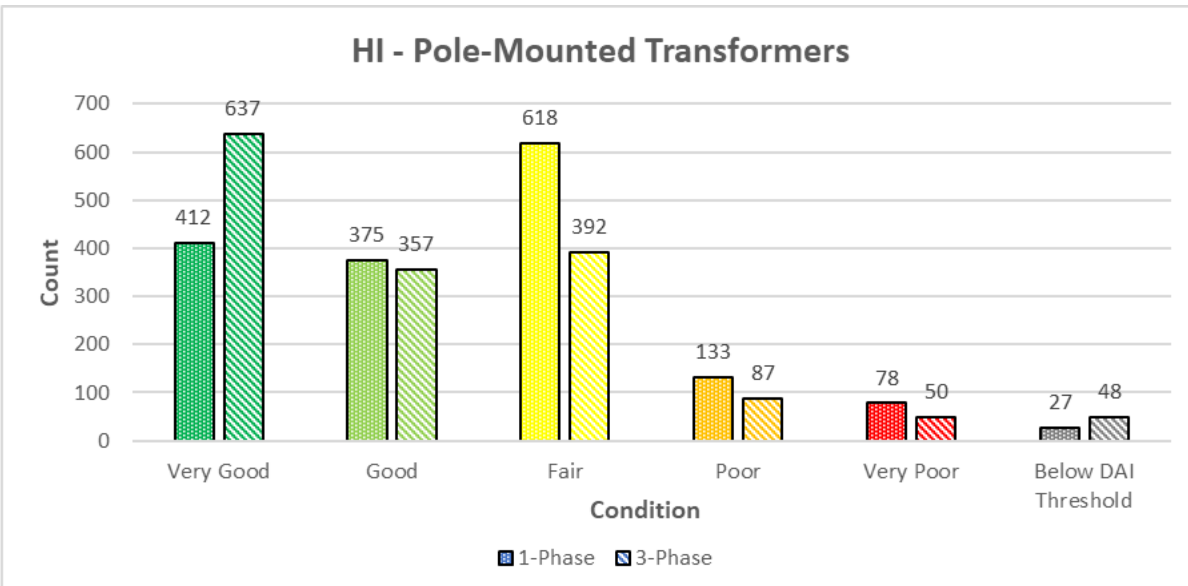
As a matter of standardization, EPI no longer installs new steel or concrete poles, unless specifically requested and paid for by a customer. Accordingly, all existing concrete and steel poles will be replaced by wood poles as they reach the end of their useful lives aside from the potential exceptions noted above.

Given the relatively small number of steel and concrete poles in its service territory, the decision to phase out these assets, and the additional complexity of determining remaining strength, EPI does not expect to dedicate any incremental resources to proactive condition data collection, beyond existing visual patrols and exception-based reporting.

4.2.2.3.1.3 Overhead Transformers

Figure 27 and Figure 28 show the ACA results for pole mount transformers and overhead primary conductor, respectively.

Figure 27: Pole Mount Transformers ACA Results



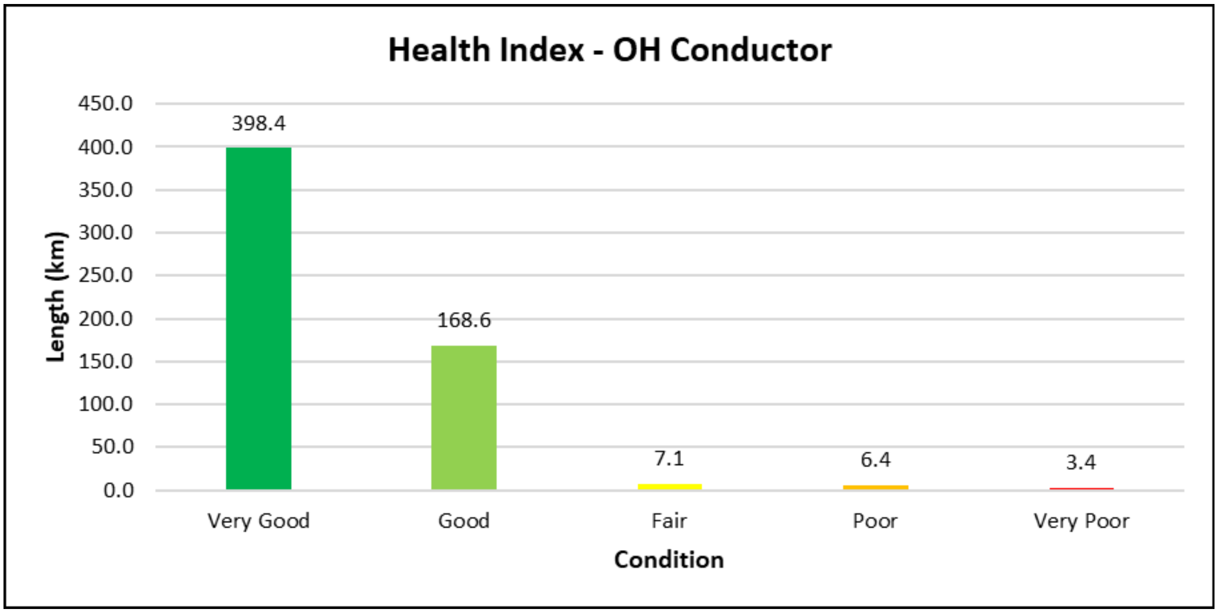
The 2024 ACA categorizes Pole-Mount Transformers into Single Phase (1 Phase) and Three Phase (3 Phase) groupings. Transformer results are based on a two-parameter assessment of service age and load history. EPI also provided infrared scan and visual inspection survey data. However, this data did not constitute a significant enough sample size to be factored into the HI.

Similar to poles, EPI plans to continue proactively replacing its overhead transformers as a part of the Voltage Conversions program, and reactively when patrol activities determine select equipment to have reached end of life or require capacity upgrades unrelated to asset renewal work.

As adoption of EV's and heat pumps begins to ramp up EPI has identified risk to its distribution transformers becoming overloaded. EPI has established a monitoring and forecasting program to identify individual assets most at risk. With customer support (See Exhibit 1, Attachment 1.7.3), most at risk assets will be proactively replaced.

4.2.2.3.1.4 Overhead Conductor

Figure 28: Overhead Primary Conductor ACA Results



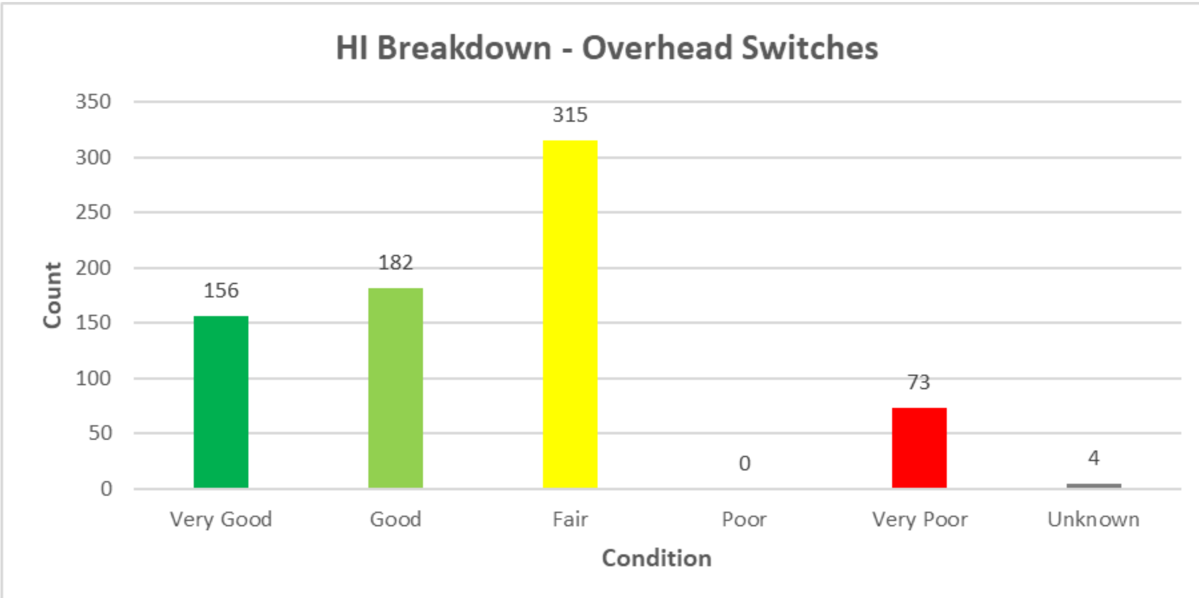
The 2024 ACA results for the primary conductors consist of a two-parameter assessment – namely age, and a gateway parameter known as Small Conductor Risk, which automatically de-rates certain types of outdated small-diameter copper conductor that has been largely phased out across North America.

As part of its ongoing Voltage Conversion program, EPI will continue to proactively replace overhead conductors and associated pole-top equipment, ensuring system reliability, alignment with current standards and higher capacity to accommodate increasing load due to future electrification activities.

4.2.2.3.1.5 Overhead Switches

Figure 29 below showcases the results of the age-based assessment for EPI's overhead switches.

Figure 29: Overhead Switches ACA Results



Results from the 2024 ACA show a range of improvements in EPI's portfolio of Overhead Switches. Specifically, 201 switches evaluated as Poor in the 2021 ACA have been either decommissioned, rehabilitated, or improved. Despite these improvements, the number of switches evaluated as Fair or worse condition (only based on age data) indicates a need for follow-up inspection work.

4.2.2.3.2 Underground Equipment

4.2.2.3.2.1 Pad-Mounted and Submersible Transformers

Figure 30 and Figure 31 display the ACA results for the population of EPI's pad-mounted and submersible transformer units supporting the underground services in the larger communities of Chatham, St. Thomas, and Strathroy. Both sets of results entail two-parameter assessments made up of the units' age and load history.

Figure 30: Pad Mount Transformer ACA Results

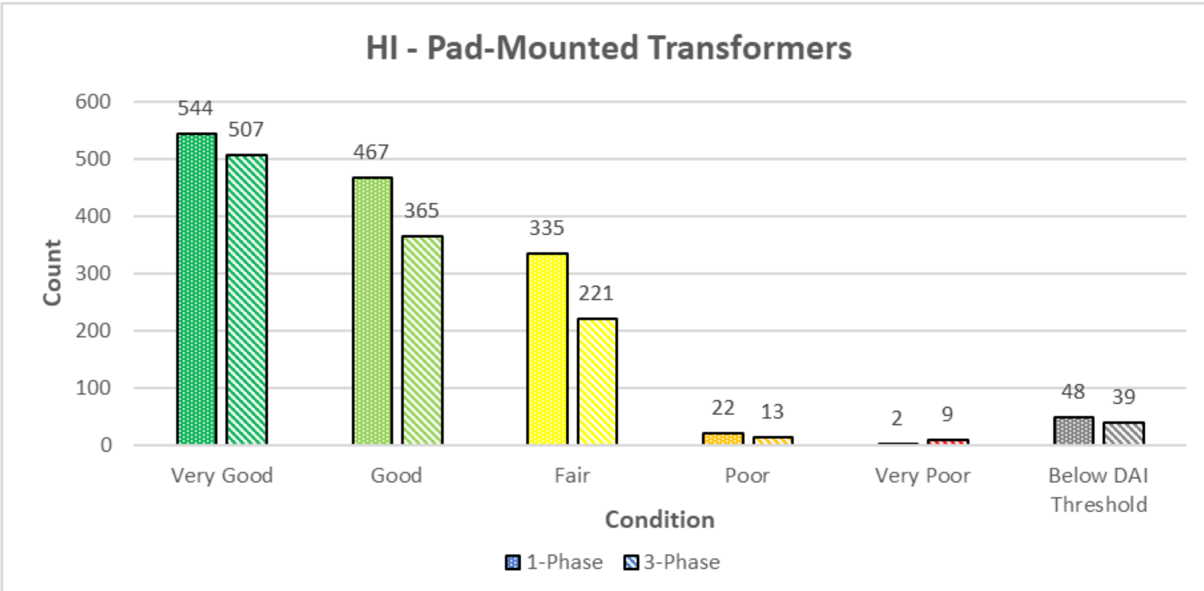
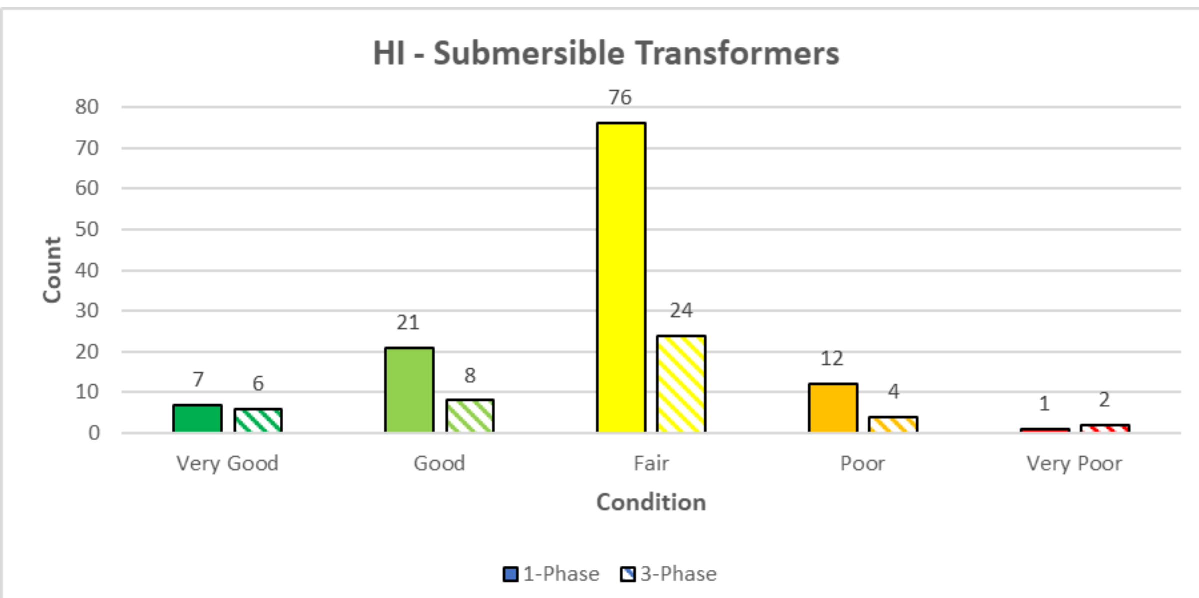


Figure 31: Submersible Transformer ACA Results



As with the overhead plant, EPI's current visual inspection protocols for pad-mounted transformers prescribe exception-based reporting, where crews generate inspection records only for those units where they find deficiencies that warrant near-term follow-up.

The condition of EPI's fleet of pad-mount transformers has shown significant improvement compared to the 2020 ACA. As of 2024, the population of pad-mount transformers has grown by 12%, with 73% of EPI's pad-mounted assets now in Good or Very Good condition. Despite this progress, follow-up and replacement activities will address the remaining 27% of assets in Fair or worse condition, consistent with the Lifecycle Management policies discussed in Section 4.3.

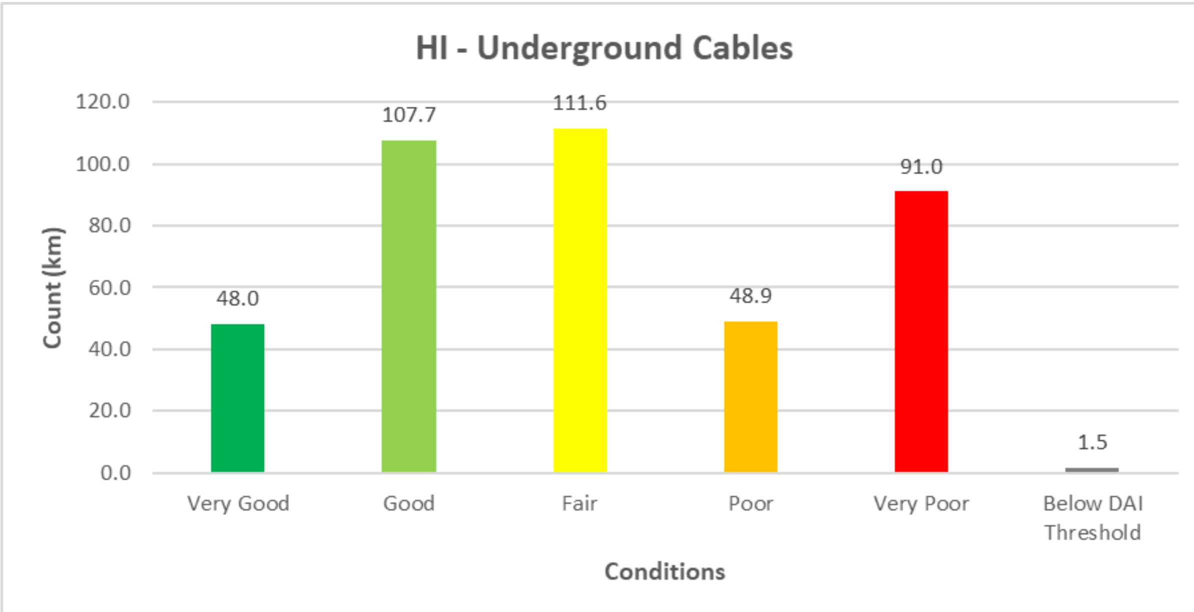
In 2018, a near-miss incident involving a submersible transformer prompted EPI to accelerate its efforts to phase out this type of equipment. Following an inspection in 2018 to identify units requiring immediate replacement for safety reasons, EPI has continued periodic inspections in compliance with ESA requirements while prioritizing the replacement of these units through targeted conversion projects. Incremental System Renewal investments over the 2021-2025 Historical Period have supported this process, enabling steady progress. The remaining units are scheduled for accelerated replacement as part of EPI's ongoing commitment to safety and system reliability.

As of 2024, EPI had 161 submersible transformers, the majority of which are in Fair or worse condition. The utility is phasing out this asset class due to the increased operating costs and significant safety risks associated with underground vaults where these units are housed. The relatively small number of remaining units reflects EPI's proactive and sustained efforts to reduce the presence of this technology across its service territory. To ensure that the phase-out occurs as soon as practicable, EPI prioritizes the projects that include submersible transformer replacement ahead of other comparable projects under consideration. This phased approach ensures that safety, reliability, and cost-effectiveness remain top priorities in asset management.

4.2.2.3.2.2 Underground Primary Cables

EPI owns approximately 408.8 km of underground primary cable within its service territory, spanning five types: XLPE (Cross-linked polyethylene), TRXLPE (Tree-retardant cross-linked polyethylene), BR (Bare Neutral), PILC (Paper-insulated lead-sheath cable), and PVC (Polyvinyl chloride). Like many of its Ontario peers, EPI inherited incomplete records regarding the types of cables installed by its various predecessor utilities, leaving approximately 30% of these assets with an unknown insulation type. For the 2024 ACA, underground cables were grouped into three categories based on similar service ages to apply typical useful lives as an age-based condition parameter: Age Band 1 (XLPE, BR, PVC, and Unknown), Age Band 2 (TRXLPE), and Age Band 3 (PILC). Additionally, the 2024 ACA introduced a new condition parameter, peak loading, to incorporate operating conditions into the cable Health Index assessment. Figure 32 provides the results of this updated analysis for underground cables.

Figure 32: Underground Primary Cable ACA Results



Among these, XLPE cables are in the poorest condition cohort due to their relatively short service life, making them the most likely candidates for renewal in the near to medium term. The aging cohort of PILC cables is also noteworthy. While these assets remain within their expected useful life, they are primarily located on the legacy voltage system and are decommissioned as part of voltage conversion projects in their respective areas. The decommissioning PILC cables incurs additional costs due to the environmental considerations required for their safe and responsible removal.

4.2.2.3.2.3 Other Asset Classes

Please see Attachment B for the complete 2024 ACA report, which includes discussion of several additional asset classes not covered in the above summary, such as Station Batteries, Station Yards, Pole-trans and Platform Transformers. Remaining asset classes covered by the ACA but not included do not drive material investments.

Station batteries and yards are addressed through maintenance activities, and generally do not drive capital expenditure.

Pole-trans and platform transformers are obsolete equipment types that have been fully retired through conversion activity since the completion of the 2024 ACA.

4.2.2.4 Feeder and Substation Capacity

EPI regularly monitors the loading levels of its feeders and distribution stations to ensure that available system capacity continues to meet current requirements and near-term load growth projections.

For station assets with the highest loading levels or other known risk factors, the utility deploys modernized Protection and Control devices to manage risks effectively.

Table 4-8 showcases that the utilization levels of EPI's substations indicate no immediate capacity constraints. This aligns with EPI's strategy to phase out legacy substation infrastructure as it gradually converts low-voltage feeders to the standard 27.6 kV voltage. While the utility continues to monitor station capacity and address emerging issues, it does not anticipate significant capacity-related substation investments in the Forecast period.

Table 4-8: Substation Loading and Capacity Utilization

TS/DS Name & Town	Capacity (MVA)	2020 Peak Load (MVA)	2021 Peak Load (MVA)	2022 Peak Load (MVA)	2023 Peak Load (MVA)	Avg % Utilization
Ridgetown						
RICT1	3	2.08	1.97	1.90	2.40	70%
RITT1	3		1.50	1.87	0.96	48%
Blenheim						
BLET1	5	3.47	3.44	3.55	4.02	72%
Wheatley						
WHT1	2	1.01	1.05	0.80	1.11	50%
Chatham						
SUB1T1/T2	20	2.13	2.12	2.13	1.20	9%
SUB3T1	7.5	4.41	3.13	1.61	1.73	36%
SUB4T1/T2	5	0.85	0.67	1.25	0.66	17%
SUB6T1	6	2.08	1.38	2.10	1.67	30%
Strathroy						
MPSUB1	5	4.11	2.75	2.68	4.24	69%
MPSUB3	3	0.93	0.90	0.74	0.47	25%
MPSUB4	3.8	1.64	1.66	1.80	1.36	43%
Parkhill						
MPSUB5	5	2.67	2.55	2.71	3.26	56%
St. Thomas						
SUB9	3	0.15	0.04	0.04	0.04	2%
SUB11	3	0.32	0.26	0.32	0.28	10%
SUB14	3	0.15	0.19	0.13	0.00	4%
SUB15	3	0.00	0.00	0.00	0.00	0%

In addition to station monitoring, EPI actively tracks the loading levels of individual feeders. Historically, feeder capacity constraints have primarily occurred during temporary system configurations associated with the multi-year voltage conversion of the legacy low-voltage distribution network. To align with its voltage conversion strategy, EPI avoids expenditures to expand or reinforce low-voltage feeders for new load connections. Whenever feasible, EPI refrains from connecting new services to low-voltage feeders.

For connection requests with anticipated demand exceeding 500 kW, EPI's Planning department conducts assessments as part of the regular connection application process to determine if the load can be cost-effectively connected to the 27.6 kV system. If capacity constraints arise on the 27.6 kV feeders, EPI addresses them through load transfers or other appropriate actions, ensuring efficient and reliable service delivery.

4.2.2.5 Upstream Capacity

By virtue of its 17 communities spanning four Ontario Regional Planning Zones, EPI is also constantly engaged in activities that explore its system's impact on the upstream Hydro One assets. Historically, there have been two instances during the Historical Period where the Regional Planning process identified capacity and/or reliability opportunities with upstream supply assets that serve EPI (Strathroy TS and Kent TS T3). In both cases, EPI and the upstream supplier collaborated on detailed technical studies to confirm the results of higher-level analysis conducted through Regional Planning. As described in Section 3.2.6, EPI has shown a continued participation in the Integrated Regional Resource Plan process and described the findings obtained through the latest round of collaborations as well as internal load analysis.

To enable its participation in the Regional Planning activities and ensure effective monitoring of its own downstream capacity needs, EPI maintains and periodically updates a station-level load forecasting model. The analysis methodology used in the forecast model relies on the industry published data by the IESO in its Annual Outlook Forecast, historical loading information, and local trend data as required. In addition to the quantitative forecasting results, EPI also considers other sources of planning information, obtained through consultation efforts described in Section 3.2, as well as the outcomes of specific discussions with current and potential customers in the context of its connection application process. Consistent with the principles of the Regional Planning work, prior to commencing any system capacity expansion planning to accommodate new load, EPI considers less costly opportunities that may be available through load transfers or other modifications to the existing system, such as changes to the protection schemes, reconductoring, or the implementation of a NWS.

By integrating the econometric forecasts, technical engineering analysis and more qualitative insights (such as anticipated zoning changes in the municipalities it serves) EPI can assess its upcoming capacity needs in a holistic manner. Section 5.1 provides a practical example of this holistic approach by discussing the expected evolution of EPI's system over the Forecast Period and the ensuing System Service investments included in the Plan.

4.2.3 Transmission or High Voltage Assets (5.3.2c)

EPI does not have any transmission or high voltage assets that the OEB has previously deemed to be distribution assets.

4.2.4 Host and Embedded Distributors (5.3.2d)

EPI is a partially embedded distributor, with 23 of its 36 total supply points embedded in the upstream host distributor's system, as identified in Table 4-13. For all 23 embedded supply points, the host distributor is Hydro One Networks Inc. These embedded supply points account for 37.6% of EPI's total load. Section 4.4 summarizes the supply configuration (embedded vs express) of all EPI-served communities. Refer to Table 4-8 for details on the capacity and average utilization rates of EPI-owned distribution stations.

4.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

EPI seeks to maximize the productive value of all assets in its care by relying on insights generated through different stages of the Asset Management Process described in Section 4.1.2. While Section 4.1.2 lays out the fundamentals of its approach to asset lifecycle optimization, this section of the DSP describes the specific types of asset intervention activities (e.g. inspection, maintenance, replacement, refurbishment) applicable to different types of equipment and operating circumstances.

4.3.1 Asset Replacement and Refurbishment Practices (5.3.3a)

4.3.1.1.1 Replacement vs. Refurbishment

EPI's asset management strategy balances the need for refurbishment and renewal, particularly as it transitions to a unified, single-voltage distribution system through its Voltage Conversion program. A key focus of this strategy is determining the optimal approach for maintaining and replacing aging infrastructure, such as substations and low-voltage feeders, to ensure reliability and cost efficiency. This involves carefully evaluating whether to proactively refurbish critical assets, run them to failure, or replace them outright as part of broader system upgrades.

As EPI progresses with its Voltage Conversion program, it is steadily moving toward a unified 27.6kV distribution system, which will eliminate the need for legacy distribution substations. To avoid costly reinvestments in aging substation infrastructure, EPI aims to decommission these assets before they reach the end of their useful lives. In practice, this means that the conversion of feeders originating at each station must be completed before the station assets reach their end of life.

Aside from ensuring that conversion activities proceed as planned, this phase-out strategy involves conducting comprehensive inspection and testing activities for the substations. Implementation of this plan provides relatively few practical opportunities for near/medium-term line asset intervention options (i.e. proactive refurbishment). This is largely because much of EPI's oldest and most deteriorated line assets are located on low-voltage feeders that the utility is converting to a new utility-wide 27.6 kV standard. Accordingly, it is EPI's preference to avoid making any incremental renewal investments in the low-voltage feeders aside from smaller reactive fixes driven by individual asset failures, weather damage, or other forms of external interference.

While substation infrastructure (e.g. power transformers) is often considered to be a primary candidate for major refurbishment work, EPI generally expects to phase out its substations before their major components reach end of life. EPI acknowledges that substation asset refurbishments will be required in some cases, particularly if the rate of substation asset deterioration deviates from its current expectations. Where substations are expected to remain in service for a significant length of time, EPI evaluates if improvements to P&C or advanced asset monitoring systems are prudent investments. See Section 3.3.1.1.2 and Section 3.3.2.1 for additional details on substation equipment monitoring and testing and smaller reactive fixes.

Based on the above considerations, the scope of refurbishment practically applicable to EPI's electrical assets entails the following:

- Revenue meter re-sealing, where permitted by Measurement Canada standards;
- Repurposing of distribution transformers, particularly when upsizing is required early in their lifecycle due to conversion work or changing customer demands; and
- Life-extension activities for unique or high-value assets, such as SCADA-controlled switches

The dedicated subsections that follow address the relevant Replacement vs. Refurbishment decision criteria applicable to the General Plant assets.

4.3.1.1.2 Proactive vs. Reactive Asset Replacement

EPI believes that it is neither practical nor economically efficient to prevent all asset failures in the field through proactive replacement – whether this failure represents an actual operating asset malfunction, or an inspector's opinion that the asset has reached its end of useful life and must be replaced in short order. As such, the Run to Failure asset replacement approach is the default strategy EPI assumes during risk-based power system planning analysis (subject to the important exceptions noted below). Where these risks are deemed unacceptable, specific assets are referred for proactive replacement. Assets typically referred for proactive replacement generally can be characterized as having a high impact to system reliability during failure, and a difficult or long replacement process. Examples include feeder egress cables and river, rail and highway crossings. This mix of reactive and proactive replacement balances the needs of system maintenance and system reliability against the need to minimize costs by maximizing equipment value by running assets to failure. This approach enables the utility to anticipate and budget for a certain volume of individual overhead and underground asset failures in each given year. When individual line assets fail in service or are deemed to have failed by way of inspections, EPI will screen the anticipated work in the near/medium term in the vicinity to see whether it may make sense to upsize the failed unit to a higher standard in anticipation of other proactive work occurring in the area (e.g. conversion).

A variation of this hybrid Run to Failure approach is also consistent with EPI's strategy regarding substation assets, which the utility seeks to phase out before they reach their respective ends of useful lives. While station assets are typically seen as primary candidates for proactive replacement due to their failure impact magnitude and long equipment lead times, EPI plans to make them redundant through the ongoing conversion of low-voltage feeders that emanate from them. While EPI is not looking to replace the substations, it is critically important to ensure that the existing station assets stay in service until the downstream conversion work is completed. To this end, EPI invests significant resources into substation equipment condition monitoring (e.g. Dissolved Gas Analysis) and life extension activities (breaker timing tests, transformer drying, P&C upgrades, etc.). As such, while EPI plans to run these assets to failure and not replace them – it is a key priority (and O&M driver) for EPI to ensure that the failure does not occur before the surrounding system is ready to accommodate it.

To enable the Run to Failure strategy for the station assets, EPI relies in a major way on proactive asset replacement planning and execution – most notably through the planned Voltage Conversion program that seeks to replace large sections of overhead and/or underground low-voltage feeders with standard

27.6 kV infrastructure. Given that Voltage Conversion Work proactively targets geographically and electrically adjacent areas and involves the application of new technical standards (rather than like-for-like renewal), this approach enables EPI to capture scale economies in the engineering and design work, equipment procurement, materials staging and outage coordination work, among others.

Aside from the voltage conversion work, EPI also utilizes proactive replacement when dealing with higher-criticality assets, such as larger distribution transformers, three-phase overhead line assets, or DA infrastructure. Similarly, EPI is phasing out submersible transformer units from its underground system, given the higher operating costs and additional safety risks involving work in confined spaces.

4.3.1.1.3 Equipment Ratings and Renewal

When replacing assets, EPI generally adheres to a like-for-like replacement approach in terms of service type, and core technology. Reactive replacements are primarily equivalent for equipment ratings, while planned replacements seek to apply EPI current equipment sizing standards. Exceptions to this include upgrades driven by customer-driven facility enhancements, and the removal of outdated technologies, such as porcelain insulators and pole-trans transformers.

4.3.1.1.1 Overhead vs. Underground Asset Renewal

EPI is aware that some Ontario utilities are actively working to convert greater portions of their systems to overhead (or underground) service configurations depending on operating issues surrounding the status quo arrangements. Notwithstanding the validity of such strategies in some parts of the province, EPI's default approach is to retain the original service configuration after conversion – replacing overhead lines with new overhead lines and vice versa. Importantly, when removing segments of direct-buried cable through voltage conversion or outage mitigation work, EPI replaces them with segments encased in rubberized or concrete ducts to prolong the useful life of new equipment and make the eventual replacement more cost effective.

4.3.2 Description of System Operations and Maintenance Practices (5.3.b)

4.3.2.1 Substation Inspection and Testing

EPI staff inspect its substation assets every month to identify any emerging equipment failure/malfunction risks, or safety hazards through visual observation of the signs of degradation, confirmation of equipment readings, or identifying signs of compromised structural integrity within or between components. Battery testing procedures vary between stations depending on the capabilities of installed equipment, ranging from monthly voltage readings through continuous SCADA monitoring and bimonthly shallow drain tests. To the extent possible, EPI seeks to mitigate any identified battery-related deficiencies on the spot.

To ensure that its major station assets remain in an adequate operating condition, EPI subjects its population of station transformers and breakers to multiple empirical tests and detailed component inspections. These activities, performed by a combination of third-party experts and internal staff, are shown in Table 4-9.

Table 4-9: Substation Maintenance Schedule Highlights

Asset Class	Maintenance and Inspection Activity	Frequency
Substation Transformers	Oil Dissolved Gas Analysis (“DGA”) Testing	Annual
	Oil Quality and Oil Level Testing	Annual
	Insulation Power Factor Testing	3 year
	Oil Leaks Identification	Monthly
	Transformer Bushing Condition Inspection	Monthly
	Overall Unit Condition Inspection	Monthly
Circuit Breakers	Contact Resistance Tests	3 year
	Insulation Resistance Tests	3 year
	Control and Operating Mechanism Testing	3 year
	Overall Breaker Condition Inspection	3 year
	Coil Signature and Arc Chutes Tests (as applicable)	3 year
Station Switches	Visual Inspection	Monthly
	Contact Cleaning	3 year
Station Batteries	Visual Inspection	Monthly
	Battery Health Testing	Annual
Station Yards	Visual Inspection	Monthly
	Resistance Testing	3 year

EPI uses the results of the above inspection and testing activities to compile asset HIs during periodic asset condition assessment reports. Other station assets, including the civil infrastructure, undergo visual inspections to ensure that they remain in regular working order and meet the requisite safety standards. See Section 4.3.2.1 for the results of the latest station asset condition assessment.

4.3.2.2 Line Infrastructure Inspection and Maintenance

EPI inspects its line infrastructure on a regular three-year cycle, in accordance with the Distribution System Code’s minimum inspection requirements (Distribution System Code, Appendix C).

As noted elsewhere in this document, EPI follows the exception-based reporting methodology, where patrol staff generate exception records in cases where follow-up in the near-term is seen as necessary to avoid failures or mitigate safety risks. This approach forms the first line of asset prioritization at EPI. With the enhancements to asset data reporting and processing discussed in Section 4.2.2.1, the exception reporting strategy gives EPI planners a quick and efficient way to obtain new information and incorporate it into near-term fieldwork plans.

4.3.2.3 Overhead Assets

The current overhead line patrol approach entails visual inspection of poles, conductors, crossarms, insulators and other pole-top infrastructure as relevant. Overhead transformers undergo Infrared ("IR") scans to identify any potential hotspots indicative of impending failure. Aside from looking for signs of normal wear and tear, overhead line patrols identify evidence of vandalism, unreported minor damage from vehicular collisions or weather events, or excessive vegetation within or near the right-of-way.

Historically, EPI has subjected a small, randomly generated subset of wood poles to drill testing each year. This approach enabled the use of statistical sampling techniques to draw directional inferences about the health of the overall population. EPI has implemented a cyclical pole drilling program. Although the first cycle has not yet been completed, significant information has already been gathered, influencing engineering decisions (see Section 4.2.2.3.1). EPI also conducts drill tests in response to marginal visual inspections or during planned work where asset age and condition lead to challenging "keep or replace" decisions, with pole test results acting as a potential tiebreaker. In 2022 EPI updated its pole drilling standard to include additional information. The latest 2024 ACA included the results of the drill test in the HI formulation for Wood Poles. Currently, 55% of wood poles have the drill test conducted. EPI plans to continue collecting the test results for the remaining poles and, with the 2025 addition of the Data Scientist position, will continue refining its approach to data science-driven health assessments over the forecast period.

Vegetation contacts can cause sustained interruptions for EPI's customers. The utility employs proactive tree trimming activities on a four-year cycle. Over the forecast period, as supported in customer engagement (see Section 3.2.1.2), EPI will implement a satellite-imagery-based initiative to enhance its vegetation management program. EPI currently relies predominantly on external contractors to conduct cyclical vegetation trimming work, while project-specific staging activities (such as trimming ahead of conversion work) are completed by internal crews.

Table 4-10 summarizes the maintenance and inspection activities performed on the Overhead Assets by EPI.

Table 4-10: Overhead Asset Maintenance Schedule

Asset Class	Maintenance and Inspection Activity	Frequency
Distribution Poles	Visual Inspection	3 years
	Thermal Inspection	3 years
	Drill testing (Wood only)	10 years
Overhead Transformers	Visual Inspection	3 years
	Thermal Inspection	3 years
Overhead Switches	Visual Inspection	3 years
	**Additional tracking on operation	

4.3.2.3.1 Underground Assets

Underground system patrols involve visual inspections and minor maintenance of above-grade assets such as padmount transformers and risers. As a part of the inspection, crews check and note any material deficiencies in the following parameters: accessibility, grade, obstructions, security, tank, paint, foundation, bollards, identification, and check for oil leaks. Crews also perform an infrared scan and confirm if the transformer is shown correctly on the grid maps with the correct address and information shown on the existing transformer spec sheets.

EPI also inspects the integrity of its cable chamber lids once every ten years using the services of a qualified civil engineer. As the utility is phasing out submersible transformers, it will continue to actively patrol and maintain the units that remain in operation. Maintenance will be undertaken on these vaults only on an as-needed basis. To ensure that the phase-out occurs as soon as practicable, EPI prioritizes the projects that include submersible transformer replacement ahead of other comparable projects under consideration.

Table 4-11 summarizes the maintenance and inspection activities performed on the Underground Assets by EPI.

Table 4-11: Underground Asset Maintenance Schedule

Asset Class	Maintenance and Inspection Activity	Frequency
Padmount and Submersible Transformers	Visual Inspection	3 years
	Thermal Inspection	3 years

4.3.3 Processes and Tools to Forecast, Prioritize and Optimize System Renewal Spending (5.3.3c)

EPI employs a robust approach to forecast, prioritize, and optimize system renewal spending, ensuring alignment with budget envelopes and strategic objectives. This approach balances the need for reliability with capital expenditure costs, considers potential risks, and plans for future capacity requirements to avoid premature asset replacement. The overall approach to identifying and forecasting capital spending is outlined in Section 4.1.3, including prioritization and optimization of renewal needs and life-cycle cost considerations when making decisions.

4.3.3.1 Forecasting System Renewal Spending

For forecasting system renewal spending, EPI utilizes a multi-faceted forecasting process that integrates various data sources and analytical tools to estimate future system renewal needs. Key components of this process include:

- ACA: EPI gathers detailed inspection and testing data for its major electrical system assets and conducts regular condition assessments using condition-based and age-based degradation parameters. This includes visual inspections, infrared scans, and drill tests for poles, as well as detailed testing for substation equipment like transformers and circuit breakers.

- Performance monitoring: System performance is continuously monitored through reliability modeling, power quality monitoring, and system loss tracking. This data helps identify assets that may require intervention due to declining performance or increased failure rates.
- System utilization analysis: EPI assesses the utilization of its assets to determine if enhancements or expansions are needed. This includes load forecasting and analyzing the impact of new customer connections and regional planning recommendations.

ACA results play a crucial role in informing EPI about asset renewal needs by categorizing assets into different HI categories. These assessments help forecast future renewal requirements by identifying assets that are approaching the end of their useful life or showing signs of significant deterioration. By systematically evaluating the condition of assets, EPI can prioritize which assets need immediate attention and which can be scheduled for future renewal, ensuring a proactive approach to asset management.

The Voltage Conversion program is central to EPI's strategy for forecasting renewal needs. This program focuses on the proactive replacement of large sections of low-voltage feeders fed from legacy distribution stations with standardized 27.6 kV infrastructure. By doing so, EPI aims to replace aging and deteriorating assets before the costly substation assets fail. This approach not only addresses the immediate need for renewal but also aligns with long-term strategic goals by modernizing the infrastructure. Legacy feeders, often the oldest and in the worst condition, are planned for proactive replacement, ensuring that the most critical areas are addressed first.

In addition to infrastructure renewal, the aging population of smart meters requires significant investment. EPI was an approved early adopter of smart meters and approximately 65% of EPI's fleet of smart meters will have reached the end of their first or second re-seal period as specified by Measurement Canada. As some meter batches have, and will continue to inevitably fail these tests, EPI is obligated to replace them to comply with regulatory standards. This replacement program is considered non-discretionary spending, similar to the System Access program, which addresses new customer connections and system expansions. Given the potential fluctuations in these non-discretionary programs, EPI may need to adjust System Renewal budgets to maintain the overall investment level within approved budgets.

4.3.3.2 Prioritizing and Optimizing System Renewal Spending

To prioritize and optimize capital expenditures, EPI employs a structured approach that considers lifecycle cost optimization, criticality analysis, and strategic fit assessment:

- Lifecycle cost optimization: EPI evaluates the total lifecycle costs of assets, balancing the declining capital costs of existing assets with the increasing risk costs associated with deteriorating infrastructure. This analysis helps determine the economically viable time for asset replacement or major intervention.

- Criticality analysis: Investments are prioritized based on their criticality, which is assessed through several dimensions: safety, critical loads and network criticality, equipment risks, business continuity, and compliance.
- Strategic fit: Potential investments are evaluated against EPI's AM Objectives, ensuring alignment with the utility's broader strategic goals. This assessment allows for managerial flexibility and the use of discretionary judgment in decision-making.

EPI optimizes system renewal spending through a strategic blend of proactive and reactive approaches, ensuring resources are allocated efficiently. Proactive replacement programs are implemented for high-criticality assets and those identified through detailed condition assessments. A key component of this strategy is the Voltage Conversion program, which focuses on replacing aging low-voltage feeders with standardized 27.6 kV infrastructure. This proactive approach ensures that critical and costly station assets are decommissioned before they fail and aging low-voltage legacy assets are upgraded to enhance system reliability and performance.

For less critical assets, EPI employs a run-to-failure strategy, where reactive maintenance and replacements are conducted as needed. This approach is complemented by proactive monitoring and life extension activities for critical assets, aimed at limiting premature failures and extending the operational life of these assets. By balancing proactive and reactive strategies, EPI ensures that both immediate and long-term system renewal needs are met effectively.

To support effective decision-making, EPI employs a capital spending prioritization process that assigns specific weightings to each of its six AM objectives. Each project is weighted, allowing asset managers to navigate trade-offs between competing priorities. This structured approach ensures a balanced consideration of operational, financial, and stakeholder impacts, enabling EPI to make informed investment decisions that align with its strategic goals and deliver maximum value to its customers.

4.3.3.3 Operating Within Budget Envelopes

EPI ensures that its system renewal spending operates within budget envelopes through rigorous financial planning and resource allocation:

- Budget constraints: Top-level budgetary constraints are balanced against system renewal needs, with capital and O&M resources allocated to the most pressing and high-risk areas and assets.
- Exploring alternatives: EPI evaluates alternatives to traditional capital investments, including non-wires alternatives and demand response programs, to identify cost-effective solutions.
- Execution optimization: Detailed planning and preparatory activities are conducted to ensure efficient execution of capital projects, including technical design, scheduling, procurement, and stakeholder coordination.

By integrating these processes and tools, EPI effectively forecasts, prioritizes, and optimizes system renewal spending, ensuring reliable and cost-effective electricity services for its customers.

Additional details on the annual capital planning process can be found in Sections 4.1.3 and 5.2.1.

4.3.3.4 Risk of Proceeding/Not proceeding

EPI carefully considers the potential risks associated with proceeding or not proceeding with individual capital expenditures. This risk assessment includes:

- Operational risks: Evaluating the impact on system reliability and performance if a project is deferred or canceled. This includes the potential for increased outages, equipment failures, and safety hazards.
- Financial risks: Assessing the cost implications of delaying investments, such as unproductive costs associated with legacy station asset upgrades when they could be decommissioned rather than renewed, higher emergency replacement costs, and increased maintenance expenses.
- Customer impact: Considering the effect on customer satisfaction and service quality, including the potential for reduced reliability weighed against higher distribution rates, and overall customer satisfaction.
- Regulatory compliance: Ensuring that deferring or canceling projects does not lead to non-compliance with industry regulations and standards.

By thoroughly evaluating these risks, EPI ensures that its investment decisions are well-informed and aligned with its strategic objectives.

4.3.3.5 Consideration of future capacity requirements

EPI places significant emphasis on ensuring that system renewal decisions are aligned with anticipated load growth and electrification trends to avoid premature asset replacement due to capacity constraints. This forward-looking approach is integral to strategic planning and asset management processes.

To address the uncertainty in timing and the uneven distribution of anticipated load growth across EPI's service territory, EPI has updated its engineering design and transformer sizing standards. The new standard increases the per-customer capacity allocation to 6 kVA (with an option for 12 kVA), reflecting anticipated long-term increases in residential customer demand due to DERs (including EVs and heat pump adoption). This standardization also involves the use of 100 kVA transformers, replacing the legacy 50 kVA and 75 kVA units, to better accommodate future load increases.

Additionally, EPI has updated the civil engineering design as well as primary and service cable layouts to enable cost-effective bus-splitting. This design allows for the doubling of transformation capacity per customer with minimal incremental costs as load develops. Transformer bases are now designed to accommodate larger 166 kVA units, providing the flexibility to triple capacity in the future without incurring additional civil costs. These updates ensure that our infrastructure can adapt to increasing demand efficiently and cost-effectively while avoiding oversizing assets in the near term.

By incorporating these considerations into renewal decisions, EPI ensures that its system remains robust and capable of meeting future capacity requirements. This proactive approach helps prevent the need for premature asset replacement due to capacity constraints, thereby optimizing EPI's investment in system renewal and maintaining reliable service for its customers.

4.3.4 Important Changes to Life Optimization Policies, Processes, and Tools since Last DSP Filing (5.3.3d)

As already outlined in Section 4.1.2, EPI has made several changes in its asset management processes to enhance decision-making, reliability tracking, and readiness for future system needs. These changes reflect the utility's commitment to continuous improvement and alignment with industry best practices. The changes related to lifecycle policies and tools have been modest and include the following:

- Enhanced data collection and ACA methodology: Transition from single-parameter (age-based) to multi-parameter (condition-based) assessments for nearly all asset classes. This shift enables more effective targeting of capital programs by providing a comprehensive view of asset health.
- Lifecycle cost approach: Enhanced lifecycle cost analysis processes now consider costs at both the individual asset level and the system level, and consistent validation of the prioritization of voltage conversion and replacement in lower-voltage networks over equivalent-condition assets in the 27.6 kV network. This includes evaluating lifecycle costs on a circuit-by-circuit basis, accounting for critical and costly upstream assets such as substations.
- Design and capacity planning: Updated engineering standards to address anticipated long-term increases in residential customer demand due to electric vehicles and heat pump adoption.
- Fleet management: Increased vehicle replacement time horizon of fleet vehicles by one year to optimize capital expenditures, reflecting the improved quality and reliability of new vehicles.
- Tree trimming: Standardized tree trimming intervals to four years across the service territory to enhance vegetation management efficiency.

4.4 Capacity Planning

EPI is a Partially Embedded Distributor. Thirty eight percent (38%) of it's load was served through embedded points in 2024. EPI serves 17 communities across Southwestern Ontario, utilizing a mix of distribution voltages (4 kV, 8 kV, and 27.6 kV) and varying supply arrangements. These communities are supported through three primary types of supply connections: express connections, embedded feeders, and Distribution Stations ("DS").

Express connections are dedicated feeders directly linked to Hydro One's TS, offering the highest capacity and operational flexibility. Embedded connections, on the other hand, connect to Hydro One's distribution network and provide less capacity and flexibility but adequately serve communities without their own costly transmission stations. Finally, DS connections represent legacy low-voltage networks supplied either through express or embedded feeders. These connections generally have limited capacity and capabilities.

The table below summarizes the supply arrangements for each of the 17 communities in EPI's service area:

Table 4-12: Communities with supply type

#	Community	Supply Type
1	Blenheim	Embedded
2	Bothwell	Embedded
3	Chatham	Express
4	Dresden	Embedded
5	Dutton	Embedded
6	Erieau	Embedded
7	Merlin	Embedded
8	Mt Brydges	Embedded
9	Newbury	Embedded
10	Parkhill	Embedded
11	Ridgetown	Embedded
12	St Thomas	Express
13	Strathroy	Express + Embedded
14	Thamesville	Embedded
15	Tilbury	Express + Embedded
16	Wallaceburg	Embedded
17	Wheatley	Embedded

With its diverse supply arrangements, varied demographics, and evolving consumption patterns, capacity planning in EPI's service territory is increasingly complex. The shift towards electrification including adoption of EVs and heat pumps, coupled with intensified residential development and new commercial and industrial demands, adds to these challenges.

As covered in Section 3.2.6, EPI actively participates in regional planning processes, such as the Integrated Regional Resource Plan, to coordinate capacity investments across service territories as classified by the IESO. EPI's capacity planning activities are fully integrated into its capital planning process. EPI's regional planning activities are complemented by internal analyses that evaluate feeder and station-level capacity, load consumption patterns, and growth projections based on historical trends and anticipated developments. IESO's load projections, which incorporate province-wide intensification, also inform this process.

To address capacity constraints, EPI monitors its system closely, identifying when distribution supply in a community nears critical loading limits. In such cases, the utility collaborates with host distributors or transmitters to secure additional supply. For example, in 2025, EPI is working with Hydro One on the installation of a new breaker at Edgeware TS, from which EPI will build a new emanating feeder to address existing capacity constraints.

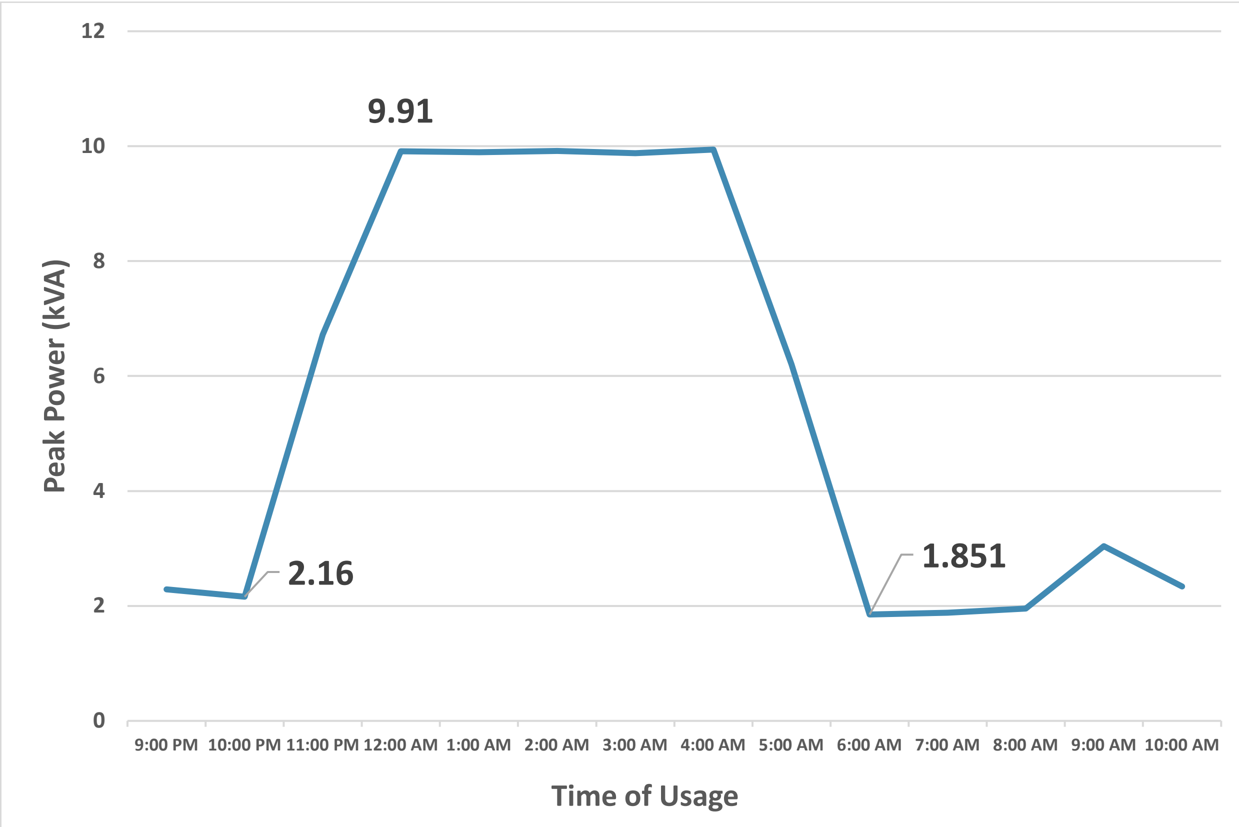
4.4.1 Residential Load Growth and Housing Mandates

The residential sector, comprising over 90% of EPI's customer base, is a primary driver of load growth. Recent subdivision developments, coupled with government housing mandates such as Ontario's Bill-23: More Homes Built Faster Act (2022), are expected to sustain this growth. As residential electrification accelerates – driven by the adoption of EVs, heat pumps, and other electric technologies – demand will continue to rise.

4.4.2 Impact of Electrification and New Engineering Standards

Ontario's energy transition toward the federal net-zero goals of 2050 is steadily impacting EPI's distribution network. EPI is seeing a steady penetration of EV chargers into its distribution network. With a large residential population and a high percentage of single-family detached homes, EPI expects residential chargers to represent a significant new load type within its network as EV chargers impose significant loads during operation. This can be seen in Figure 33, which shows the magnitude of the loading increase of a residential charger as measured against one of EPI's customers. Other EVs accept chargers with twice this charge rate, potentially doubling the system demand.

Figure 33: EV Power Usage Profile



Historically, EPI has used a capacity allocation of between 3 kVA and 5 kVA per residential customer. In the long term, residential customer demand is expected to reach and exceed 12 kVA per customer with the deployment of EVs and heat pumps. At these loading levels, concurrency becomes a key factor in determining the correct investment levels. In response to the uncertainty in timing, customer usage patterns and the unevenness of the anticipated load growth across its territory, EPI has updated its engineering design standards to provide a scalable solution which avoids oversizing assets in the near term. Section 4.3.3.5 details the features of EPI's phased transition to new design standards.

As customer usage patterns and preferences for interacting with the distribution system change and evolve over the coming years, it will become increasingly important to have increased visibility and understanding of its distribution system to allow it to continue to pace anticipated required asset upsizing and replacement. EPI already has a wealth of data available for analysis from its Smart-metering system, GIS and SCADA Data historian. Application of increasingly advanced analysis techniques against this data (including the use of machine learning and AI technologies) will allow EPI to continue to optimize spending and maintain pacing of its investments by identifying emergent needs prior to them causing a failure. This also will promote a shift from reactive to proactive replacement, as reactive replacement where asset upsizing is required is very inefficient and expensive compared to like-for-like reactive replacement.

4.4.3 Commercial & Industrial Customer Base

Although fewer in number, Commercial and Industrial customers can drive significant demand growth, often requesting unprecedented load capacities. These connections can quickly deplete available capacity, especially in areas poised for industrial or commercial development. As a utility which is fully embedded within Hydro One TX and DX, load growth within the adjacent utility can impact available capacity. For instance, while Tilbury currently has 9.9 MVA of available capacity, sufficient to support its projected residential load growth of 4 MVA, it faces potential capacity constraints due to a pending connection request from another distributor for an EV charging park located in that distributor's service territory with a peak load of 8.3 MVA. This connection may reduce the available capacity to near zero, potentially necessitating a capacity upgrade in the near term. EPI is aware that two emerging end uses, EV charging parks and data centres, are absorbing significant capacity for other utilities. In addition, the magnitude of preliminary load request from existing industrial customers, as well as finalized connection agreements, are getting larger. While EPI does not currently plan to file any ICM applications during the 2026-2030 period, given the above dynamics and the evolving provincial energy policies and increasing load at EPI's 36 supply points, capacity needs may arise that require the filing of an ICM application. EPI expressly reserves the right to do so if needed.

To manage such scenarios, EPI carefully tracks in-progress C&I applications with signed contracts or strong connection interest, incorporating these into its peak contribution analysis for community-based load forecasts. This proactive approach ensures realistic capacity planning that accounts for sudden swings in demand.

4.5 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources (5.3.4)

EPI operates 63 distribution feeders across all voltage levels and communities, enabling power delivery to a diverse customer base. The integration of DERs is subject to various system constraints, which can arise from feeder or station-level conditions. As a highly embedded distributor served exclusively by Hydro One-owned transmission stations, EPI assesses these connection requests collaboratively with its host utility.

4.5.1 Station-Level Restrictions

Certain feeders within the EPI network have been identified by Hydro One as restricted due to station-level limitations. These restrictions are managed through direct communication and negotiation with Hydro One, as well as via the regional planning process to address capacity and operational challenges. Currently, the following feeder has a station-level restriction:

Table 4-13: Feeders with Station-Level Restrictions

Town	Station	Feeder	Customer Count
Wheatley	Leamington TS	393M22	213

4.5.2 Embedded Feeder Restrictions

EPI also operates several feeders embedded within Hydro One's distribution system. At present, these feeders face no restrictions. If upstream constraints were to arise, EPI would collaborate with Hydro One to identify solutions, although direct remediation options may be limited due to the shared nature of the feeder infrastructure.

4.5.3 EPI-owned Feeder Restrictions

Several EPI-owned feeders are restricted due to local conditions. The following table lists EPI feeders with identified restrictions:

Table 4-14: EPI-Owned Feeders with Restrictions

Town	Station	Feeder	Customer Count
Chatham	Sub 3	3F03	188
	Sub 4	4F08	52
	Sub 6	6F02	98
	Kent TS	5M8	775
Ridgetown	Ridgetown Tecumseh	RITF1	250
		RITF2	319
St Thomas	Sub 9	9F4	30
	Sub 11	11F1	86
		11F3	125
		11F4	27
Strathroy	Sub 23	23F2	258

Excluding Kent TS 5M8, which serves a large industrial site with self-generation, these restricted feeders are part of EPI's legacy low-voltage distribution system. Conversion is expected to relieve these restrictions for served customers. Twelve of these feeders are expected to be fully converted and decommissioned by 2026. Restrictions on these feeders are driven by feeder and station loading conditions rather than DER generation density.

For customers interested in connecting DERs on restricted feeders, EPI offers connections to the nearest supply point with available capacity as all these communities have 27.6kV distribution network. This ensures that DER integration is facilitated without overloading constrained feeders, while also aligning with the utility's ongoing efforts to modernize its system through voltage conversion.

4.5.4 Costs to Accommodate and Connect Renewable Generation Facilities

EPI has not and does not expect to incur any costs to accommodate and connect renewable generation facilities.

4.6 NWSs to Address System Needs (5.3.5)

In accordance with the OEB's Chapter 2 Filing Requirements, EPI has provided the following documentation of consideration of NWSs. EPI has used the *2024 Non-Wires Solutions Guidelines for Electricity Distributors* and its *Benefit-Cost Analysis (BCA) Framework for Addressing Electricity System Needs* to develop project screening procedures to determine when a capital project requires a BCA to clarify if a NWA may be a cost-effective option to defer or avoid traditional capital investments.

EPI's screening process excludes projects unrelated to capacity or grid optimization (such as voltage stability or transfer capacity) and those below the minimum spending threshold defined in the BCA guidelines. Eligible projects typically include supply-related system access expenditures and customer-driven system access projects requiring system reinforcements.

Customer feedback plays a critical role in shaping EPI's approach to NWSs. Feedback has revealed resistance to DR programs, with a consistent lack of interest and participation. This sentiment informs EPI's cautious approach to deploying DR or similar NWSs, ensuring alignment with customer preferences and operational feasibility (see Section 3.2.1.2 for detailed discussion on customer feedback).

EPI actively monitors supply needs driven by both organic growth and electrification trends. Under higher load growth scenarios, capacity-related investments beyond the 2025 St. Thomas capacity expansion investment, may be necessary within the 2026-2030 forecast period. However, under the base case scenario, no specific capital projects currently meet the screening criteria, and as such, no NWSs are included in the current capital plan.

EPI conducted a high-level NWS screening modelled after early BCA information for the Edgeware breaker in St. Thomas and concluded that an NWS does not currently present a technically or economically viable alternative to address the region's existing and forecasted load growth. The current four-feeder supply configuration in St. Thomas lacks the operational flexibility to allow prolonged feeder outages – whether for planned maintenance or emergency conditions - without risking widespread service interruption. The EPI capacity need was both to address existing baseload rather than just peak loading. Due to the operating characteristics required for frequent, long duration operation a high-level economic assessment indicates that the cost of a BESS unit sized to meet the identified need would be on the order of 135% to 280% higher than the budget for constructing a conventional feeder, depending on the battery cost projection scenario considered.

EPI will continue to be proactive in evaluating opportunities as system needs emerge including monitoring technology evolution, regulatory requirements, and customer needs. EPI is involved in the OEB's DSO Capabilities consultation (EB-2025-0060), and will continue to evaluate how this can act as enabling tool to allow the cost effective integration of NWS in its system.

EPI seeks to ensure its planning and investment strategies are responsive, customer-focused, and compliant with OEB guidelines. The continued monitoring and evaluation of system needs and technology evolution positions the utility to embrace innovative solutions in the future while maintaining cost-effectiveness, system reliability, operational efficiency, and alignment with customer needs.

4.7 INFORMATION TECHNOLOGY ASSET MANAGEMENT STRATEGY

4.7.1 Overall Approach

EPI's IT assets keep the utility connected, help make operations increasingly efficient and protect its data and systems from cybersecurity threats. EPI views its IT portfolio as the most dynamic portion of its asset base, as the rapidly evolving technological landscape and changing customer expectations have drastically altered the scale, scope, and complexity of EPI's IT systems over the past decade.

With shorter useful lives than most other types of utility assets, IT hardware and software lifecycle decisions arise with greater frequency and are further complicated by factors that are less relevant to other utility plants:

- **Changes in the vendor marketplace** (e.g., mergers and acquisitions affecting future offerings or support levels).
- **Past vendor support experience.**
- **Emerging cybersecurity threats** and the latest prevention and response practices.
- **Interoperability across major systems and versions.**
- **Change management work** to ensure the attainment of targeted benefits.
- **Requirements driven by customers' own technology choices.**

EPI recognizes the impact of these considerations on the cost, complexity, and performance of its IT infrastructure. Moreover, having been involved in multiple mergers and acquisitions over the past two decades, EPI has had the benefit of seeing first-hand the implications of various IT policy and strategy choices made by other utilities. Informed by these insights, the EPI's IT strategy is grounded in three pragmatic pillars:

- **Prioritize in-house skill and knowledge enhancement over outsourcing.**
- **Invest in cybersecurity to preserve resilience and business continuity.**
- **Maximize the value of core business applications over unique customized solutions.**

4.7.1.1 Prioritizing in-house capacity

A core facet of EPI's IT strategy involves prioritizing the acquisition of theoretical knowledge and practical capabilities by internal staff across various specialized disciplines such as cybersecurity, database management, and IT infrastructure. While many of its peers outsource IT asset management to varying degrees, EPI emphasizes the development of in-house expertise where it is both feasible in the short term and strategically beneficial in the long term. By focusing on specialized disciplines, EPI ensures that resources are dedicated to specific areas of IT, maximizing the knowledge and experience in constantly evolving and increasingly complex IT domains.

This approach allows the company to achieve a critical segregation of duties, ensuring that experts in each field can focus on delivering the maximum business value within their area of specialization. Cybersecurity experts can focus on securing critical infrastructure and data, database administrators can ensure optimal data management and integrity, and network infrastructure specialists can maintain seamless connectivity and system reliability. This division of labor enhances both the efficiency and quality of IT operations, while enabling a more proactive approach to managing evolving business needs and industry challenges.

Additionally, this in-house specialization helps EPI maintain consistent quality control, enabling rapid response to IT issues while aligning IT operations with long-term strategic objectives, including enhanced cybersecurity, scalability, and the ability to quickly adapt to emerging technologies. By insourcing IT talent and fostering specialization, EPI positions itself for sustained operational excellence and innovation.

4.7.1.2 Investing in Cybersecurity

With the expansion of connectivity across system assets and the increasing complexity of utility IT ecosystems, cyberattacks have become a growing threat to customer privacy, operational resilience, and business continuity. As the threat landscape evolves with the integration of advanced grid technologies, EPI is investing in robust cybersecurity measures, including vulnerability management, access control, system hardening, continuous monitoring, and rapid incident response and recovery.

In alignment with regulatory frameworks such as PIPEDA and the OEB Ontario Cyber Security Framework (“OCSF”), EPI conducts regular third-party cybersecurity assessments to validate the effectiveness of its security measures, and identify areas for improvement. These efforts protect sensitive information, maintain customer trust, and strengthen the resilience of critical infrastructure.

Additionally, EPI remains committed to reducing vulnerabilities, fortifying defenses, and swiftly detecting and responding to incidents. This includes deploying AI-driven solutions to enhance threat detection and response. Through these proactive measures, EPI safeguards its critical infrastructure and reinforces its position as a reliable utility provider in an increasingly complex threat environment.

4.7.1.3 Maximizing the value of core business applications

Recognizing its IT operations and capital resource limitations, EPI takes a pragmatic approach to enhancing productivity by consolidating applications, maximizing the usage of the Microsoft Office 365 suite and ecosystem, and reducing unnecessary complexity. The strategy focuses on leveraging existing core systems to meet business needs, avoiding new, purpose-built software unless necessary. Key elements of this approach include:

- **Minimizing customization** to ensure seamless upgrades and cost efficiency, making it easier to adopt new versions.
- **Integrating native cloud technologies** with on-premises systems to prevent data silos and maintain a single source of truth.

- **Adopting a long-term approach** to license and support maintenance to avoid costly implementation fees and ensure sustainability.
- **Maintaining a progressive upgrade cycle** to leverage new functionalities and drive productivity while containing costs.
- **Providing enhanced support and training** to empower users to fully utilize core applications and reduce the need for additional, task-specific systems.

4.7.2 Hardware Asset Management

Like many of its peers, EPI has invested in VMware-based Hyper-Converged Infrastructure (“HCI”), a software-defined approach that consolidates storage, computing, and networking resources into a single, scalable system. This eliminates the need for dedicated hardware by virtualizing resources across multiple virtual machines, reducing inefficiencies, improving resource allocation, and enhancing availability.

However, the growing demand for computing power - driven by AI, data analytics, and increased digital workloads - has significantly increased infrastructure costs. Mergers and acquisitions in the technology sector have consolidated vendor options, while post-COVID inflationary pressures have further compounded financial challenges. From 2019 to 2025, the inflation factor set by the OEB for its Price Cap Incentive Rate-setting mechanism increased cumulatively by 21%. This reflects the broader trend of elevated inflation in Canada during the pandemic and post-pandemic period, reaching its highest levels in approximately 40 years. This dynamic has led to a dramatic rise in VMware licensing costs. In response, EPI is planning to migrate to a new hypervisor solution at the end of the current server lifecycle, seeking a more cost-effective alternative that maintains performance and scalability.

Additionally, the increasing reliance on digitalization, coupled with rising cyber threats and geopolitical tensions, underscores the need for robust disaster recovery capabilities. EPI operates a dedicated disaster recovery site that must maintain sufficient computing power to fully support critical operations during emergencies. As digital transformation continues, this disaster recovery site must seamlessly take over from the primary site, ensuring service continuity in the face of disruptions caused by natural disasters, cyberattacks, or geopolitical events.

HCI enables EPI to optimize storage and compute resources, supporting gradual capacity upgrades while mitigating capital expenditure pressures. Its shared resources also strengthen disaster recovery capabilities, ensuring sufficient computational power and flexibility during emergencies.

In terms of physical hardware, EPI adheres to asset lifecycle guidelines, as outlined in a dedicated policy that is regularly reviewed. Table 4-15 summarizes the lifecycles of the hardware units commonly deployed by EPI.

Table 4-15: Hardware Lifecycle Policy Highlights

Hardware	Equipment Type	Lifecycle

Personal Computers	Laptop	4 Years
Mobile Devices	Cell Phone / Tablets	2-3 Years
Compute & Storage	Hyperconverged Infrastructure	5 Years
Network Equipment	Firewalls/Switches/Access Points	5 Years
Office Accessories	Various	7-10 Years

4.7.3 Software Asset Management

EPI adopts a proactive software asset management strategy that ensures applications, including the Microsoft Office 365 suite, are regularly updated to stay current with the latest features, security patches, and compliance requirements. The focus is on maximizing the full potential of existing software, exploring all functionalities and efficiencies before considering new software solutions. This approach prioritizes cost efficiency and operational stability while ensuring the organization remains compliant and secure.

When updates are necessary, thorough assessments and change management processes are in place to ensure smooth transitions, minimizing disruption and optimizing staff productivity. By focusing on current tools and their potential, EPI avoids the complexity and cost of unnecessary software acquisitions while meeting evolving business needs.

For functions where standard business support functionalities cannot offer an adequate alternative to a dedicated software package (e.g., Engineering Design, GIS, or Customer Care and Billing applications), EPI attempts to utilize standard off-the-shelf technology. Functional upgrades, capability expansion, or replacement decisions are timed based on the balance of multiple factors, including:

- **Changing user requirements** articulated through a business case framework.
- **Operational performance statistics** to date (e.g., reliability, processing speed, etc.).
- **Current vendor support** and the vendor’s future upgrade roadmap.
- **Available alternative solutions** in the marketplace.

4.7.4 Forecast Period Focus Areas

Aside from routine asset lifecycle upgrades, EPI expects to focus its 2026-2030 forecast period IT expenditures on the following activity areas:

- Migrate the HCI infrastructure to a modernized solution.
- Renewal of cybersecurity support infrastructure and expansion of detection and prevention to critical operational technology assets.
- Expansion of storage capabilities to accommodate growing data requirements.
- Exploration of integrated software solutions for reporting, data analytics, and task automation and digitization.
- Explore process improvements through AI technologies.

As per its normal operating practices, EPI will evaluate the scope, timing, and sequencing of these and other potential investments in accordance with the applicable policies, and balance them with other emerging expenditure requirements, including those outside of the IT portfolio.

4.8 Facilities Asset Management Strategy

EPI's core Facilities Management priority is to maintain a safe, healthy and productive working environment for all its staff and contractors, and a safe and welcoming setting for customers and other visitors.

EPI's facilities portfolio includes operating centres in Chatham and St. Thomas, along with the land and auxiliary buildings supporting its distribution stations.

As discussed in Section 2.1.1.1 of the 2021 DSP, in 2020 EPI commenced the transition of staff from the Strathroy office to the St. Thomas facility. This transition was completed in 2021. To ensure after-hours response times can be maintained in Strathroy and Parkhill – communities further from the St. Thomas operating center – EPI continues to lease the Strathroy garage and yard as a staging facility to house selected rolling stock, equipment, and supplies.

As further detailed in the 2021 DSP, post-amalgamation, EPI embarked on a St. Thomas facilities modification project in stages starting in 2020 to accommodate both the Strathroy and St. Thomas staff in the St. Thomas operating centre. Renovations to the Customer Service, Operations, Engineering, and IT and common areas were fully completed in 2022.

Figure 34: EPI Chatham Headquarters and Operating Centre (320 Queen Street)

Figure 35: EPI St. Thomas Operating Centre (135 Edward Street)

Figure 36: The former EPI Strathroy Operating Centre, 351 Francis Street

Note: Current Strathroy Equipment Storage Facility shown above at left. Former EPI Strathroy office shown above at right.

4.8.1 Facilities Upkeep and Lifecycle Management Activities

EPI primarily engages third-party contractors for repairs and renovations within its facilities. Additionally, specialist contractors are employed to perform periodic assessments and maintenance of dedicated building systems.

To ensure the continued architectural integrity of its key building systems, EPI commissions an external architectural services firm to conduct comprehensive audits of its owned facilities every five years. In preparation for the 2026-2030 Forecast Period, EPI engaged a third-party service provider to conduct assessments of the Chatham and St. Thomas facilities to August 2024. Copies of these assessments are included in Attachment H and Attachment I, respectively.

The Chatham facility audit resulted in several key recommendations – the need to renew the building's roof and modernize the HVAC system (specifically the cooling tower infrastructure), along with other recommendations that will be evaluated further over the Forecast Period. The St. Thomas facility assessment recommended replacing some HVAC units.

4.8.2 Forecast Period Focus Areas

Over the 2026-2030 Forecast Period, EPI expects to limit the scope and scale of additional facilities expenditures to primarily general upkeep. A key project in this window involves upgrades to the Chatham office roof. Other projects which may emerge during this period include additional Chatham HVAC efficiency upgrades and roof upgrades to the St. Thomas Office.

As EPI proceeds with its area voltage conversion activities, the land supporting its distribution substation facilities will become available. As substations are decommissioned, the utility will evaluate the best course of action for each individual land parcel.

4.9 Fleet Asset Management Strategy

As previously noted, EPI serves 17 communities interspersed across an area of approximately 5,000 square kilometers. Given this distance, EPI stages its operations from facilities in two regions: northeast (served by the St. Thomas operations centre) and southwest (served by the Chatham operations centre). The driving distance and time between the northeastern-most community (Parkhill) and the southwestern-most community (Wheatley) are approximately 170 km and two hours, respectively. Accordingly, EPI currently operates a large fleet of vehicles, along with additional rolling stock units such as trailers and other miscellaneous mobile equipment units.

4.9.1 Asset Lifecycle Management

EPI's Fleet Purchasing Policy is grounded in the principles of asset lifecycle optimization and mandates the replacement of rolling stock units only upon reaching certain age or utilization thresholds. All fleet inspection and maintenance activities are performed by third-party contractors, with inspection results and maintenance cost trends regularly monitored by Fleet Management staff. Different replacement standards apply to heavy and light vehicles.

4.9.1.1 Heavy Vehicles (above 4,500 kg)

In select situations where units reach 15 years of age, but their mileage is substantially below the 300,000 km threshold, EPI may consider investing in life extension refurbishment work. However, refurbishment activities will only be undertaken if the inspection determines that the unit's life can be extended by a minimum of 5 years.

Given the materiality of expenditures associated with large vehicles, EPI's general policy is to avoid replacing more than two such units per year. If more than two heavy trucks are eligible for replacement in a given year, the utility will prioritize replacing the units with the higher mileage reading.

4.9.1.2 Light Vehicles (below 4,500 kg)

Light gasoline and alternatively fueled vehicles (pickup trucks, vans, cars) are eligible for replacement when their recorded mileage exceeds 200,000 km and/or their age exceeds 10 years in service. As with heavy vehicles, a lifecycle extension beyond 10 years of service is feasible if the unit in question is deemed capable of remaining in operation for another 3 years.

4.9.1.3 Other Equipment

EPI does not assign specific age or utilization thresholds for its fleet of purpose-specific trailers and other equipment, such as warehouse forklifts, vegetation management tools, or mobile transformer/substation units. Instead, the utility identifies units for replacement on a case-by-case basis based on individual condition assessments. As a result, many of these units have been in service since the 1990s, with several units' service lives dating back to the 1970s.

To manage overall fleet costs, EPI rents or contracts out work involving special and infrequently used equipment, such as hydro vacuum trucks or directional drilling equipment.

4.9.2 Benchmarking its Fleet Lifecycle Management Policies

To ensure that its fleet management policies are consistent with its peers, EPI analyzed publicly available rate application evidence from several Ontario utilities. Through this limited-scope verification exercise, EPI confirmed that its fleet lifecycle age thresholds are within the typical range for other utilities, which amounts to 6-10 years for lighter vehicles and 14-19 years for different types of heavy-duty vehicles.

4.9.3 Operating Costs Optimization

EPI optimizes operating costs by minimizing spare inventory and leveraging contractors for maintenance and parts procurement.

To manage its working capital costs, EPI maintains a minimum of spare inventory on-site, purchasing all necessary spares through its maintenance contractors as the need arises. EPI enhances business continuity by sourcing 50% of the Chatham fleet's fuel from an onsite gas facility supplied by wholesalers, with the remaining 50% purchased from local gas stations. The St. Thomas fleet fuels entirely at local gas stations.

Vehicle pooling further enhances cost-efficiency, providing a shared resource for staff attending work sites or stakeholder meetings. Starting in 2020, these pool vehicles were temporarily repurposed for operational use to facilitate separate vehicles for operational field staff during the pandemic. This strategy was complemented by the temporary rental of additional vehicles, which ended in September 2021. These vehicles have since resumed pool use. This flexibility exemplifies EPI's adaptive fleet management approach.

To address vehicle utilization disparities across its two operating centres, EPI considers and employs vehicle rotation. This strategy levels mileage and wear across the fleet, particularly in the Southwest region served by the Chatham operational centre, where distances between communities are greater.

4.9.4 Forecast Period Focus Areas

Looking ahead, EPI aims to maintain a stable capital cost profile aligned with historical unit replacement volumes and expenditures. This stability will be balanced against market conditions, such as rising vehicle and equipment costs observed during the Historical Period. The focus remains on ensuring the fleet is well-positioned to meet operational demands while controlling costs.

By adhering to these principles and practices, EPI ensures its fleet strategy supports reliable and cost-effective service delivery, while adapting to evolving operational needs and market dynamics. The utility's proactive approach to fleet management reflects its commitment to maintaining operational excellence and fiscal responsibility.

5 CAPITAL EXPENDITURE PLAN (5.4)

This section describes EPI's five-year capital expenditure plan over the 2026-2030 Forecast Period, including the overview of its plan and the capital expenditure planning process, an assessment of the utility's capability to connect new load and renewable generation, and a comparative analysis of past spend.

5.1 CAPITAL EXPENDITURE SUMMARY (5.4.1)

EPI's DSP outlines a comprehensive system investment program built on decisions made during its AM and Capital planning processes. To provide clarity and structure, functionally similar investment undertakings targeting the same types of outcomes are grouped into programs. This program-based approach enables a clear presentation of planned investment allocations, with detailed justifications focusing on areas where EPI has a higher degree of spending discretion. In addition to the Program-level narratives, individual project narratives for planned Year 1 (2026 Test Year) projects that exceed the materiality threshold of $195,000 are available in Attachment J. This materiality threshold is calculated based on 0.5% of EPI's proposed 2026 Distribution Revenue Requirement of $39.5M (see Exhibit 1, Section 1.5.8).

The Capital Expenditure Summary in Table 5-1 presents a ten-year snapshot of EPI's capital expenditures, encompassing five historical years and five forecast years. Projects are categorized into one of four investment categories, as outlined in the OEB's Chapter 5 Filing Requirements: System Access, System Renewal, System Service, and General Plant. This structure ensures alignment with regulatory requirements and facilitates an accurate comparison of past and planned investments.

Table 5-1: Capital Expenditure Summary ($'000s)

CATEGORY	Historical Period ($'000s)				Bridge Year	Total 2021-2025	Forecast Period ($'000s)					Total 2026-2030
	2021	2022	2023	2024	2025		2026	2027	2028	2029	2030	
System Access	$6,867	$9,910	$5,951	$5,145	$4,559	$32,421	$4,890	$4,423	$4,552	$4,651	$4,752	$23,267
System Renewal	$7,083	$7,080	$8,350	$10,384	$9,863	$42,791	$9,656	$10,665	$10,233	$10,848	$11,320	$52,723
System Service	$1,242	$901	$1,102	$1,203	$5,226	$9,675	$2,245	$2,191	$2,480	$2,528	$2,419	$11,863
General Plant	$1,885	$2,157	$2,398	$2,647	$3,899	$12,985	$3,433	$3,034	$2,560	$2,870	$2,995	$14,892
TOTAL EXPENDITURE	$17,077	$20,048	$17,801	$19,379	$23,548	$97,872	$20,224	$20,313	$19,825	$20,897	$21,486	$102,746
Capital Contributions	-$2,842	-$5,888	-$3,068	-$2,071	-$1,545	-$15,414	-$1,671	-$1,699	-$1,749	-$1,783	-$1,819	-$8,721
NET CAPITAL EXPENDITURES	**$14,235**	**$14,159**	**$14,733**	**$17,308**	**$22,003**	**$82,458**	**$18,553**	**$18,614**	**$18,076**	**$19,114**	**$19,668**	**$94,024**
System O&M	$4,628	$5,287	$5,567	$6,007	$6,404	$27,894	$6,874	$7,080	$7,292	$7,511	$7,736	$36,493

Note: The table above reflects the reclassifications of certain program types occurring in the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

To enhance the alignment of project drivers with asset needs, EPI has updated its project structure in this DSP. A refinement is the consolidation of 28 projects from the previous DSP into 23 projects in the current Plan, as shown in Table 5-2. This mapping demonstrates the utility's ongoing effort to streamline project categorizations and improve the relevance of its investment approach.

Table 5-2: EPI Project Mapping for Comparison with Previous DSP

Line No.	2026 DSP Project Name	2021 DSP Project Name
System Access		
1	Contributed Capital	Contributed Capital
2	Customer Conns: Commercial & Industrial	Customer Conns: Commercial & Industrial
		Commercial and Industrial Rebuild
3	Customer Conns: Residential & Subdivision	Customer Conns: Residential & Subdivision
4	Engineering Support Capital	Engineering Support Capital
5	Miscellaneous System Access	Delta - Wye Service Conversions
		Miscellaneous System Access
6	Third Party Attachments	Third Party Attachments
System Renewal		
7	Critical Defect Replacements	Critical Defect Replacements
8	Emergency Response	Emergency Response
9	Metering Renewal	Metering Renewal
		Metering Upgrades
10	Miscellaneous System Renewal	Miscellaneous System Renewal
11	Operation Support Capital	Operation Support Capital
12	Pole Replacement	Pole Replacement
13	Transformer Replacement	Transformer Replacement
14	Voltage Conversion	Voltage Conversion
System Service		
15	Miscellaneous System Service	Miscellaneous System Service
		System Reinforcement
16	System Modernization and Planning	System Automation
		System Modernization and Planning
17	Capacity Enhancements	Edgeware Capacity Enhancements
General Plant		
18	Building	Building
19	IT Hardware	IT Hardware
20	IT Software	IT Software
21	Miscellaneous General Plant	Miscellaneous General Plant

22	Rolling Stock	Rolling Stock
23	Tools	Tools

Table 5-3 presents the individual capital allocated to four investment categories based on their primary trigger or driver. The categorization highlights the strategic importance of each investment type in maintaining and modernizing the distribution system while addressing growth, customer needs, and regulatory obligations. These planned expenditures over the forecast period prioritize addressing aging infrastructure, voltage conversion efforts, and grid modernization ensuring the utility can maintain system reliability and meet evolving customer needs.

Table 5-3: DSP Capital Expenditure Summary by Project Drivers ('000s)

Category	Driver	Representative Programs & Projects	Historical Period				Bridge Year	Forecast Period				
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System Access	Customer Requests	Customer Conns: Commercial & Industrial	$1,622	$2,025	$1,845	$1,756	$1,402	$1,437	$1,477	$1,520	$1,557	$1,595
		Customer Conns: Residential & Subdivision	$2,894	$5,920	$2,736	$1,555	$1,802	$1,903	$1,953	$2,009	$2,040	$2,073
	Third Party Infrastructure Requirements	Third Party Attachments	$1,076	$678	$331	$17	$112	$134	$118	$122	$125	$129
	Mandate Service Obligations	Engineering Support Capital	$916	$958	$969	$978	$840	$700	$721	$742	$765	$788
		Miscellaneous System Access	$358	$328	$69	$839	$404	$716	$154	$159	$163	$168
	Contributed Capital		-$2,842	-$5,888	-$3,068	-$2,071	-$1,545	-$1,671	-$1,699	-$1,749	-$1,783	-$1,819
	Subtotal		**$4,025**	**$4,022**	**$2,883**	**$3,074**	**$3,014**	**$3,219**	**$2,723**	**$2,803**	**$2,867**	**$2,933**
System Renewal	Functional Obsolescence, Substandard Performance & Failure Risk	Voltage Conversion	$2,136	$2,387	$2,826	$3,575	$4,385	$3,555	$4,396	$4,300	$4,933	$5,255
	Failure & Failure Risk	Transformer Replacement	$698	$343	$670	$893	$185	$199	$204	$210	$215	$221
		Pole Replacement	$765	$675	$441	$853	$562	$589	$604	$621	$632	$643
		Critical Defect Replacements	$215	$387	$280	$499	$122	$312	$321	$330	$339	$347
	Functional Obsolescence	Metering Renewal	$1,358	$1,452	$1,532	$2,489	$2,658	$2,931	$3,006	$2,576	$2,478	$2,546
	System Capital Investment Support	Operation Support Capital	$1,061	$921	$1,071	$912	$968	$1,037	$1,072	$1,104	$1,137	$1,171
		Emergency Response	$850	$767	$1,315	$1,063	$807	$856	$879	$905	$921	$937
		Miscellaneous System Renewal	$1	$148	$214	$100	$176	$179	$183	$188	$194	$200
	Subtotal		**$7,083**	**$7,080**	**$8,350**	**$10,384**	**$9,863**	**$9,656**	**$10,665**	**$10,233**	**$10,848**	**$11,320**
System Service	System Reliability & Efficiency	System Modernization and Planning	$631	$690	$982	$906	$1,244	$1,372	$1,410	$1,449	$1,502	$1,381
		Capacity Enhancements	$0	$0	$0	$108	$3,900	$708	$673	$921	$914	$925
		Miscellaneous System Service	$612	$211	$120	$189	$82	$166	$108	$110	$112	$113
	Subtotal		**$1,242**	**$901**	**$1,102**	**$1,203**	**$5,226**	**$2,245**	**$2,191**	**$2,480**	**$2,528**	**$2,419**
General Plant	System Capital Investment Support	Rolling Stock	$859	$856	$1,332	$1,093	$1,317	$957	$1,195	$894	$1,240	$970
		Tools	$122	$108	$99	$89	$88	$119	$199	$102	$105	$108
	Non-System Physical Plant	IT Hardware	$217	$203	$210	$333	$260	$218	$210	$343	$284	$293
		IT Software	$324	$542	$530	$493	$619	$1,072	$535	$504	$590	$608
		Miscellaneous General Plant	$128	$201	$2	$114	$168	$164	$104	$120	$88	$161
		Building	$234	$247	$225	$525	$1,447	$903	$791	$597	$563	$855
	Subtotal		**$1,885**	**$2,157**	**$2,398**	**$2,647**	**$3,899**	**$3,433**	**$3,034**	**$2,560**	**$2,870**	**$2,995**
Grand Total			**$14,235**	**$14,159**	**$14,733**	**$17,308**	**$22,003**	**$18,553**	**$18,614**	**$18,076**	**$19,114**	**$19,668**

Note: The table above reflects the reclassifications of certain program types occurring the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

Table 5-4 provides system O&M summary for Historical and Forecast Periods.

Table 5-4: O&M Spending Summary ('000s)

Description	Historical Period				Bridge Year	Forecast Period				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M	$4,628	$5,287	$5,567	$6,007	$6,404	$6,874	$7,080	$7,292	$7,511	$7,736

Section 0 provides a summary of all capital projects for the years 2021 through the Bridge Year 2025 and discusses annual variances. A summary of all capital expenditures in the planned budgets for the Forecast Period years 2026 through 2030 are shown in Section 5.1.2. A comparison of capital expenditures for the Forecast Period vs the Historical Period is presented in Section 5.1.3. Potential Impact of capital expenditures in the Forecast Period on O&M spending is discussed in Section 5.1.5.

The proposed budgets are segmented into annual work programs. No expenditures for non-distribution activities are included in any of the capital budgets presented in this DSP.

OEB Appendices 2-AA and 2-AB have been completed and are included with EPI's COS Application as a standalone excel document (EPI_2026_Filing_Requirements_Chapter2_Appendices_1.0_2025082), offering additional insights and numerical breakdowns of EPI's capital investment plan.

Historical Period Plan vs. Actual (5.4.1a)

Table 5-5 below summarizes EPI's capital expenditures for the Historical Period (2021–2025). Overall, the Historical Period and the forecasted 2025 Bridge Year capital expenditures are higher than forecasted in the 2021 DSP. The primary drivers for this variance include:

- Customer growth: Significantly higher than anticipated growth in 2021 and 2022 in residential subdivision developments and the commercial and industrial sector, as well as new fiber infrastructure developments in the telecommunication sector, resulting in increased costs for third-party attachments.
- Inflationary pressures: Supply chain disruptions have led to significantly higher inflation in recent years compared to the historical average. While inflation remained relatively stable and modest through much of the past three decades, the period from 2021 to 2023 experienced a sharp and sustained increase, with 2022 reaching the highest rate in the last forty years. These elevated inflationary conditions have increased the costs of goods, materials, and contracted services, which in turn have directly affected EPI's cost structure. See Figure 2.
- Limited Meter Life Extension: Approximately 5,000 meters tested poorly during 2024 seal sampling testing, receiving a 2-year, non-renewable life extension vs. the 6-year renewable extension sought. See Section 5.1.2.2.4 and Attachment J "Metering Renewal" for more details. To pace spending and ensure adequate inventory and resources to lifecycle this many meters before the seal expiration, this work was began immediately upon receiving the reseal results. While these meters were just beyond their typical useful lives, Entegrus had sought to attempt to extend their service life through re-seal testing.
- Emergency restoration costs: An abnormal number of weather-related events necessitated higher emergency response expenditures. See Section 3.3.2.4 for additional details.
- Establishing new supply points: specifically the new breaker at Edgeware TS and associated feeders, as discussed at Section 3.2.6.2.

The variance analysis for the Historical Period highlights EPI's responsiveness to evolving system and customer needs, particularly in the face of unexpected growth and external challenges. While some planned projects were deferred due to resource constraints, increased emergency and automation expenditures reflect the utility's commitment to maintaining system reliability and accommodating growth.

The following sections provide a detailed analysis of annual variances by project category. Note that this table is based on 2021 DSP categorization. As described in Table 5-2 and Table 5-27, certain categories have been eliminated or reclassified in the 2026 DSP. A notable example is the "Edgeware Capacity Enhancements", which was classed in System Access in the 2021 DSP and is now otherwise classed as System Service in the 2026 DSP.

Table 5-5: 2021-2025 Historical Comparison ($'000s)

Description	Plan	Actual	Variance, %	Variance, $
2021				
System Access	$5,867	$6,867	17%	$1,000
System Renewal	$7,238	$7,075	-2%	-$163
System Service	$1,063	$1,251	18%	$188
General Plant	$1,974	$1,885	-5%	-$90
Total Expenditure	$16,142	$17,077	6%	$935
Capital Contributions	-$3,367	-$2,842	-16%	$525
Net Capital Expenditures	**$12,775**	**$14,235**	**11%**	**$1,460**
2022				
System Access	$4,308	$9,910	130%	$5,601
System Renewal	$7,669	$7,044	-8%	-$625
System Service	$968	$937	-3%	-$31
General Plant	$2,051	$2,157	5%	$106
Total Expenditure	$14,996	$20,048	34%	$5,052
Capital Contributions	-$2,300	-$5,888	156%	-$3,588
Net Capital Expenditures	**$12,696**	**$14,159**	**12%**	**$1,463**
2023				
System Access	$6,010	$5,951	-1%	-$59
System Renewal	$7,872	$8,319	6%	$447
System Service	$987	$1,134	15%	$147
General Plant	$2,088	$2,398	15%	$309
Total Expenditure	$16,957	$17,801	5%	$844
Capital Contributions	-$2,356	-$3,068	30%	-$712
Net Capital Expenditures	**$14,601**	**$14,733**	**1%**	**$132**
2024				
System Access	$3,909	$5,253	34%	$1,343
System Renewal	$9,380	$10,340	10%	$960
System Service	$1,944	$1,139	-41%	-$805
General Plant	$2,121	$2,647	25%	$526
Total Expenditure	$17,355	$19,379	12%	$2,024
Capital Contributions	-$2,413	-$2,071	-14%	$342
Net Capital Expenditures	**$14,942**	**$17,308**	**16%**	**$2,366**
2025				
System Access	$3,926	$8,459	115%	$4,533
System Renewal	$9,395	$9,730	4%	$335
System Service	$1,519	$1,459	-4%	-$60
General Plant	$2,150	$3,899	81%	$1,749
Total Expenditure	$16,991	$23,548	39%	$6,557
Capital Contributions	-$2,471	-$1,545	-37%	$926
Net Capital Expenditures	**$14,520**	**$22,003**	**52%**	**$7,483**

A key factor in the variances is the inflation experienced through the Historical Period, as described in Section 3.1.2. In addition, as described in Section 3.1.1, EPI experienced strong growth through the earlier part of the Historical Period, which drove System Access variances noted above. Detailed variance explanations for each year are presented in the sections below.

5.1.1.1 2021 Plan vs. 2021 Actual

System Access expenditures in 2021 exceeded forecasts by 61%, primarily due to unprecedented commercial and industrial growth, including large-scale developments like the Parkside Development and Bloomfield Business Park in Chatham. Third-party attachment costs also rose significantly, driven by the rapid expansion of fiber infrastructure by multiple ISPs.

System Renewal spending closely aligned with the forecast, with a minor overall variance of -2%. However, specific projects, such as Emergency Response, saw a sharp increase due to a state of emergency event in the community of Wheatley caused by a gas-related explosion[4]. The downtown core and related infrastructure sustained significant damage. The state of emergency required EPI, in addition to redesigning and rebuilding assets damaged during the explosion, to incur significant costs associated with the isolation and reconnection of customers within the evacuation zones where the presence of gas was detected. Conversely, Voltage Conversion expenditures were below budget as certain projects were deferred to 2022 due to System Access-driven budget constraints.

System Service spending exceeded the forecast by 18%. The variances included increased expenditures for system automation projects. A major driver of this variance included establishing an additional river crossing in the community of Chatham which ran over budget due to challenges with the directional drilling and unanticipated increases in material cost. This project represents half of the variance amount.

General Plant expenditures showed a 5% variance below plan, driven by minor savings in Miscellaneous General Plant due to less renovations being required at the Blenheim East DS yard than originally expected.

5.1.1.1.1 System Access

Table 5-6: 2021 System Access by Project ($'000s)

Line No.	Projects	2021 Actual	2021 Plan	Variance	% Variance	Cause of Variance
1	Commercial and Industrial Rebuild	$482	$327	$156	48%	Variance is below materiality threshold.

[4] https://www.chatham-kent.ca/localgovernment/News/pages/Emergency%20Officially%20Declared%20Over%20in%20Wheatley.aspx

2	Contributed Capital	-$2,842	-$3,367	$525	-16%	Impacted by variances in lines 3 and 4 of this table
3	Customer Conns: Commercial & Industrial	$1,140	$106	$1,034	978%	Higher than forecasted Commercial and Industrial growth specifically the Parkside Development and the Bloomfield Business Park in Chatham.
4	Customer Conns: Residential & Subdivision	$2,894	$3,753	-$859	-23%	Lower than forecasted Residential and Subdivision growth.
5	Delta - Wye Service Conversions	$152	$253	-$101	-40%	Variance is below materiality threshold.
6	Edgeware Capacity Enhancements	$0	$0	$0	0%	No variance.
7	Engineering Support Capital	$916	$765	$151	20%	Variance is below materiality threshold.
8	Miscellaneous System Access	$206	$77	$129	167%	Variance is below materiality threshold.
9	Third Party Attachments	$1,076	$587	$490	84%	An increase in this category due to multiple ISPs rapidly expanding their fibre infrastructure. EPI did not fully receive notice on some of these expansions prior to 2021, and therefore did not fully anticipate this rapid increase in attachments.
10	**Total System Access**	**$4,025**	**$2,499**	**$1,525**	**61%**	

5.1.1.1.2 System Renewal

Table 5-7: 2021 System Renewal by Project ($'000s)

Line No.	Projects	2021 Actual	2021 Plan	Variance	% Variance	Cause of Variance
1	Critical Defect Replacements	$215	$322	-$108	-33%	Variance is below materiality threshold.
2	Emergency Response	$850	$457	$393	86%	Higher expenditure is primarily due to EPI's response to the gas explosion in Wheatley, which included redesigning and rebuilding assets damaged during the event.
3	Metering Renewal	$1,350	$1,394	-$45	-3%	Variance is below materiality threshold.
4	Miscellaneous System Renewal	$1	$146	-$145	-99%	Variance is below materiality threshold.
5	Operation Support Capital	$1,061	$776	$285	37%	The digital mapping project was originally anticipated to end in 2020 and ultimately extended into 2021. This was a significant project and involved experience field staff inspecting all assets and assisting with the upload of the new information into an enhanced GIS system which supported real time visualization of the distribution system.

6	Pole Replacement	$765	$506	$259	51%	Evolving pandemic work practices provided the opportunity to Increase the number of targeted planned pole replacements this year.
7	Transformer Replacement	$698	$436	$261	60%	Global supply chain and lead time challenges resulted in the ordering of extra transformers to ensure access to supply.
8	Voltage Conversion	$2,136	$3,201	-$1,065	-33%	Due to overall budget constraints, driven by System Access demand, all or portions of three Voltage Conversion projects were postponed to 2022.
10	**Total System Renewal**	**$7,075**	**$7,238**	**-$163**	**-2%**	

5.1.1.1.3 System Service

Table 5-8: 2021 System Service by Project ($'000s)

Line No.	Projects	2021 Actual	2021 Plan	Variance	% Variance	Cause of Variance
1	Metering Upgrades	$9	$65	-$56	-87%	Variance is below materiality threshold.
2	Miscellaneous System Service	$165	$102	$62	61%	Variance is below materiality threshold.
3	System Automation	$178	$110	$68	62%	Variance is below materiality threshold.
4	System Modernization and Planning	$452	$436	$16	4%	Variance is below materiality threshold.
5	System Reinforcement	$447	$350	$97	28%	Variance is below materiality threshold.
6	**Total System Service**	**$1,251**	**$1,063**	**$188**	**18%**	

5.1.1.1.4 General Plant

Table 5-9: 2021 General Plant Projects ($'000s)

Line No.	Projects	2021 Actual	2021 Plan	Variance	% Variance	Cause of Variance
1	Building	$234	$176	$58	33%	Variance is below materiality threshold.
2	IT Hardware	$217	$160	$57	36%	Variance is below materiality threshold.
3	IT Software	$324	$320	$4	1%	Variance is below materiality threshold.
4	Miscellaneous General Plant	$128	$305	-$177	-58%	Less renovations were required at the Blenheim East Distribution Station (DS) yard than originally expected.

5	Rolling Stock	$859	$805	$54	7%	Variance is below materiality threshold.
6	Tools	$122	$209	-$87	-42%	Variance is below materiality threshold.
7	**Total General Plant**	**$1,885**	**$1,974**	**-$90**	**-5%**	

5.1.1.2 2022 Plan vs. 2022 Actual

In 2022, System Access expenditures were 100% higher than forecasted, reflecting strong residential and commercial growth across multiple communities, as well as the impact of inflationary increases in material and contractor costs. Multiple ISP's continued fiber expansion, which drove higher-than-expected third-party attachment costs.

System Renewal expenditures fell 8% below budget, largely due to resource reallocation toward customer-driven System Access projects. However, emergency response costs spiked, driven by severe storms and wind events throughout the year.

System Service projects remained consistent with forecasts with minor variations driven by scheduling conflicts.

General Plant spending exceeded the forecast by 5%, driven by higher investment related to Enterprise Resource Planning ("ERP") system discovery process and Customer Information System ("CIS") upgrades, as well as additional software costs. The ERP discovery phase led to system launch in 2024, modernizing core business applications by replacing the existing Financial Information System ("FIS") and introduced an integrated Human Resources Information System ("HRIS") and payroll module to support evolving operational and technological requirements.

5.1.1.2.1 System Access

Table 5-10: 2022 System Access Projects ($'000s)

Line No.	Projects	2022 Actual	2022 Plan	Variance	% Variance	Cause of Variance
1	Commercial and Industrial Rebuild	$729	$333	$396	119%	Higher than forecasted Commercial and Industrial growth.
2	Contributed Capital	-$5,888	-$2,300	-$3,588	156%	Impacted by variances in lines 1, 3 and 4 of this table.
3	Customer Conns: Commercial & Industrial	$1,296	$108	$1,189	1102%	Higher than forecasted Commercial and Industrial growth specifically the Parkside Development and the Bloomfield Business Park in Chatham as well as the Dennis Highbury Industrial Park in St Thomas.

4	Customer Conns: Residential & Subdivision	$5,920	$2,562	$3,357	131%	Higher than forecasted Residential and Subdivision growth including multiple new subdivisions in Chatham, St Thomas and Blenheim. Also, significant increase in material and contractor costs due to inflation.
5	Delta - Wye Service Conversions	$231	$100	$131	131%	Variance is below materiality threshold.
6	Edgeware Capacity Enhancements	$0	$0	$0	-	No variance.
7	Engineering Support Capital	$958	$780	$178	23%	Variance is below materiality threshold
8	Miscellaneous System Access	$98	$79	$19	24%	Variance is below materiality threshold.
9	Third Party Attachments	$678	$346	$332	96%	An increase in this category due to a local telecommunications companies (ISPs) continuing to rapidly expand their fibre infrastructure. Prior to 2021, EPI had not worked with one of these ISPs regarding FTTH connections and therefore did not anticipate this increase in attachments.
10	**Total System Access**	**$4,022**	**$2,008**	**$2,013**	**100%**	

5.1.1.2.2 System Renewal

Table 5-11: 2022 System Renewal Projects ($'000s)

Line No.	Projects	2022 Actual	2022 Plan	Variance	% Variance	Cause of Variance
1	Critical Defect Replacements	$387	$375	$12	3%	Variance is below materiality threshold.
2	Emergency Response	$767	$466	$301	65%	Higher expenditure mainly associated with frequent and severe storms throughout the year, including two major windstorms.
3	Metering Renewal	$1,417	$1,556	-$140	-9%	Variance is below materiality threshold.
4	Miscellaneous System Renewal	$148	$149	-$1	-1%	Variance is below materiality threshold.
5	Operation Support Capital	$921	$791	$129	16%	Variance is below materiality threshold.
6	Pole Replacement	$675	$586	$89	15%	Variance is below materiality threshold.
7	Transformer Replacement	$343	$445	-$102	-23%	Variance is below materiality threshold.
8	Voltage Conversion	$2,387	$3,301	-$914	-28%	Resources were allocated to customer driven work in System Access in 2022 and some Voltage Conversion projects were postponed to 2023
10	**Total System Renewal**	**$7,044**	**$7,669**	**-$625**	**-8%**	

5.1.1.2.3 System Service

Table 5-12: 2022 System Service Projects ($'000s)

Line No.	Projects	2022 Actual	2022 Plan	Variance	% Variance	Cause of Variance
1	Metering Upgrades	$36	$66	-$31	-46%	Variance is below materiality threshold.
2	Miscellaneous System Service	$0	$94	-$94	-100%	Variance is below materiality threshold.
3	System Automation	$56	$142	-$86	-61%	Variance is below materiality threshold.
4	System Modernization and Planning	$635	$537	$98	18%	Variance is below materiality threshold.
5	System Reinforcement	$211	$128	$83	65%	Variance is below materiality threshold.
6	**Total System Service**	**$937**	**$968**	**-$31**	**-3%**	

5.1.1.2.4 General Plant

Table 5-13: 2022 General Plant Projects ($'000s)

Line No.	Projects	2022 Actual	2022 Plan	Variance	% Variance	Cause of Variance
1	Building	$247	$199	$48	24%	Variance is below materiality threshold.
2	IT Hardware	$203	$235	-$32	-14%	Variance is below materiality threshold.
3	IT Software	$542	$315	$227	72%	Additional expenditures to expand and update Customer Service's mobile workforce management system to include more users and enhanced functionality. Also includes Enterprise Resource Planning (ERP) discovery phase.
4	Miscellaneous General Plant	$201	$247	-$46	-19%	Variance is below materiality threshold.
5	Rolling Stock	$856	$841	$15	2%	Variance is below materiality threshold.
6	Tools	$108	$213	-$105	-49%	Variance is below materiality threshold.
7	**Total General Plant**	**$2,157**	**$2,051**	**$106**	**5%**	

5.1.1.3 2023 Plan vs. 2023 Actual

System Access expenditures for 2023 were 21% below forecast. As described in Section 3.2.6.2, the Edgeware TS expansion was initially planned for 2023 and limitations on available capacity at the station resulted in this investment being deferred to 2025. This reduction was partially offset by strong commercial and industrial growth, which continued to drive costs.

System Renewal spending closely aligned with the forecast. Emergency response costs remained high due to three significant weather events, including a tornado in Chatham.

System Service expenditures exceeded forecasts by 15%. This variance was primarily driven by increase spending on automation projects, including the installation of additional smart switches aimed at improving system reliability and fault isolation.

In addition to EPI's planned system segmentation project on the 5M4 feeder in Chatham, two unplanned but critical expenditures contributed to the variance. The first was an installation of a recloser on the 5M8 feeder in Chatham. This project was in response to power quality issues experienced by a major industrial customer. Following an in-depth engineering assessment, EPI determined that installing a reclosing device on Bloomfield Road would provide the most effective solution. This installation allows for isolation of faults either within the Bloomfield Business Park or along the feeder, thereby minimizing outage impacts and improving overall service quality.

The second unplanned investment involved the relocation of existing reclosers in Wheatley. These devices were moved from within the station yard to a more accessible location outside the yard in response to a safety concern.

General Plant spending was 15% above budget, primarily due to early delivery of a Radial Boom Derrick Truck and additional software costs for modernizing EPI's GIS system. The upgrade enhances scalability, reliability, and mobile support, making map data more accessible in the formats needed to support the utility now and in the future.

5.1.1.3.1 System Access

Table 5-14: 2023 System Access Projects ($'000s)

Line No.	Projects	2023 Actual	2023 Plan	Variance	% Variance	Cause of Variance
1	Commercial and Industrial Rebuild	$787	$340	$447	132%	Higher than forecasted Commercial and Industrial growth.
2	Contributed Capital	-$3,068	-$2,356	-$712	30%	Impacted by variances in lines 1 and 3 of this table.
3	Customer Conns: Commercial & Industrial	$1,058	$110	$948	861%	Higher than forecasted Commercial and Industrial growth.
4	Customer Conns: Residential & Subdivision	$2,736	$2,604	$132	5%	Variance is below materiality threshold.
5	Delta - Wye Service Conversions	$30	$80	-$50	-63%	Variance is below materiality threshold.

6	Edgeware Capacity Enhancements	$0	$1,700	-$1,700	-100%	The Edgeware TS capacity enhancement was deferred until 2023. See Section 3.2.6.1.
7	Engineering Support Capital	$969	$796	$174	22%	Variance is below materiality threshold.
8	Miscellaneous System Access	$40	$81	-$41	-51%	Variance is below materiality threshold.
9	Third Party Attachments	$331	$300	$31	10%	Variance is below materiality threshold.
10	**Total System Access**	**$2,883**	**$3,654**	**-$771**	**-21%**	

5.1.1.3.2 System Renewal

Table 5-15: 2023 System Renewal Projects ($'000s)

Line No.	Projects	2023 Actual	2023 Plan	Variance	% Variance	Cause of Variance
1	Critical Defect Replacements	$280	$383	-$103	-27%	Variance is below materiality threshold.
2	Emergency Response	$1,315	$475	$840	177%	Higher expenditure mainly associated with frequent and severe storms throughout the year. Most costs in this category are associated to the 4 Major Event Days that occurred in 2023, as described at Section 3.3.2.2.
3	Metering Renewal	$1,501	$1,587	-$87	-5%	Variance is below materiality threshold.
4	Miscellaneous System Renewal	$214	$152	$62	41%	Variance is below materiality threshold.
5	Operation Support Capital	$1,071	$807	$264	33%	Includes incremental costs for additional supervisory resources to provide mentorship and construction oversight to Operations Department staff.
6	Pole Replacement	$441	$597	-$156	-26%	Variance is below materiality threshold.
7	Transformer Replacement	$670	$428	$242	57%	The delivery of additional transformers ordered in 2022 was delayed due to global supply chain and lead time challenges and this transformer inventory arrived in 2023.
8	Voltage Conversion	$2,826	$3,443	-$617	-18%	Significant resources were allocated to Emergency Response in 2023 due to the 4 Major Event Days, resulting in the deferral of some Voltage Conversion projects to 2024.
10	**Total System Renewal**	**$8,319**	**$7,872**	**$447**	**6%**	

5.1.1.3.3 System Service

Table 5-16: 2023 System Service Projects ($'000s)

Line No.	Projects	2023 Actual	2023 Plan	Variance	% Variance	Cause of Variance
1	Metering Upgrades	$31	$68	-$36	-54%	Variance is below materiality threshold.
2	Miscellaneous System Service	$0	$96	-$96	-100%	Variance is below materiality threshold.
3	System Automation	$309	$145	$164	113%	Variance is below materiality threshold.
4	System Modernization and Planning	$673	$548	$126	23%	Variance is below materiality threshold.
5	System Reinforcement	$120	$131	-$10	-8%	Variance is below materiality threshold.
6	**Total System Service**	**$1,134**	**$987**	**$147**	**15%**	

5.1.1.3.4 General Plant

Table 5-17: 2023 General Plant Projects ($'000s)

Line No.	Projects	2023 Actual	2023 Plan	Variance	% Variance	Cause of Variance
1	Building	$225	$203	$22	11%	Variance is below materiality threshold.
2	IT Hardware	$210	$240	-$30	-13%	Variance is below materiality threshold.
3	IT Software	$530	$320	$210	65%	Additional investments to modernize EPI's GIS system, which enhanced the reliability of the system itself and simplified data management when interacting with field staff.
4	Miscellaneous General Plant	$2	$200	-$198	-99%	Resources were allocated to IT Software for the GIS upgrade project.
5	Rolling Stock	$1,332	$908	$424	47%	A Radial Boom Derrick (RBD) truck was delivered in late 2023, ahead of the originally planned early 2024 timeline.
6	Tools	$99	$217	-$118	-54%	Variance is below materiality threshold.
7	**Total General Plant**	**$2,398**	**$2,088**	**$309**	**15%**	

5.1.1.4 2024 Plan vs. 2024 Actual

In 2024, System Access expenditures were 112% above forecast, primarily due to increased municipal requests for asset relocations. These were largely associated with road construction projects on Highbury Avenue, Fairview Avenue, St. Catherine Street, and Elysian Street in St. Thomas. Another key factor contributing to the overspend was sustained growth in the commercial and industrial sectors, which led to higher-than-expected demand for new connections.

System Renewal exceeded the forecast by 11%, driven in large part by increased expenditures in the Metering Renewal program. This was necessary due to poor test results from two sample groups, which required earlier-than-planned replacement of meters to meet regulatory standards. Emergency response costs were also elevated following the failure of an underground river crossing cable at Baseline Road in Wallaceburg.

System Service expenditures in 2024 were 41% below plan, primarily because of shifting capital priorities. With greater funding required in both the System Access and System Renewal categories, several automation and planning initiatives within System Service were deliberately postponed or scaled back to accommodate overall budget constraints.

General Plant spending was 25% higher than planned, mainly due to unexpected increases in the cost of decommissioning substations in St. Thomas and Chatham.

5.1.1.4.1 System Access

Table 5-18: 2024 System Access Projects ($'000s)

Line No.	Projects	2024 Actual	2024 Plan	Variance	% Variance	Cause of Variance
1	Commercial and Industrial Rebuild	$888	$347	$542	156%	Higher than forecasted Commercial and Industrial growth.
2	Contributed Capital	-$2,071	-$2,413	$342	-14%	Impacted by variances in lines 1 and 3 of this table.
3	Customer Conns: Commercial & Industrial	$868	$112	$756	673%	Higher than forecasted Commercial and Industrial growth.
4	Customer Conns: Residential & Subdivision	$1,555	$2,191	-$636	-29%	Lower than forecasted Residential growth.
5	Delta - Wye Service Conversions	$0	$60	-$60	-100%	Variance is below materiality threshold.
6	Edgeware Capacity Enhancements	$108	$0	$108	-	Variance is below materiality threshold.
7	Engineering Support Capital	$978	$812	$166	20%	Variance is below materiality threshold.
8	Miscellaneous System Access	$839	$82	$757	922%	Increase expenditure driven by municipal requests for asset relocation at Highbury Ave, Fairview Ave, St Catherine St and Elysian St in St Thomas.
9	Third Party Attachments	$17	$306	-$289	-95%	Lower than forecasted third party attachment requests.
10	**Total System Access**	**$3,182**	**$1,496**	**$1,685**	**113%**	

5.1.1.4.2 System Renewal

Table 5-19: 2024 System Renewal Projects ($'000s)

Line No.	Projects	2024 Actual	2024 Plan	Variance	% Variance	Cause of Variance
1	Critical Defect Replacements	$499	$391	$109	28%	Variance is below materiality threshold.
2	Emergency Response	$1,063	$485	$578	119%	Higher expenditure is primarily due to emergency response required to repair an underground cable at the Baseline Rd River Crossing in Wallaceburg.
3	Metering Renewal	$2,445	$1,619	$826	51%	EPI was an approved early adopter of smart meters and much of this infrastructure now exceeds its 15-year expected lifespan. Two-meter sample groups tested poorly in 2024. As per Measurement Canada testing regulations, the sample groups meter seal extensions were reduced from 6 years to 2 years, thereby accelerating metering renewal expenditures.
4	Miscellaneous System Renewal	$100	$155	-$55	-35%	Variance is below materiality threshold.
5	Operation Support Capital	$912	$823	$89	11%	Variance is below materiality threshold.
6	Pole Replacement	$853	$609	$244	40%	Increased expenditure is primarily due to increased material costs as detailed in Figure 2.
7	Transformer Replacement	$893	$436	$457	105%	Increased expenditure is primarily due to increased material costs as detailed in Figure 2.
8	Voltage Conversion	$3,575	$4,862	-$1,286	-26%	Resources were allocated to customer driven work in System Access.
10	**Total System Renewal**	**$10,340**	**$9,380**	**$960**	**10%**	

5.1.1.4.3 System Service

Table 5-20: 2024 System Service Projects ($'000s)

Line No.	Projects	2024 Actual	2024 Plan	Variance	% Variance	Cause of Variance

1	Metering Upgrades	$44	$69	-$25	-36%	Variance is below materiality threshold.
2	Miscellaneous System Service	$34	$98	-$65	-66%	Variance is below materiality threshold.
3	System Automation	$371	$1,085	-$714	-66%	Expenditures within this program were appropriately paced based on the available budget and staffing resources. In 2024, this is constrained by a System Access budget that is 112% greater than the forecast made in 2021.
4	System Modernization and Planning	$535	$559	-$24	-4%	Variance is below materiality threshold.
5	System Reinforcement	$155	$133	$22	17%	Variance is below materiality threshold.
6	**Total System Service**	**$1,139**	**$1,944**	**-$805**	**-41%**	

5.1.1.4.4 General Plant

Table 5-21: 2024 General Plant Projects ($'000s)

Line No.	Projects	2024 Actual	2024 Plan	Variance	% Variance	Cause of Variance
1	Building	$525	$207	$318	154%	Increased expenditures in this category include costs to decommission Sub 14 and Sub 15 in St Thomas and Sub 4 in Chatham. substations in Chatham and St. Thomas
2	IT Hardware	$333	$235	$98	42%	Variance is below materiality threshold.
3	IT Software	$493	$325	$168	52%	Variance is below materiality threshold.
4	Miscellaneous General Plant	$114	$207	-$94	-45%	Variance is below materiality threshold.
5	Rolling Stock	$1,093	$925	$168	18%	Variance is below materiality threshold.
6	Tools	$89	$222	-$133	-60%	Variance is below materiality threshold.
7	**Total General Plant**	**$2,647**	**$2,121**	**$526**	**25%**	

5.1.1.5 2025 Plan vs. 2025 Forecast

In 2025, System Access expenditures are forecast to exceed the 2021 DSP target by 375%, primarily due to the Edgeware TS capacity enhancement project, which was deferred from 2023 and implemented in 2025 as described in Section 3.1.2.1. Additional contributors included ongoing commercial and industrial growth initiated in late 2024, and increased municipal requests for asset relocations, particularly along Fairview Road and Centre Street in St. Thomas. Conversely, third-party attachment activity was lower than expected, as ISPs initiated fewer expansion projects in the service territory.

System Renewal spending is expected to be 4% above 2021 DSP levels, driven by metering renewal due to poor testing results in 2024. As per Measurement Canada regulations, meter seal extensions were reduced relative to expectations, prompting expedited replacement. Addressing these meters will be a multi-year project (See Appendix L “Metering Renewal” and Section 5.1.2.2.4). Emergency response expenditures also rose as EPI aligned the 2025 budget more closely with recent historical trends, including more frequent severe weather events, potentially influenced by climate change. See Section 3.3.2.4 for more details on MED experience. In contrast, fewer transformer upgrades were completed than originally budgeted, owing to the completion of pole-trans retirements in 2024 (requiring no additional such work in 2025), and the analysis to identify the transformers most at-risk of overload being in-process. See Section 3.1.3 for additional discussion details regarding at-risk transformers.

System Service expenditures are expected to fall slightly below 2021 DSP plans (-4%), as automation investments were scaled back to accommodate larger-than-anticipated System Access spending. However, modernization and planning expenditures increase, driven by the growing complexity of DERs and grid electrification requirements.

General Plant investments are expected to be 81% above 2021 DSP plans, largely due to major building upgrades, including the previously deferred replacement of the Chatham Operational Centre roof, as well as the construction of a new materials storage facility. Rolling stock costs also exceeded as the 2021 DSP due to EPI’s planned fleet replacement strategy, which included procurement of a bucket truck, a radial boom derrick, and a tension machine. IT investments were higher than planned due to upgrades to IT support infrastructure.

5.1.1.5.1 System Access

Table 5-22: 2025 System Access Projects ($’000s)

Line No.	Projects	2025 Forecast	2025 Plan	Variance	% Variance	Cause of Variance
1	Commercial and Industrial Rebuild	$582	$354	$229	65%	The 2025 budget includes increased expenditures driven by commercial and industrial requests received in Q4 2024.
2	Contributed Capital	-$1,545	-$2,471	$926	-37%	Impacted by variances in line 4 of this table.
3	Customer Conns: Commercial & Industrial	$820	$114	$705	616%	The 2025 budget includes increased expenditures driven by commercial and industrial requests received in Q4 2024.
4	Customer Conns: Residential & Subdivision	$1,802	$2,235	-$433	-19%	The 2025 budget includes decreased expenditures driven by continued tapering of residential and subdivision requests, including those received in Q4 2024.
5	Delta - Wye Service Conversions	$0	$0	$0	-	Variance is below materiality threshold.

6	Edgeware Capacity Enhancements	$3,900	$0	$3,900	-	The Edgeware TS capacity enhancement was deferred from 2023. Cost includes feeder buildout. See Section 3.2.6.1.
7	Engineering Support Capital	$840	$828	$12	2%	Variance is below materiality threshold.
8	Miscellaneous System Access	$404	$84	$320	382%	Increase expenditure driven by municipal requests for asset relocation at Fairview Rd and Center St in St Thomas.
9	Third Party Attachments	$112	$312	-$200	-64%	Consultations with telecommunication companies (ISP) operating in our service territory have depicted minimal projects planned for 2025.
10	**Total System Access**	**$6,914**	**$1,455**	**$5,459**	**375%**	

5.1.1.5.2 System Renewal

Table 5-23: 2025 System Renewal Projects ($'000s)

Line No.	Projects	2025 Forecast	2025 Plan	Variance	% Variance	Cause of Variance
1	Critical Defect Replacements	$122	$378	-$257	-68%	Based on 2024 third-party underground inspections, fewer vaults require refurbishment than historical experience.
2	Emergency Response	$807	$494	$312	63%	The 2025 Budget is based on recent historical actual expenditure levels which has been greater than planned and may be reflective of climate change.
3	Metering Renewal	$2,525	$1,632	$893	55%	EPI was an approved early adopter of smart meters and much of this infrastructure now exceeds its 15-year expected lifespan. Two meter sample groups tested poorly in 2024. As per Measurement Canada testing regulations, the sample groups meter seal extensions were reduced from 6 years to 2 years, thereby accelerating metering renewal expenditures.
4	Miscellaneous System Renewal	$176	$158	$19	12%	Variance is below materiality threshold.
5	Operation Support Capital	$968	$840	$129	15%	Variance is below materiality threshold.
6	Pole Replacement	$562	$622	-$60	-10%	Variance is below materiality threshold.

7	Transformer Replacement	$185	$445	-$260	-58%	Budget includes funds to replace padmount, polemount and submersible transformers. This has been accelerated due to a number of overloaded transformers being identified. Note: This project differs in scope from the 2021 DSP version, due to the full retirement of "pole-trans" (which were fully eliminated from the system in 2024).
8	Voltage Conversion	$4,385	$4,827	-$441	-9%	EPI will meet the Voltage Conversion goals established in the 2021 DSP and the expenditures within this program are appropriately paced based on the available budget and staffing resources.
10	**Total System Renewal**	**$9,730**	**$9,395**	**$335**	**4%**	

5.1.1.5.3 System Service

Table 5-24: 2025 System Service Projects ($'000s)

Line No.	Projects	2025 Forecast	2025 Plan	Variance	% Variance	Cause of Variance
1	Metering Upgrades	$133	$70	$63	89%	Variance is below materiality threshold.
2	Miscellaneous System Service	$82	$100	-$18	-18%	Variance is below materiality threshold.
3	System Automation	$440	$643	-$203	-32%	Expenditures within this program are paced based on the available budget and staffing resources. In 2025, this is constrained by a System Access budget that was 440% greater than the forecast made in 2021.
4	System Modernization and Planning	$804	$570	$234	41%	Includes incremental costs for additional engineering resources to support the growing complexity of distributed energy resources (DERs), electrification readiness, and evolving energy applications. These resources conduct technical analysis, system integration, and operational planning to address emerging challenges in grid modernization and compliance.
5	System Reinforcement	$0	$136	-$136	-100%	Variance is below materiality threshold.
6	**Total System Service**	**$1,459**	**$1,519**	**-$60**	**-4%**	

5.1.1.5.4 General Plant

Table 5-25: 2025 General Plant Projects ($'000s)

Line No.	Projects	2025 Forecast	2025 Plan	Variance	% Variance	Cause of Variance
1	Building	$1,447	$211	$1,236	585%	Includes the replacement of half of the Chatham Operational Centre roof in 2025, as well as the Chatham HVAC cooling tower as recommended in the third party 2024 building assessment shown at Attachment J. Also includes the construction of a Materials Storage Building adjacent to the Chatham Operational Centre to support prudent asset management and safeguard critical materials.
2	IT Hardware	$260	$255	$5	2%	Variance is below materiality threshold.
3	IT Software	$619	$310	$309	100%	Additional expenditures include Work Management System (WMS) discovery phase review, as well as an IT backup software refresh.
4	Miscellaneous General Plant	$168	$205	-$37	-18%	Variance is below materiality threshold.
5	Rolling Stock	$1,317	$943	$374	40%	As per EPI's rolling stock asset management strategy described in Section 3.9.1, this includes a single bucket truck, a radial boom derrick and a tension machine required replacement.
6	Tools	$88	$226	-$138	-61%	Variance is below materiality threshold.
7	**Total General Plant**	**$3,899**	**$2,150**	**$1,749**	**81%**	

5.1.2 Forecast Period Plan (5.4.1b)

As detailed throughout this DSP, EPI's 2026-2030 Plan emphasizes investments in System Renewal, which constitutes 54% of the planned capital expenditures. This reflects EPI's commitment to addressing aging infrastructure, and maintain reliability and system resilience. The focus on System Renewal aligns with the findings of the ACA, which identifies significant portions of the distribution system as being in "Poor" or "Very Poor" condition (see ACA included as Attachment B, at Section 4).

System Access investments, comprising 23% of the plan, are driven by customer and third-party requests for new connections and asset modifications. These projects are primarily non-discretionary and dictated by EPI's obligations as a licensed distributor.

System Service expenditures focus on system automation and capacity enhancements, targeting reliability improvements and planning for future load growth. This category represents 8% of total planned expenditures.

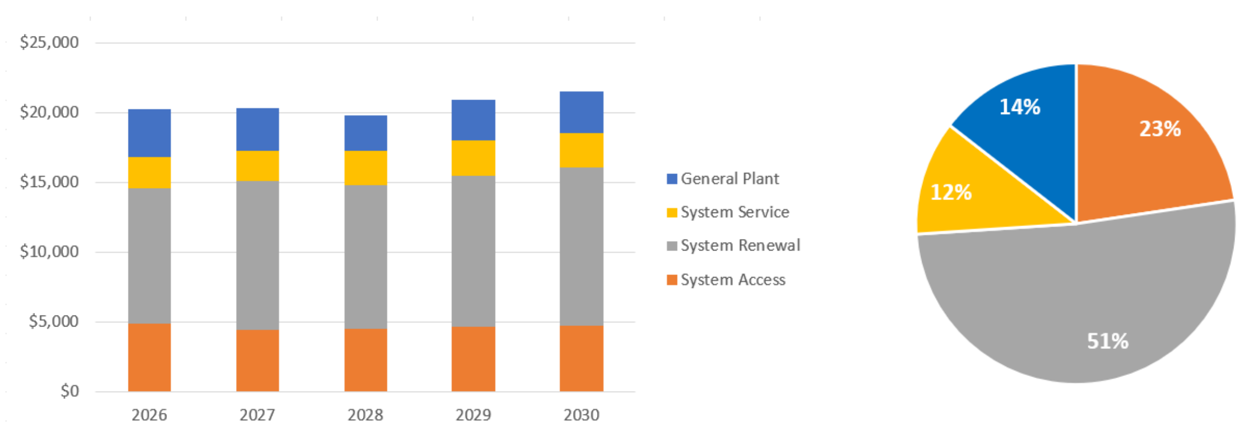
General Plant investments account for 15% of the planned expenditures, supporting critical non-distribution assets such as fleet, facilities, and IT systems to maintain efficient and safe operations across EPI's service territory.

A year-over-year inflation assumption of 3% was used through the 2026-2030 Forecast Period.

Projects spanning multiple years are capitalized as specific components enter service (i.e. become "used and useful"). Any components under construction remain in WIP until they are placed in service. Therefore, partial capitalization may occur in stages depending on the nature of the project.

The following Figure 37 summarizes the planned capital expenditures by investment category over the Forecast Period.

Figure 37: EPI Capital Expenditures 2026-2030, Gross Capital



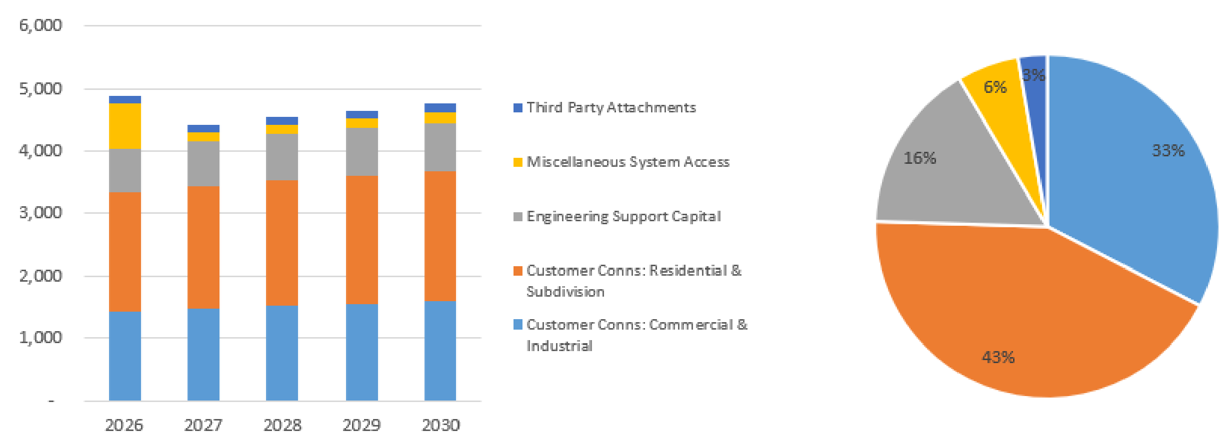
5.1.2.1 System Access

System Access expenditures are largely a function of the volume and timing of requests from existing and prospective customers, and third parties seeking modifications to EPI's assets.

Since utilities are obligated to interconnect new customers and offer the related services by the terms of their distribution licenses, most System Access work is non-discretionary in nature and timing. A challenging reality associated with investment planning work for this portfolio is the fact that specific project scopes are frequently unknown at the time of budgetary exercises, as customer connection or facilities modification requests can be submitted at any time. To account for this, typically EPI bases its forecasts for connection and service relocation-related parts of the System Access portfolio on relevant historical expenditure levels for these activities. Where specific major undertakings are known over the Forecast Period (i.e. from developer engagement activities), their impact is accounted for in the forecasts. In the event where the connection or relocation demand is tracking to exceed the budgeted amounts during a given year, EPI has historically re-allocated the necessary funds to System Access by adjusting the scope of other planned projects where it has some pacing discretion (typically the System Renewal investments).

Overall, System Access investments represent the segment of EPI's capital portfolio where there is the least discretion regarding the scope and timing of investments. Figure 38 provides a detailed breakdown and percentage distribution of EPI's planned System Access Investments.

Figure 38: 2026-2030 System Access Expenditure Plan ($'000s)



5.1.2.1.1 Customer Connections: Commercial and Industrial

5.1.2.1.1.1 Commercial and Industrial Rebuild

Aside from customer-driven requests, the costs of this program include the lifecycle-based renewal of assets serving the specific customers (e.g. overhead and underground primary feeder and transformation infrastructure). This program supports lifecycle-based renewal of infrastructure serving C&I customers. Connections above 200 kW are reviewed by EPI's Planning staff to evaluate the practicality of bypassing connection to legacy low-voltage systems. This strategy avoids premature asset obsolescence and supports EPI's long-term objective of eliminating legacy systems. While this approach may incur higher upfront costs, it ensures economic efficiency over the asset's lifespan.

5.1.2.1.1.2 Commercial and Industrial Connections

EPI prioritizes C&I connections due to their critical role in supporting local economies, as such, accommodating any requests for capacity expansion or other modifications, or preventing any avoidable power outages is a major planning and operational priority. Much of the work is driven by the existing customers' near-term requests, or by connection applications from new customers, the nature, timing and volumes of which are not readily predictable. Given this reality that the forecasting year-over-year expenditures for this category is challenging, EPI relies on past trends and ongoing engagement with existing and prospective customers to establish budgets.

5.1.2.1.2 Customer Connections: Residential & Subdivision

5.1.2.1.2.1 Residential Connections

Residential connection expenditures are driven by requests from new or existing customers for service connections, capacity upgrades, or modifications. These projects are evaluated through EPI's Conditions of Service, and work proceeds following customer acceptance of an Offer to Connect ("OTC").

In some cases, a new connection may involve as little effort as the installation of a new revenue meter onto existing equipment. Many connection requests and most modification requests involve installation or relocation of pole lines, overhead conductor or underground cable services, and deployment of the appropriately sized and located transformation equipment. Given the variability in the scope of work across the individual customer requests and the variability of requests from year to year, EPI relies on historical trends to set the budget amounts for these non-discretionary expenditures. There are no alternatives as to the timing or location of this customer driven work, given that the timelines are a function of the Distribution System Code requirements.

Where configuration alternatives are available, EPI discusses them with requesting customers and alerts them of any technical considerations or scope implications inherent in the available alternatives. In absence of customer preference otherwise, the most cost-effective solution is chosen. EPI retains the final say as to the ultimate technical configuration of the new or modified facilities.

5.1.2.1.2.2 Residential Subdivision

This program captures the costs to connect new residential subdivisions or townhouse developments and/or expand the upstream system capacity to enable their connection. Unlike the individual connection requests, real estate developers act as proponents for these types of connection projects.

Prior to commencing any connection work, EPI prepares an OTC in alignment with regulatory requirements and submits it to the developer for acceptance. The OTC outlines the scope and cost of connection work, separating out the components into those that must be completed by EPI and those eligible for construction by third parties should the developer elect such an option.

EPI determines the specific amount of developer cost contributions using an economic evaluation model that factors in the type, timing and volume of connecting load and the total cost of work, to determine the portion that can reasonably be recovered in rates over the five-year economic evaluation period. EPI rebates the developers' capital contributions over a five-year timeline, or until such time as the new development is fully occupied.

There are no alternatives to completing this work, as EPI is obligated to connect new load as a part of its Distribution License conditions. While technical alternatives as to the scope and nature of the connection work may exist (e.g. overhead vs. underground service, capacity, redundancies, etc.) these are typically project- and site-specific.

5.1.2.1.3 Engineering Support Capital

This program captures the capitalized cost of engineering and design services associated with detailed preparation of design and construction packages prior to the execution of System Access projects.

Through the Historical period, EPI has expanded engineering resources in recognition of the industry's growing complexity, including new technologies like smart switches, DERs, and NWSs. These new technologies have required more engineering sophistication, including capacity studies and detailed coordination with customers, as well as with the IESO and Hydro One. EPI engineering personnel are well-versed in modern power system management, including the fundamentals of advanced engineering and design software packages (e.g., GIS, CAD), and have a solid understanding of AM as both a formal discipline and a practical way of structuring EPI's decision-making. EPI also ensures that its engineering and design personnel dedicate a portion of their time to field activities to develop a practical outlook on the implications of their decision-making.

Aside from developing and transforming higher-level planning estimates into specific design drawing and construction materials work orders, EPI's engineering and design professionals are directly involved in maintaining compliance with all relevant operational, public safety and customer service standards that EPI is subject to. As such, while directly contributing to the asset lifecycle management value chain, the expenditures captured in this program represent a key compliance risk mitigation lever.

There are no practical alternatives to performing the activities captured in the cost of this program. EPI strives to increase the overall throughput efficiency of its engineering and design work by progressively expanding its use of software solutions to manage the manual labour costs. Outsourcing to third-party contractors is a practical option for certain engineering activities, where additional temporary resources may be required due to customer-driven workload. EPI remains committed to maintaining a strong core of internal engineering specialists who are deeply familiar with local system characteristics and capable of performing a wide range of analytical tasks. At the same time, certain tasks - such as engineering layout and design – are outsourced when needed to address temporary resource constraints.

5.1.2.1.4 Miscellaneous System Access

5.1.2.1.4.1 Capital Expansion Requests

This program captures the costs of accommodating requests from third parties to relocate EPI's system assets located within or adjacent to the sites of planned infrastructure improvement or construction activities. Examples of projects that drive asset relocation requests include municipal and provincial road widening work, relocation or modification of highway ramps, reinforcement of railway bridges, or residential and commercial construction.

In accommodating the relocation work, EPI recoups the eligible portion of the project costs from the requesting customers, up to the limitations prescribed by the applicable legislative and regulatory instruments. To maximize the value of this work, EPI explores opportunities to replace, upsize or otherwise modify the assets that are being relocated, provided that their current condition or anticipated load growth make such modifications economic. Given that EPI is obligated to accommodate the relocation requests by the conditions of its Distribution License, there are no viable alternatives to conducting this work within the timeframes or locations requested.

Alternatives may exist as to the exact scope and configuration of the assets subject to relocation, such as whether the relocation work already being performed in the area justifies making adjustments to the adjacent infrastructure as well, given the costs of staging, engineering and design, and truck rolls already being incurred in the local area. However, given the variability of types and locations of requests, these scope-related alternatives can only be considered on a project-by-project basis. In addressing the potential alternatives, EPI attempts to balance the considerations of Operational Efficiency and Cost Effectiveness, thereby ensuring that the externally mandated work generates maximum incremental benefits for the broader customer base as well.

A complicating reality associated with this program is the variability from year to year in the number and size of requests from EPI's municipal shareholders and other parties. This means that capital expenditure budgeting and multi-year planning must primarily rely on past expenditure trends. Should the budgeted amounts in any given year be insufficient to accommodate the external requests, EPI reallocates the funds from other types of System Access projects, or else proactive System Renewal expenditure budgets.

In accommodating the community improvement or infrastructure enhancement projects, the Capital Expansion Request work enables broader economic benefits for the communities served by EPI and southwestern Ontario more generally.

5.1.2.1.4.2 FIT Project Support Costs

This minor budgetary item is associated with the interconnection of all types of new customer-owned generating projects (solar, load displacement, etc.) to EPI's distribution system and/or making modifications to the existing connection infrastructure. While EPI is monitoring provincial energy policy or other activities which may drive significant investment in this area, EPI currently does not anticipate any material volumes of connection requests over the Forecast Period, it does intend to undertake minor upgrades to the metering and protection infrastructure associated with some of the existing project sites.

5.1.2.1.5 Third Party Attachments

This program performed by EPI's Engineering divisions covers the cost of work associated with design, testing installation and upkeep of various devices to EPI's distribution poles when requested by third parties. In most cases, the equipment being attached to the poles are various third-party communication devices and implements required for propagation of cellular signal and/or wireline technologies. EPI recovers the costs of this work by way of customer charges negotiated with the requesting parties. There are no viable alternatives associated with this work, as EPI is required to complete such work through the conditions of its License.

5.1.2.2 System Renewal

The System Renewal portfolio represents the cornerstone of EPI's DSP, addressing critical infrastructure challenges and ensuring the long-term reliability, resilience, and efficiency of the distribution system. This portfolio is driven by the need to replace aging and deteriorated assets, proactively manage system risks, and align with evolving customer and regulatory expectations.

A significant portion of System Renewal efforts focuses on the ongoing conversion of legacy low-voltage feeder infrastructure to the modern 27.6 kV standard. This program not only addresses system reliability and capacity but also directly mitigates challenges related to outdated and inefficient infrastructure. The benefits of voltage conversion include avoided substantial capital station costs by decommissioning distribution stations, reduced line losses, enhanced weather resilience, and greater capacity to accommodate emerging grid uses such as distributed generation and electric vehicle charging.

The Voltage Conversion program is a strategic pillar of EPI's approach to managing aging infrastructure. By converting feeders and decommissioning legacy 4 kV substations, EPI avoids significant station asset rebuild costs. Beyond station assets, the program also facilitates the systematic replacement of other deteriorated distribution infrastructure and specific asset classes in relatively worse condition, such as aging concrete poles, and submersible transformers, thereby addressing multiple asset risks in a coordinated, cost-effective manner.

In addition to asset renewal through voltage conversion, EPI's System Modernization and Planning program, as described in Section 5.1.2.3.1, provide further mitigation against the impacts of infrastructure aging. In areas where system degradation continues, EPI's deployment of Distribution Automation technology allows for rapid isolation of faults, minimizing customer impacts by restoring service to the majority of customers quickly while limiting outages to smaller affected segments.

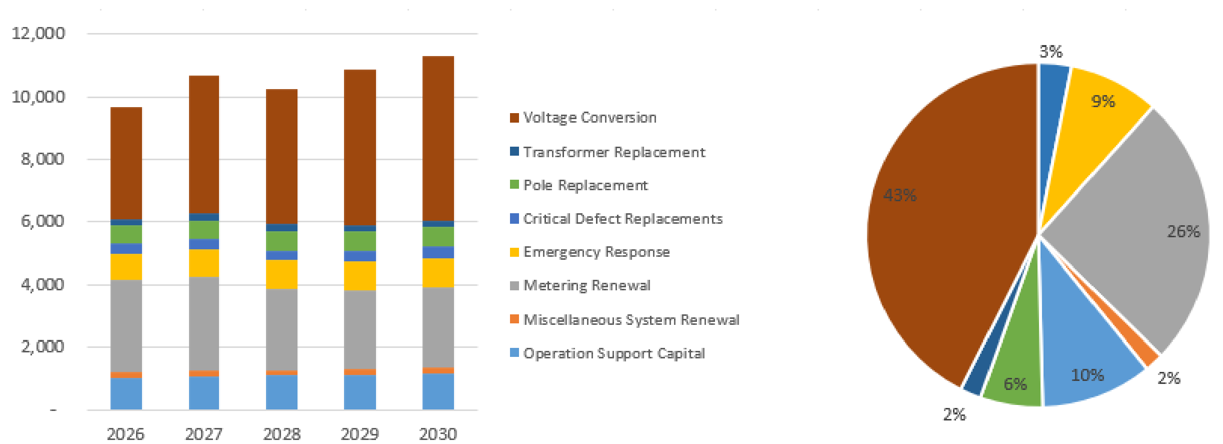
Complementing the voltage conversion initiative is the reactive replacement of end-of-life overhead and underground assets identified through routine inspections and risk-based analytics. EPI leverages its ACA and risk-based intervention planning methodologies to prioritize projects and allocate resources effectively.

Additionally, System Renewal encompasses the lifecycle replacement of AMI, including smart meters and associated data collection systems. EPI was an approved early adopter of smart meters, and a substantial portion of this infrastructure now exceeds its 15-year expected lifespan, with some batches faring poorly on re-sealing tests, or failing re-sealing tests, necessitating more immediate replacements. Given the increasing obsolescence and operational limitations of the legacy AMI systems, EPI plans a phased replacement strategy to modernize its metering infrastructure, ensuring compliance with regulatory requirements and safeguarding against cybersecurity threats.

Other key elements of the System Renewal portfolio include transformer and pole replacements, emergency response efforts, and critical defect replacements. These activities address immediate reliability and safety concerns while aligning with EPI's strategic objectives of operational excellence, customer focus, and sustainable growth.

Figure 39 below shows the planned expenditures for this category.

Figure 39: 2026-2030 System Renewal Expenditure Plan ($'000s)



It is important to note that some projects in the System Renewal category can be shifted from year to year. This flexibility has historically enabled EPI to manage unforeseen, higher-than-budgeted demands from System Access programs. The comparatively greater discretion over the scope and timing of System Renewal investments allows EPI to remain responsive to emerging priorities while maintaining its asset management commitments.

5.1.2.2.1 Voltage Conversion

EPI's legacy voltage systems have engineering limitations which render them unsuitable for ongoing use. The capacity of the system is very constrained (multiple substations worth of 4kV capacity can be served from a single 27 kV feeder), which places their renewal at odds with EPI's system modernization goals, supporting DERs (e.g. NWS, EVs, heat pumps), other more intensive electrical uses. The lower voltage is subject to greater losses, reducing overall system efficiency. Much of the infrastructure is obsolete, making ongoing sustainment increasingly difficult and legacy construction standards introduce special procedures to enable safe work.

The relatively low capacity of the system results in relatively few customers per feeder. This reduces the effectiveness of smart-grid investments by limiting the number of customers who are able to benefit from a given asset.

Migration to a 27.6 kV system mitigates these limitations.

The Voltage Conversion program is the most significant of EPI's proactive System Renewal undertakings. There are many benefits from Voltage Conversion, as discussed above and in Section 5.1.2.2. One key driver of EPI's conversion plan is the avoided costs associated with decommissioning its distribution stations rather than rebuilding them. EPI's fleet of distribution stations are nearing end-of-life, and the availability of parts for repair is dwindling. Increasingly parts must be custom made, resulting in higher costs and longer lead times. The 2026-2030 forecast period voltage conversion costs are driven by a combination of recent inflationary pressures on major materials and a slightly increased work tempo in comparison to previous decommissionings.

The cost of decommissioning a substation has two components, the decommissioning of the station itself, and the more significant cost of converting all the line infrastructure that is fed from that station. As stations have differing amounts of line and customers fed from each the total effort to decommission a station varies from station to station.

During the 2026-2030 period, Entegrus plan is to decommission 5 substations. A new metric has been added to this DSP to track the decommissioning of substations, please see Section 4.1.1.1 for additional details.

While low-voltage assets presently exist in the majority of communities served by EPI, pacing and prioritizing the specific replacement candidates is required given the constraints imposed by annual funding allocations and regional labor resource availability. To prioritize among specific projects, EPI relies on the Risk-Based approach described in Section 4.3, supplemented by the analysis of local system reliability and other analytical tools and processes comprising its AM process discussed in Section 4.1.

Overall, the majority of assets comprising EPI's low-voltage feeders are currently in Fair or Poor condition. The use of AM analytical processes enables EPI to identify the geographical and electrical areas with the highest asset risk, as represented by the probability of asset failures and the impact of failures on EPI's own costs and those incurred by the affected customers.

The pace and timing of the conversion projects are driven by the need to decommission aging substations that supply connected customers before the substation equipment itself requires replacement. More specifically, communities with only one low-voltage substation are prioritized higher due to their limited backup options and, therefore, the risk of sustained outages in the case of substation failure. While EPI's primary mitigation for this risk is conversion, EPI maintains a fleet of two mobile substations and has completed installation plans for their deployment either in response to an unplanned station failure or in support of station maintenance activities. EPI inspects its substations on a monthly basis and also periodically tests its backup mobile substations to ensure a constant state of readiness.

Conversion projects address the inherent failure risk from both the failure of the line assets themselves, as well as providing mitigation against station failure risk. Given expected timelines to finish conversion, EPI has begun a program of active asset life extension at substations where the conversion horizon is expected to exceed the remaining service life. This program includes elements such as transformer oil drying and treatment, P&C modernization, communication equipment upgrades and egress cable injection among other elements as applicable to each station. These projects offer a cost-effective way to provide enhanced monitoring of station conditions, enabling EPI to defer major station replacement costs while managing risk and maintaining reliability within the system until conversion can occur.

In conducting the voltage conversion work, EPI also improves the overall resilience of its system, as all replacement overhead lines are built to a contemporary standard that prescribes tower spans, guying (attachment) and vegetation clearances that are more conducive to withstanding inclement weather. Similarly, where voltage conversion involves replacement of underground cable, EPI places the new cable segments into rubberized or concrete ducts, to extend the equipment's service lives and simplify future replacement efforts. Aside from adding resilience, reducing losses and mitigating failure risk, voltage conversion creates additional feeder capacity on EPI's system, enabling local load growth in the areas of commercial development and residential density intensification, and creating a system more conducive to the emerging types of grid use, such as distributed generation, small-scale storage, or EV charging.

While the above-noted benefits add significant value to the projects, it is important to note that voltage conversion entails an upgrade rather than a like-for-like replacement, requiring taller poles, larger diameter cables and conductors and higher capacity transformers. This means that the overall system replacement cost is increasing, although this impact will be offset by the avoided cost from eventual decommissioning of all the step-down substations, and the resulting foregone capital replacement expenditures and ongoing OM&A cost savings.

The primary alternative to asset renewal is the deferral of work – through either postponement of any intervention activities or completion of refurbishment activities to extend the equipment's lifecycle. EPI has determined that deferral is not an economic alternative for the 2026-2030 Forecast Period, as the intervention expenditures for the conversion investments planned over the 2026-2030 timeframe are lower than the cost risk of leaving the plant for reactive renewal. Moreover, deferral of the conversion work is also suboptimal given EPI's objectives of decommissioning all its substation equipment without replacing them. To accomplish this important objective, area conversion must be completed before the substation equipment reaches its own end of life. These plans are further detailed in Attachment J – Voltage Conversion.

Asset refurbishment is not a viable option for this program, as the existing assets are generally unsuitable for higher voltage service (e.g., poles are too short to meet modern construction standards, cable insulation ratings are insufficient, etc.). For the limited amount of renewal being undertaken on 27.6 kV assets, there are some limited options for refurbishment which are evaluated on a case-by-case basis. Pole trusses can potentially be applied if appropriate, while cable injection can be considered. Cable injection is reserved for high-value cables that are difficult and expensive to replace due to the challenges associated with cable injection (system outages, failure risk, refurbishment vs. replacement costs). Some asset types, such as 27.6 kV switches, are regularly refurbished where asset condition allows.

While EPI reactively replaces individual failing components of low-voltage feeders should these occur before the scheduled area conversion work, reactive replacement is not a viable long-term strategy as it prevents EPI from accomplishing a number of the program's key objectives (most notably loss reduction, capacity increase and substation retirement). Moreover, a long-term reactive strategy is inconsistent with grid modernization objectives of preparing the grid to serve anticipated customer uses associated with electrification such as EVs, heating electrification, and DERs.

Over time, conversion is expected to reduce System O&M costs associated with emergency maintenance in response to power outages on the aged and deteriorated infrastructure. EPI also expects to realize material system O&M savings through the paced decommissioning of its substations once voltage conversion work makes them redundant. Beyond these considerations, the conversion work is not expected to generate any more material O&M savings, as EPI will continue to be required to perform cyclical line patrols and vegetation activities. However, given the current state of degradation in portions of the distribution system, and the pace of the requisite System Renewal activities planned for the 2026-2030 timeframe, EPI anticipates that any reductions in Reactive Maintenance spend will be fully offset by the Risk-Based Maintenance spend associated with patrol-defined rectification of one-off deficiencies.

5.1.2.2.2 Transformer Replacement and Pole Replacement

These programs capture the costs of replacement of the major components of EPI's distribution system – poles and transformers, with the auxiliary pole-top equipment. Unlike the voltage conversion program expenditures, this program captures the cost of smaller-scale replacement of individual units that reach end-of-life as determined by overhead system patrols or in-service failures. Supplementary to all other System Renewal work, forecasted replacement volume forecasts are a function of risk-based planning analysis that relies on the ACA results to forecast the number of annual failures, and historical information that tracks the actual failure and replacement occurrences.

Unlike the Voltage Conversion Program, which proactively targets significant groups of assets for replacement, this segment of EPI's investment portfolio is focused on reactive replacements. These are scheduled in response to work orders generated from field inspections or triggered by outage events where equipment failure renders repair unfeasible.

While some assets replaced under this program are addressed before they completely fail, the approach remains consistent with a Run-to-Fail strategy. This strategy is applied to assets identified by inspection patrols as having reached the end of their useful life and exhibiting imminent signs of failure. This differs fundamentally from proactive or predictive replacement strategies, which pre-emptively replace deteriorating equipment based on risk-based analyses without requiring visible signs of imminent failure.

Although EPI aims to minimize in-service failures that could result in outages, achieving a failure-free system would be economically unfeasible. Instead, EPI adopts a hybrid approach, combining the proactive asset replacement integral to the Voltage Conversion Program with this reactive strategy. This hybrid model strikes a balance between cost-effectiveness and reliability, ensuring that limited resources are allocated where they are most impactful.

By relying on reactive replacements for specific assets, EPI effectively extends the lifespan of its infrastructure while ensuring safety and operational integrity. However, this approach is complemented by targeted proactive measures to address critical areas where failure risks and customer impacts are highest, ensuring a resilient and adaptive network.

This program's expenditures also include the phasing out of submersible transformers and replacement of pad-mounted transformers that have reached their ends of useful lives based on inspection Work Orders or in-service failures. The volume of transformer unit replacements is forecasted using a combination of historical failures and asset management analytics tools that utilize asset demographics data and failure curve information.

Moving forward, EPI plans to test poles on a community-by-community basis to reduce travel time for testers. This approach aims to increase the number of poles tested each year without additional investment.

Remediation work associated with this program is typically performed by internal crews. When scheduling replacements identified by feeder patrol results, planners attempt to optimize the sequencing and locations to leverage any locational synergies that may be available. When assets fail in service and cause an outage, the scope and nature of replacements (if required) are a function of the event's physical location.

5.1.2.2.3 Operations Support Capital

This program captures the costs of oversight and supervision of construction activities by non-engineering personnel. Effective supervision of construction work ensures crew safety, minimizes disruptions to the surrounding areas, and ensures compliance with relevant technical standards and adherence to project budgets. Specific costs incurred year-to-year depend on individual project scopes and any unforeseen circumstances that may take place.

Construction crew supervision also plays an important role in EPI's AM process, as crew supervisors are the direct source of feedback on estimation and configuration decisions made by the engineering and design personnel. They also possess a unique practical subject matter expertise that EPI relies on when rescheduling or rescoping its short-term construction plans.

There are no practical alternatives to incurring the costs of construction work supervision, as doing so would entail non-compliance with a number of internal and external safety and labour relations policies.

5.1.2.2.4 Metering Renewal

5.1.2.2.4.1 AMI Infrastructure Renewal

EPI was an approved early adopter of smart meters and much of this infrastructure now exceeds its 15-year expected lifespan, with some batches faring poorly on re-sealing tests, or failing re-sealing tests, necessitating more immediate replacements. Over the 2026-2030 Forecast Period, approximately 35% of EPI's fleet of smart meters will have reached the end of their first re-seal period as specified by Measurement Canada, and 30% will have entered their second re-seal period. As described in Section 5.1.2.2, the paced smart meter re-seal and replacement process may require second re-sealings of some units. Management has determined that, along with the large-scale replacement of the individual metering units, it is advisable to upgrade the AMI communication infrastructure, including Network Servers, Signal Amplifiers, Network Controllers, and the Head-End System.

Key components of the current meter data communication and collection infrastructure have been in service since 2006-2007, when, after a successful pilot project, smart meter deployment commenced within EPI's service area. Since the time of the original deployment, AMI communication hardware and software offerings have become substantially more robust and efficient, enabling greater area coverage per physical asset count, increased data processing and verification efficiency, and incremental automated and/or remote troubleshooting capabilities. With a portion of its meter fleet comprised of the first generation of commercially available AMI infrastructure, a number of these benefits are not available to EPI, as incremental upgrades in specific areas of the network or elements of the core infrastructure are often not compatible with the older versions of the system's firmware. As such, the core legacy infrastructure's communication and processing capabilities are the limiting factor in deriving any incremental benefits from upgrades to individual meters or network nodes. Until the core AMI system components are upgraded to contemporary standards, they will remain the "lowest common denominator" that will limit the value gains from any smaller-scale enhancements driven by lifecycle needs or local considerations.

The status quo of EPI's legacy AMI infrastructure is further impacted by procurement challenges. Maintaining access to a supply of meters, as well as support for older legacy communications modules to ensure that equipment can continue to operate efficiently to its planned life expectancy, has proven challenging. Additionally, contracted accredited meter re-verifiers are signaling their intent to remove meter re-sealing services from their accreditation for some aged technologies still relied upon by EPI. Operating two smart-metering systems drives complexity in integration with other key business systems and requires duplication in inventory and training. Procurement work underlying the planned upgrades involves anticipated harmonization to one smart-metering system.

Given the capability enhancements inherent in the newer technology and the potential for locational work execution synergies when replacing meters concurrently with the associated infrastructure, these investments seek to ensure that EPI's AMI infrastructure is based on modern and efficient technology with a minimal physical and financial footprint, lower support requirements, and better equipped to mitigate cybersecurity and data integrity risks.

EPI notes that the timing of these investments is somewhat discretionary, to the extent that the infrastructure in question continues to meet Measurement Canada's technical requirements and the OEB's data quality standards (e.g., billing accuracy). As such, the primary alternative to the investments comprising this segment of the Metering Lifecycle Management program is deferral to future periods. However, EPI deems this alternative to be suboptimal, the increasing risk profile associated with outdated communications equipment, and synergetic opportunities to coincide the broader AMI infrastructure upgrades with the staged replacement of smart meters at the end of their re-seal periods.

Beyond the timing of the investment, there are multiple alternatives regarding technology providers, communication mediums, and specific solutions that EPI expects to evaluate in detail in the early phases of this project. EPI expects to pace the specific timing and sequencing of these investments over the 2026-2030 Forecast Period in accordance with the volumes of other types of System Access work, over which it has substantially less discretion.

5.1.2.2.4.2 Meter Re-Sealing

This segment captures the costs of compliance activities driven by a Measurement Canada requirement to verify the accuracy of retail revenue meters once they reach a certain in-service age milestone. The work involves taking a random sample of meters of a specific vintage and providing them for testing at Measurement Canada's facilities, while installing temporary meters in their place. Should the random sample pass the verification, the entire cohort represented by the particular sample is authorized to remain in service for a specified period of time.

The expenditures associated with meter re-sealing are mandatory if EPI elects to keep the meters in operation past the expiration of their original seal. It is EPI's general policy that all eligible meters undergo initial verification determination and re-sealing after the expiration of their original (post-manufacturing) seal period to extend their lifecycle as prescribed by Measurement Canada regulations. Given that re-sealing is a regulatory requirement, the only alternative is to replace the meters after the end of their original seal's expiration. EPI believes that re-sealing its meters upon expiration of their original manufacturing seal is a cost-effective approach to extend the lifecycle of its investments. Further, as described in Section 5.1.2.2, the paced smart meter re-seal and replacement process may require second re-sealings of some units.

5.1.2.2.4.3 Retail Meter Replacement

This segment captures the expenditures related to the replacement of smart meters that fail or sustain irreparable damage in service, are found to be faulty through EPI's own or Measurement Canada testing, and/or reach the expiration of their original re-seal periods. The expenditure volumes over the Forecast Period are primarily driven by a significant cohort of meters that will reach the end of their re-seal period, with a substantially smaller portion driven by in-service damage or failures and test-based rejections. While further re-sealing is a technically feasible alternative and may be required to maintain a paced smart meter replacement strategy, the risks of technological obsolescence and the increasing probability of in-service failures will require close monitoring, due to the already 15-year-old design and limited functionalities of some meter units.

5.1.2.2.5 Emergency Response

The cost of this program captures the cost of emergency asset repair, replacement and/or tree trimming activities to restore power after outages caused by in-service asset failures, storm activity, vegetation and animal contacts, human activity interference, and others. Unlike the planned and scheduled renewal work, the scope and nature of emergency response work varies from one event to another. While risk-based analytics enable EPI to forecast the approximate expected volumes of reactive failures each year, the forecasted volumes must be augmented by the results of historical expenditure trending analysis, to ensure that model-based prediction also reflect the impact of its planners' expert judgment.

As EPI enhances its asset management analytics capabilities and continues its plant renewal and system automation activities, it expects to gradually reach a state where the volume of emergency work becomes more stable and predictable year over year. While the only alternative to reactive response expenditures is a greater volume of proactive preventative or predictive asset replacement, EPI planners believe that a certain level of reactive equipment failure restoration expenditures constitutes a balanced asset management outcome, as failure signifies that EPI, and its customers have extracted the maximum value from the system component(s) in question.

All work in this program is performed by internal emergency response crews. In the cases of larger weather-related events, EPI is a party to several Mutual Aid agreements, which enable it to request assistance from Canadian and U.S. utilities as required.

5.1.2.2.6 Critical Defect Replacements

This program covers the costs of reactive asset replacement or refurbishment activities identified as necessary through regular cyclical inspections. When line patrols or equipment inspections identify evidence of material defect, deterioration, damage, vandalism or another sign of imminent failure or safety risk, crew members fill out exception reports identifying the deficiencies uncovered. These reports are translated into reactive work orders which are scheduled and executed based on relative priority. Since this work concerns the asset deficiencies indicative of imminent failure or potential safety or reliability hazard, there are no feasible alternatives to performing this work. Where a range of potential approaches of rectifying the identified deficiency is available (e.g. smaller-scope fixes vs. replacement), these are considered as appropriate on a case-to-case basis.

5.1.2.3 System Service

EPI's System Service investments within the DSP Forecast Period focus primarily on improving system reliability and planning for forecasted growth. As detailed in Section 3.3.2, EPI recognizes the impact of Smart Grid investments on system reliability and overall customer experience. Accordingly, EPI is continuing to invest in distribution automation throughout the Forecast Period in the towns of Chatham and St. Thomas. The selected feeders in these two towns have large customer counts that will greatly benefit from the segmentation provided by this equipment.

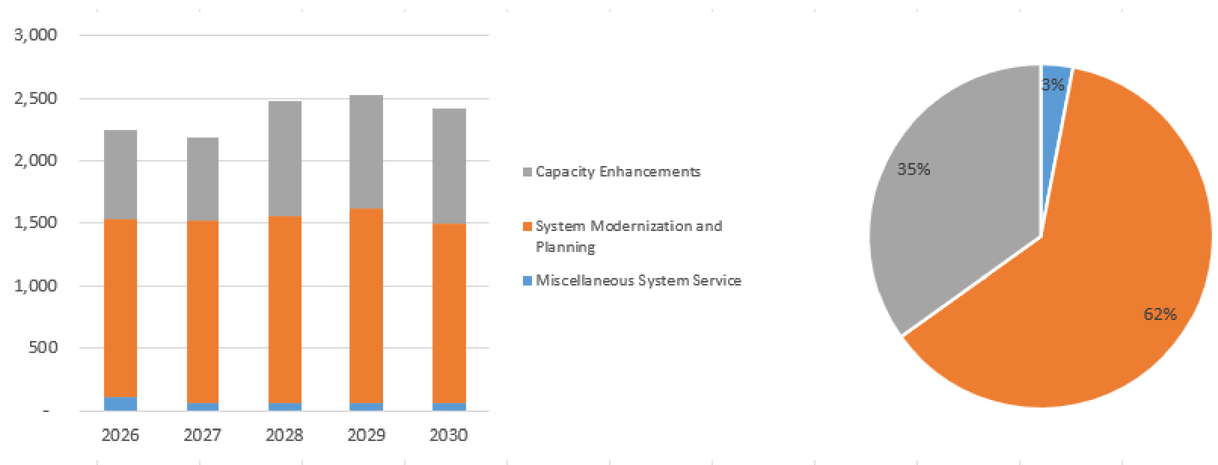
The System Service section includes planned investments in the construction of new 27.6 kV supply points and the phased conversion of existing 8 kV systems to 27.6 kV in the town of 5.1.2.3.. These investments will address the dual needs of forecasted capacity constraints on the existing legacy voltage distribution system and will enable voltage conversion projects in the community.

The short-term objective is to establish the metering points and perform phased voltage conversion projects paced to ensure the capacity of the legacy system is not exceeded. These initiatives are critical for ensuring system reliability and will enhance EPI's operational flexibility, particularly in responding to major C&I connection requests.

For further details by asset category and project level, see Section 5.1.2.3.3, as well as Section 5.3.3.

EPI's portfolio of System Service investments captures the planned activities to reinforce, expand and otherwise modify EPI's distribution system. The need for System Service investments typically arises when EPI forecasts an emerging constraint on its capacity to accommodate new load connections or identifies opportunities to improve the system's reliability performance or operational efficiency through targeted investments in technology. Figure 40 showcases EPI's planned System Service program expenditures over the Forecast Period.

Figure 40: 2026-2030 System Service Expenditure Plan ($'000s)



When planning for System Service investments, EPI relies on the insights generated through the analytical activities completed as a part of its AM process, as well as the results of its collaboration with other entities during the Regional Planning work. The core inputs to system planning work are EPI's load forecasts, capacity and contingency studies, and results of system reliability performance analysis that suggest opportunities to deploy system automation, new feeder tie-ins and/or other enhancements.

Another critical source of information that drives System Service expenditures are the results of customer feedback. Of major significance are the outcomes of ongoing discussion with shareholder municipalities regarding the system's reliability performance in their locales, and/or changes to municipal zoning that may influence the future load growth projections for a specific area. Equally valuable is EPI's interaction with the developer community and individual potential C&I customers exploring opportunities to connect their facilities in the service area.

The following subsections describe the programs that make up the planned System Service expenditures.

5.1.2.3.1 System Modernization and Planning

This program captures the cost of planned enhancements to EPI's reliability performance through additional sectionalisation of existing feeders and installation of automated and/or remotely operated SCADA switches. The primary objective of these capital investments is to reduce the duration of outages experienced by EPI's customers. While increased sectionalisation and automation of feeder tie-points cannot eliminate the underlying sources of outages and their overall occurrence, it does have a potential of substantially reducing the outage scope and duration – an important benefit considering the span of EPI's service territory and the resulting outage response logistics.

Over the 2026-2030 Forecast Period, EPI expects to deploy distribution automation equipment on five feeders. EPI is proceeding with these investments given the successful track record of avoided outages in the parts of its system where similar smart grid devices are already in place. EPI estimates that its existing automation schemes deployed in communities of Wallaceburg, Tilbury, Blenheim, Ridgetown and Chatham have resulted in a combined 124,500 of avoided Customer Hours of Interruption since deployment in 2017. The existing devices prevented the impact of outages that ranged in their causes from faults on the upstream feeders, to Defective Equipment, Vegetation Contact and Foreign Interference (i.e. vehicular collision). Aside from limiting the direct impact of outages on customer operations, feeder automation enables operational savings as outage response costs can be minimized to avoid truck rolls and other cost drivers such as staff overtime.

Feeder Automation is a discretionary investment, and as such, the opportunity cost of proceeding with this investment is commensurate to the benefits that can be derived from any other investments with comparable capital and operating costs, and similar risk mitigation potential. While additional system renewal investments (in lieu of the system automation) could mitigate asset-specific failure risks, the benefit of feeder automation is that it can improve certain aspects of service reliability for a larger area. However, since automation does not eliminate the need for ultimate replacement of deteriorating assets, and does not reduce the frequency of outage occurrences, or safety-related aspects of equipment failure, EPI believes that the differences between the two types of investments differ too substantially to be readily comparable.

Instead, EPI views the automation investments as outage impact mitigation measures that help manage customer reliability in light of the distribution system's geography and condition of the asset base. As such, EPI sees automation as a useful complement (rather than substitute) to replacement work, since the comparatively low investments in automation help maintain reliability, creating greater opportunities to pace renewal work.

EPI's internal staff perform all the work associated with requisite system segmentation and deployment of automation schemes. Project planning and design typically make up a larger portion of expenditures than a typical system renewal project of comparable size, given the technical load flow / system protection studies that are required in advance of deployment. Manufacturers' lead time is also an important consideration, meaning that project planning activities commence well in advance of the anticipated deployment date. Being a discretionary investment, it is also possible that unanticipated expenditure levels in other portfolios may result in EPI shifting the timing of the project to a later year in the Forecast Period, if the equipment delivery date can be changed with the manufacturer.

5.1.2.3.2 Miscellaneous System Service

Substation Capital

As discussed in the context of Voltage Conversion programs, a key planning objective for EPI is to time the voltage conversion activities downstream of its substations in a way that it can decommission all stations without having to undertake any major station renewal investments. While that outcome remains a major priority, some minor expenditures are required from time-to-time to ensure that its substation fleet continues operating safely and reliably. Planned expenditures comprising targeted enhancements in the stations' communications, protection, and safety infrastructure, to ensure that station assets remain safe and operable until conversion work can be completed for the customers the station serves. These investments are not expected to reach the materiality threshold in any of the Forecast Period years.

5.1.2.3.3 Capacity Enhancements

This program supports system capacity expansion through a combination of voltage conversion and proactive upgrading of the most at-risk transformers. In the town of Mount Brydges, this program addresses the construction of new 27.6 kV supply points and the phased conversion of existing 8 kV systems to 27.6 kV. A special consideration in this community is that anticipated customer growth is expected to soon exceed the available capacity of the Hydro One owned distribution stations which serve them. While EPI intends to ultimately fully convert these communities, establishing these 27.6kV supply points now will enable EPI to support growth by converting enough of the community to offset that growth, thus maintaining the legacy system within its ratings until full conversion is scheduled.

Mount Brydges is projected to exceed the available capacity of the legacy voltage system by 2029. To ensure sufficient time for planning and implementation of the required voltage conversion projects, EPI has planned the establishment of a 27.6 kV supply point by 2027. Following the acquisition of the supply point, EPI will begin converting the existing 8 kV infrastructure to the new 27.6 kV network.

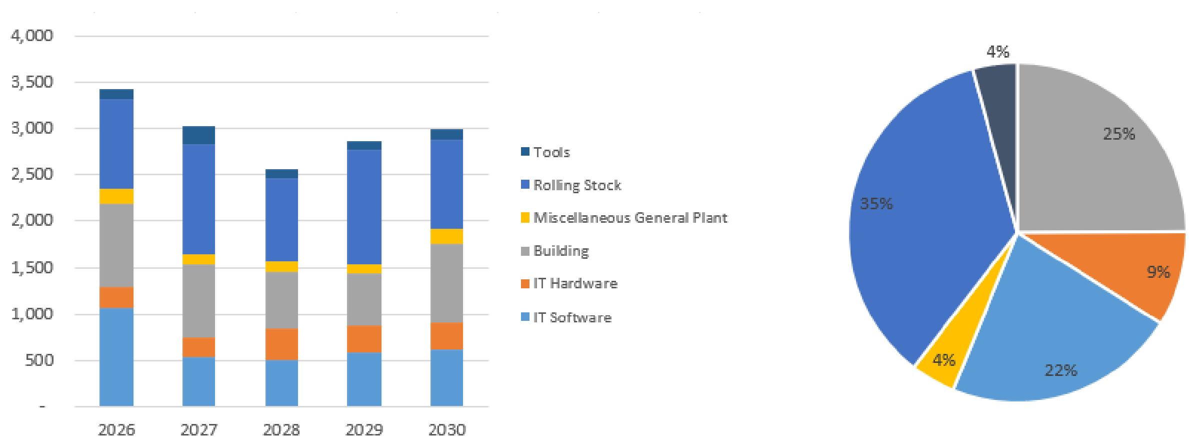
In addition, this program includes $500k in incremental transformer capacity investments to support both near-term reinforcement in areas facing localized load growth and the targeted replacement of transformers identified as most at-risk through AI-enabled analytics. These analytics capabilities, developed by EPI’s Data Scientist, will support the upcoming identification of potential transformer failures by applying machine learning models trained on smart meter data. Outputs will inform engineering decisions and enable more targeted, risk-based investment. This investment reflects EPI’s commitment to forward-looking asset management and was added to the DSP investment plan following Phase Two customer engagement as described in Section 3.2.1.2.2, where the majority of customers expressed support for proactively replacing at-risk transformers.

5.1.2.4 General Plant

The General Plant portfolio includes routine investments in the replacement of end-of-life fleet units, upkeep of facilities, and lifecycle-based renewal of IT assets. Beyond these cyclical activities, the General Plant portfolio allocates funds for roof and HVAC repairs at the Chatham Operating Center, IT investments to upgrade the Customer Information System and website, and numerous security-related enhancements to Endpoint Protection and Firewall systems.

Though General Plant investments target non-distribution assets, they are critical in supporting EPI’s service quality, efficiency, and continuity across all facets of its operations. While being critical to maintaining safe and reliable operation, General Plant investment levels and timing are generally subject to a greater degree of discretion than other investment categories. Section 4.1.3 and Section 4.8 discuss the general plant asset management strategies underlying the planned expenditures showcased in Figure 41.

Figure 41: 2026-2030 General Plant Expenditure Plan ($'000s)



5.1.2.4.1 Tools

This program captures cyclical purchases of various tools used by EPI's crews during their daily activities. Examples include testing equipment, presses, cutters, rubber goods, fault evaluation and infrastructure locating equipment, troubleshooting equipment, radio communication equipment and cable pulling implements. Given the variety of tools and implements that fall into this category and their low materiality, EPI does not consider it practical to maintain a formal asset lifecycle management framework for this group of assets. Accordingly, assets are replaced and replenished as needed – as they reach the ends of their useful lives or require replenishment when considering the anticipated work program. Crew supervisors identify the replacement needs and discuss them with procurement personnel who undertake the purchases. Investment pacing and prioritization are contemplated case-by-case, depending on the current condition of equipment, expected utilization, and materiality of requisite investments.

5.1.2.4.2 Building

This investment program captures the costs of upkeep and enhancements to EPI's operating centres. Key activities planned for the 2026-2030 timeframe mainly include investments in the Chatham facility such as HVAC improvements and roof upgrades, identified through the latest 3rd-party building inspection. Other investments entail minor upgrades and refurbishment to support health and safety of EPI's staff and those visiting EPI's offices.

The scope and timing of specific investments stem from professional assessments and estimation completed by external architectural / civil engineering consultants in consultation with internal staff.

5.1.2.4.3 Rolling Stock

This program includes the costs of repair and replacement of EPI's fleet of vehicles and other specialized mobile equipment. Asset renewal decisions follow the lifecycle management methodology for the appropriate vehicle class discussed in Section 4.9.1. Given the physical span of EPI's service territory, it is imperative that its fleet remains in sound operating condition to respond to outages, complete service requests, and facilitate capital construction and maintenance activities. As vehicles facilitate line crews' direct interaction with the electricity grid, it is equally important for all units to remain in safe operating condition to avoid any potential incidents associated with working at heights, in confined spaces, and next to energized equipment.

EPI has increased the scope of its formal fleet management program since the last DSP. In addition to tracking large and small fleet vehicles (as was done historically), the program now includes trailers, towed equipment (chippers, cable pulling equipment, etc.), small equipment (UTVs, backyard machines, etc.), and yard equipment (tractors, loaders, forklifts, etc.). This provides EPI with a more holistic view of its assets and better enables forecasting of needed expenditures.

5.1.2.4.4 IT Hardware

This program covers the costs of all physical equipment and infrastructure required to maintain and improve EPI's external and internal information technology capabilities. Annual expenditure targets range from personal computing and communication devices (laptops, tablets, cellular phones) to office support hardware (monitors, printers), and back-office infrastructure like server infrastructure.

Benefits of modern and well-maintained IT hardware are the efficiency and flexibility of all utility activities and prevention of cybersecurity threats. All equipment that EPI deploys is equipped with modern encryption and authentication capabilities. Aside from enabling secure and efficient operations, a core strategic goal underlying the hardware portfolio is to fashion a robust infrastructure foundation that is capable to accommodate a variety of emerging technologies that EPI may explore and adopt in the coming years.

EPI manages its IT hardware assets in accordance with a standard Lifecycle Management Policy discussed in Section 4.7.2. Since the technology landscape undergoes rapid evolution, the cyclical asset replacement timelines are frequently revisited, to ensure that they continue reflecting the value add. To the extent permissible by investment needs, EPI attempts to pace its expenditures to maintain a consistent spending profile over time.

5.1.2.4.5 IT Software

The software program includes the licensing costs of new and existing software solutions used by EPI and the labour costs associated with periodic system upgrades and ongoing upkeep and support of the software portfolio. In addition to the standard suite of office support applications, EPI maintains several sophisticated utility-specific solutions, such as those supporting the Metering, Customer Care and Billing, Control Centre, and AM functions, among others. As noted in Section 4.7.1.2, Cybersecurity is a major priority and EPI is actively monitoring and managing any potential vulnerabilities within its software portfolio. Over the Forecast Period, major software expenditure priorities are expected to include:

- A major version upgrade to the Customer Information System – Northstar
- A major website redesign and upgrade to improve customer experience.
- Numerous security related enhancements to our Endpoint Protection and Firewall

5.1.2.4.6 Miscellaneous General Plant

Step-Down Transformer Reduction

This is a specific program that tracks the costs of decommissioning of the step-down distribution substations that support EPI's low-voltage feeders. As the low-voltage feeder infrastructure undergoes conversion to a consistent 27.6 kV standard, the step-down transformer stations become redundant and can be decommissioned. It is EPI's intention to decommission all of its substation infrastructure before any major components require replacement. Over the 2026-2030 plan period, EPI plans to decommission five legacy voltage substations.

In decommissioning the substations, EPI will dispose of the equipment in an environmentally and economically responsible manner, abiding by all the requisite standards and seeking to maximize the stations' residual value through scrap materials and real estate disposal (where feasible). A key longer-term benefit associated with the paced plan of station decommissioning is the ability to divert O&M associated with station testing, inspections and general upkeep to assist with other aging infrastructure in the distribution system, subject to budgetary constraints. Another benefit will be a reduction in the need to stock older vintage station replacement parts.

The only viable alternative to decommissioning the stations once the downstream feeders are converted to the 27.6 kV voltage is to defer the decommissioning. Site-specific options regarding the most efficient and least disruptive logistics of station decommissioning and site restoration work do exist and are appropriately considered at the project design stage on a case-by-case basis.

5.1.3 Forecast Period Plan vs. Historical (5.4.1c)

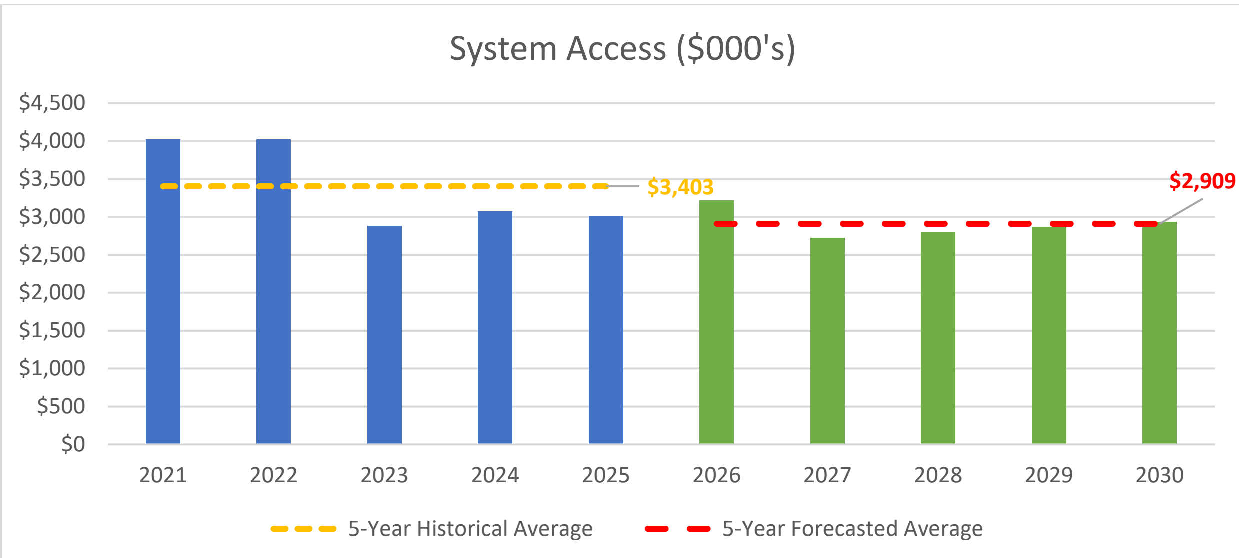
The following section compares forecasted capital expenditures against historical spending across four primary investment categories: System Access, System Renewal, System Service, and General Plant. These comparisons aim to highlight trends, identify drivers for changes, and provide insights into EPI's evolving investment priorities over time. Figure 42 through Figure 46 illustrate these comparisons visually.

5.1.3.1 System Access

As noted in the 2021 DSP, System Access expenditures experienced consistent and unprecedented growth from 2019 through 2022. In the design phase of the 2021 DSP, EPI anticipated that due to the pandemic, the System Access would decline to lower than Historical Period levels in 2022-2025. This expectation was reinforced when many developers put System Access requests on hold at the outset of the pandemic between March 2020 and June 2020. However, when Ontario pandemic restrictions eased in the summer of 2020, the growth surged largely driven by significant demand for residential and subdivision customer connections, with substantial contributions from areas such as St. Thomas, Strathroy, Mount Brydges, and Chatham. This surge had continued into September 2021, such that management updated the 2021 DSP filing to adjust 2022-2025 System Access by an aggregate increase of $3M prior to filing of the DSP in September 2021, in order to reflect a more moderate growth outlook.

Growth began to taper in 2023 and a downward growth trend has continued into 2024 and into early 2025. Accordingly, forecasted expenditures for System Access are projected to decline from historical highs, stabilizing at lower levels throughout the 2026-2030 period. This moderation reflects the anticipated conclusion of pandemic-related housing surges and constraints on available development land within EPI's service territory.

Figure 42: System Access Comparative Expenditures



Note: The figure above reflects the reclassifications of certain program types occurring the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26*).*

5.1.3.2 System Renewal

System Renewal investments during the historical period were characterized by lower-than-planned expenditures in 2021 and 2022, as seen in Figure 43. These reductions were primarily driven by the need to reallocate resources to meet surging System Access demands, which delayed voltage conversion projects and other renewal activities. Starting in 2023, these demands stabilized, allowing EPI to accelerate its renewal expenditures, including focus on voltage conversion. As noted in Section 3.3.1.5, EPI later met its 2021 DSP target of 5 substation decommissionings for the 2021-2025 Historical Period.

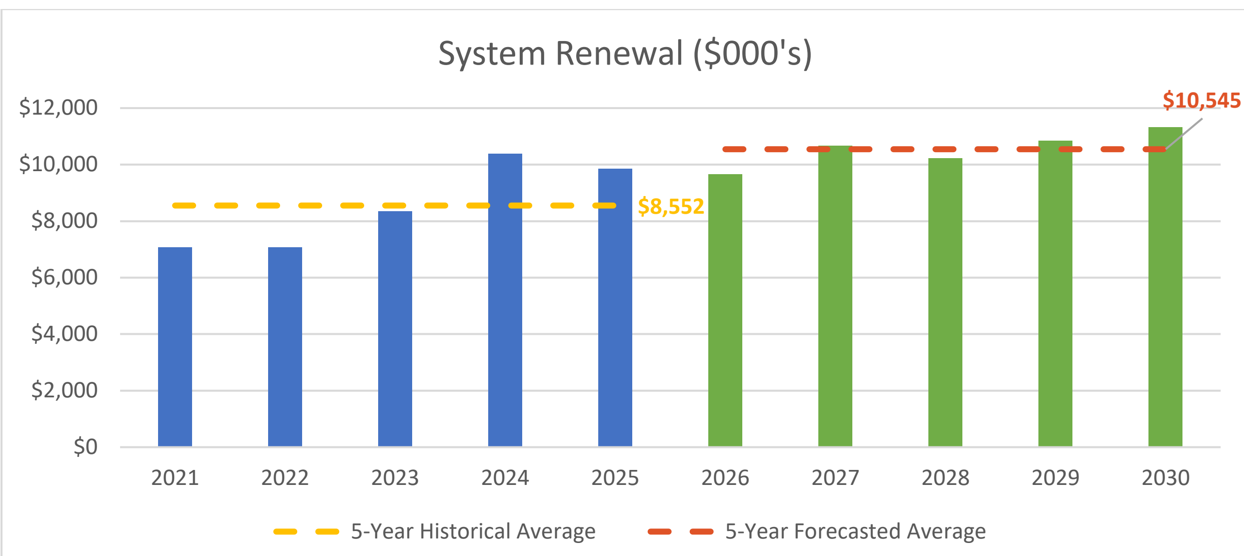
In contrast, forecasted System Renewal expenditures represent an increase – approximately 29% greater than historical averages. This escalation reflects a strategic focus on voltage conversion projects and other renewal initiatives, as informed by customer engagement feedback favoring improved reliability and infrastructure resilience. The planned expenditures aim to address aging assets, reduce technical losses, and improve reliability metrics, with a focused effort on completing critical voltage conversion projects deferred during earlier years.

Investments in metering renewal are a major contributor to the increased spending during the forecast period. This includes the replacement of a substantial number of meters that have reached the end of their lifecycle, failed re-seal extensions, or sustained irreparable damage. During the 2026 – 2030 period, approximately 39,700 meters seal will expire (See Appendix L, “Metering Renewal). Over the last year over 5,000 meters required replacement due to worse than anticipated testing results during recent Measurement Canada resealing testing. One group of polyphase meters is now at the end of its lifecycle. Additionally, upgrades to AMI, such as network servers, signal amplifiers, and the Head-End System, are planned to improve operational efficiency, reduce cybersecurity risks, and maintain compliance with regulatory standards. Spending in this area is forecasted to increase by 54%, ensuring a secure and modern metering infrastructure that meets evolving customer and regulatory requirements.

Inflationary pressures: Supply chain disruptions have led to significantly higher inflation in recent years compared to the historical average. While inflation remained relatively stable and modest through much of the past three decades, the period from 2021 to 2023 experienced a sharp and sustained increase, with 2022 reaching the highest rate in the last forty years. These elevated inflationary conditions have increased the costs of goods, materials, and contracted services, which in turn have directly affected EPI’s cost structure. These pressures are expected to continue influencing project budgets, necessitating careful planning and cost management to ensure that investments remain aligned with EPI’s strategic objectives. See Figure 2.

The forecasted increase in System Renewal spending demonstrates EPI’s commitment to proactive asset management, addressing deferred projects, and aligning investments with customer and operational priorities. This approach ensures that the system is prepared to meet future challenges, including increased electrification, while continuing to deliver safe, reliable, and efficient service to its customers.

Figure 43: System Renewal Comparative Expenditure



Note: The figure above reflects the reclassifications of certain program types occurring the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

5.1.3.3 System Service

System Service expenditures, historically stable, increased significantly in 2025, as illustrated in Figure 44. This increase was primarily driven by the St. Thomas Edgeware TS capacity enhancement described in Section 3.1.2.1.

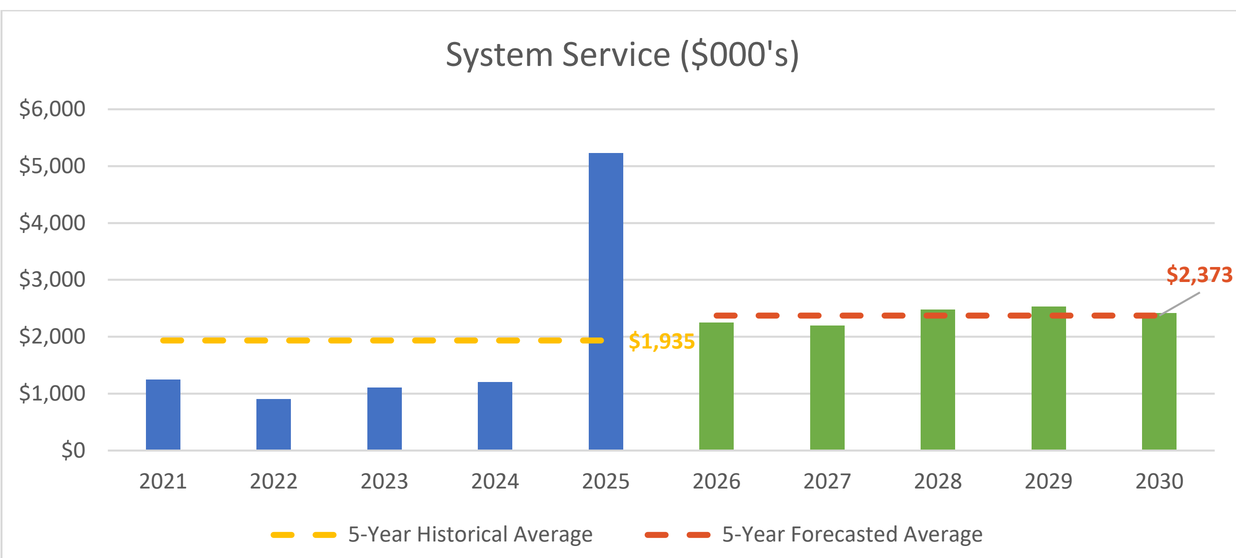
New for the forecast period is spending to improve local capacity through the targeted replacement of at-risk transformers. Please see Appendix L "Capacity Enhancements" and section 5.1.2.3.3 for additional details on these expenditures.

The balance of the increase in expenditures over the forecast period reflects a paced series of planned capacity enablement project at Mount Brydges, which is necessary to address regional load growth and maintain system reliability. (See Section 5.1.2.3)

System Service investments over the forecast period also continue to support the modernization of EPI's distribution grid through the deployment of intelligent sectionalizers, reclosers, and other automation technologies at levels similar to the historical period. These initiatives are complemented by targeted system expansions to accommodate evolving customer demand.

This shift toward a more dynamic and responsive grid is informed by reliability performance analysis and regional development needs. Although automation and sectionalization remain key focus areas, capacity-driven enhancements have become a critical component of the System Service investment plan.

Figure 44: System Service Comparative Expenditure



Note: The figure above reflects the reclassifications of certain program types occurring the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

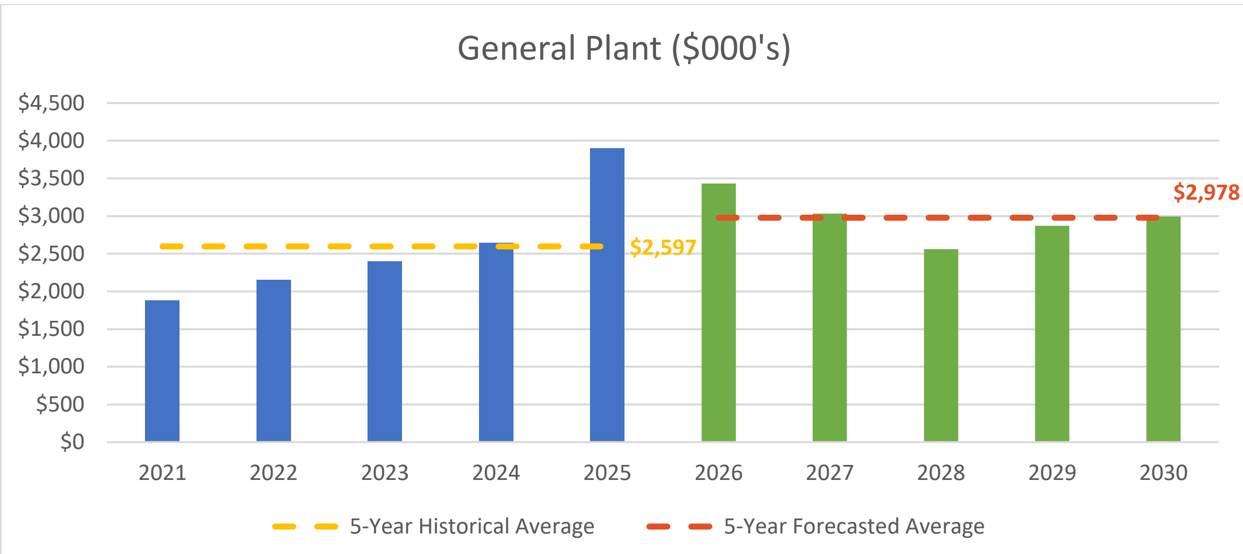
5.1.3.4 General Plant

General Plant investments have shown an upward trend since 2019, driven by increasing costs associated with fleet renewal, facility upgrades, and IT infrastructure improvements. As depicted in Figure 45, forecasted levels of work remain materially consistent with historical levels but costs reflect ongoing upward pressures, including inflationary impacts and rising material costs.

To manage these challenges, EPI has adopted a paced investment approach. Investments in fleet renewal, IT hardware and software modernization, including cybersecurity enhancements and customer-facing system upgrades, remain key priorities within this category.

The sustained investment levels in General Plant reflect EPI's commitment to maintaining operational efficiency and supporting its workforce while addressing the evolving needs of its distribution system.

Figure 45: General Plant Comparative Expenditure



Note: The figure above reflects the reclassifications of certain program types occurring the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

5.1.3.5 Overall Capital Expenditures

EPI's capital spending across the four primary investment categories reflects a strategic evolution driven by shifts in customer demands, system requirements, and external pressures. A detailed comparison of historical spending (2021-2025) versus forecasted spending (2026-2030) reveals key trends and priorities that align with EPI's objectives for system resilience, reliability, and modernization.

The overall capital spending for the 2026-2030 Forecast Period indicates a modest 14% increase compared to the historical period (net capital expenditures). This increase reflects a balanced approach to meeting customer needs, addressing deferred projects, and integrating modern technologies, while also considering inflationary pressures and resource constraints. System Renewal emerges as the dominant investment category, underscoring EPI's commitment to addressing aging infrastructure and enhancing grid reliability.

Comparison Summary by Investment Category:

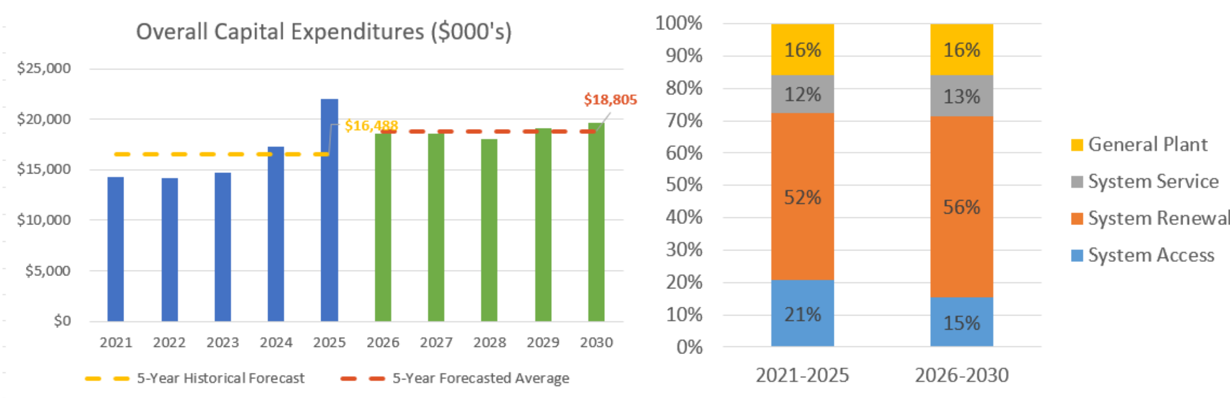
- System Access: Historical spending in this category was elevated due to the pandemic-driven housing surge, which resulted in unprecedented demands for residential and subdivision connections. As connection requests stabilize post-pandemic, forecasted spending levels decline, reflecting a strategic focus on sustainable growth and pacing. This shift enables EPI to allocate more resources to other pressing priorities without compromising its ability to meet new connection needs.
- System Renewal: System Renewal now accounts for nearly 60% of total forecasted expenditures, positioning it as a cornerstone of EPI's capital strategy. Forecasted expenditures in System Renewal highlight EPI's prioritization of critical deferred projects, particularly voltage conversion and metering renewal. These investments target aging assets, reduce technical losses, and improve service reliability. The 54% increase in Metering Renewal underscores the importance of modernizing Advanced Metering Infrastructure, ensuring compliance with regulatory standards, and supporting emerging customer needs. EPI's
- System Service: Spending in System Service remains relatively consistent but shows a modest decline in the forecast period as major initiatives stabilize. Investments in this category focus on deploying intelligent grid technologies, such as sectionalizers and reclosers, to enhance operational flexibility and improve customer reliability. These investments align with EPI's objectives to modernize the grid while maintaining cost efficiency.
- General Plant: Spending on General Plant remains stable, reflecting growing pressures from fleet and facility renewal costs as well as IT modernization initiatives. EPI has implemented cost-containment strategies to address these pressures without compromising operational capabilities. Investments in IT infrastructure ensure the organization is well-equipped to meet future technological demands while maintaining robust cybersecurity measures.

A common theme across all categories is the impact of significantly higher inflation in recent years compared to the historical average. While inflation remained relatively stable and modest through much of the past three decades, the period from 2021 to 2023 experienced a sharp and sustained increase, with 2022 reaching the highest rate in the last forty years. These elevated inflationary conditions have increased the costs of goods, materials, and contracted services, which in turn have directly affected EPI's cost structure. See Figure 2. These factors have significantly influenced overall project costs, requiring EPI to adopt efficient planning and cost management strategies to mitigate their effects.

The comparison of historical and forecasted capital spending highlights EPI's adaptive and forward-looking strategy. The modest increase in overall expenditures reflects a prudent approach to addressing deferred infrastructure needs, modernizing the grid, and aligning investments with customer and regulatory expectations. By prioritizing System Renewal and maintaining a balanced focus across other categories, EPI is well-positioned to deliver reliable, efficient, and sustainable service to its customers.

This approach ensures EPI is prepared to navigate the evolving energy landscape in Ontario, meeting emerging challenges such as electrification and grid modernization while maintaining financial stewardship and operational excellence.

Figure 46: Overall Capital Comparative Expenditure



Note: The figure above reflects the reclassifications of certain program types occurring the 2026 DSP as outlined in Section 5.1.4 (refer to Table 5-26).

5.1.4 Important Modifications to Typical Capital Programs (5.4.1d)

The structure and number of capital programs outlined in the 2021 DSP have been revised and adjusted to align with the current needs of both the distribution system and the organization. Notably, six programs from System Access and System Service investment categories have been either removed, re-categorized or merged with other programs.

The following table lists the programs removed from the 2026 DSP:

Table 5-26: Programs removed from 2026 Capital Project List

Line No.	Description	Reasoning
	SYSTEM ACCESS	
1	Commercial and Industrial Rebuild	"Commercial and Industrial Rebuild" has been merged into "Customer Connections: Commercial & Industrial."
2	Delta - Wye Service Conversions	All Delta - Wye service conversion projects were completed in 2023 and are therefore not included in the 2026 plan.
3	Edgeware Capacity Enhancements	“Edgeware Capacity Enhancements” has been renamed to "Capacity Enhancements" and moved to the System Service category
	SYSTEM SERVICE	
4	Metering Upgrades	"Metering Upgrades" has been removed. Historically, this project included wholesale meter replacements which are now being recorded in “Metering Renewal” under System Renewal.
5	System Automation	"System Automation" project has been combined with "System Modernization and Planning" for 2026.

6	System Reinforcement	"System Reinforcement" project has been merged into "Miscellaneous System Service"

The revised list of capital programs now consists of a total of 23 programs, compared to the 28 outlined in the 2021 DSP. The "Capacity Enhancements" program has been introduced under the System Service category to address a broader range of system-wide capacity constraints and to allow strategic investments aimed at enhancing system capacity as needed. In this DSP, funding allocated to this program include investments in new 27.6 kV supply points and phased voltage conversion in Mount Brydges, along with $500k in incremental transformer investments to address anticipated capacity concerns and proactively replace at-risk units as outlined in Section 5.1.2.3.3.

5.1.5 Potential Impact of Forecast Capital Expenditures on System O&M Costs (5.4.1e)

System investments will result in:

- the addition of incremental plant (e.g. new poles, switchgear, transformers, etc.);
- the relocation/replacement of existing plant;
- the replacement of end of life plant with new plant (e.g. cables, poles, transformers, etc.);
- new/replacement system support expenditures (e.g. fleet, software, etc.);
- decommissioning of older substations.

In general, incremental plant additions (e.g. new distribution automation equipment, etc.) will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs.

Relocation or replacement of existing plant typically results in an asset being replaced with a similar one, leading to little or no change in resources for ongoing O&M purposes (i.e., inspections still need to be carried out periodically as required by the Distribution System Code). Replacing an older piece of equipment with a newer one may result in minor O&M reductions due to new components, although it would also incur incremental O&M during installation. Overall, the planned system investments in this category are not expected to have a material impact on O&M costs due to the offsetting nature of the drivers.

The extent of impact on O&M activity resulting from repairs is largely driven by asset type. For example, poles offer few opportunities for repair-related activities and generally require replacement when deemed at the end of normal life or critically damaged. Other assets, such as direct buried cable, offer opportunities for repair-related activities (e.g., splices), although up to a point where further repairs are not warranted due to end-of-life conditions. If assets approaching end of life are replaced at a rate that maintains the equipment class average condition, then repair levels and changes to O&M costs are expected to be minimal, all else being equal. However, replacement rates that improve the equipment class average condition could result in lower costs for some maintenance activities (e.g., pole testing, reactive repairs), thereby reducing O&M repair-related costs. Without ongoing investment in asset renewal, the degradation of infrastructure condition would accelerate, increasing the likelihood of failures and driving higher reactive maintenance costs. By systematically renewing aging assets, the capital plan mitigates potential upward pressure on O&M spending by slowing the rate of system degradation and reducing the need for unplanned repairs.

System support expenditures (e.g., GIS, ACA studies) provide a better overall understanding of assets, leading to more efficient and optimized design, maintenance, and investment activities going forward. However, to improve the quality of data used in the ACA studies, increased data collection efforts are required, which increase O&M costs. The recent GIS upgrade allowed EPI to streamline its licensing, with increasing demands for additional analysis and GIS complexity expected to offset some of these savings. Overall, system support expenditures are not expected to have a significant impact on total O&M costs in the Forecast Period.

The decommissioning of substation assets is expected to divert some O&M associated with station testing, inspections, and general upkeep to assist with other aging infrastructure in the distribution system. Another benefit will be a reduction in the need to stock older vintage station replacement parts and a reduction in property tax at these locations.

Fleet, facilities, and IT-related capital expenditures are not expected to have a material impact on O&M. Fleet replacement expenditures will result in reduced O&M for new units.

To conclude, EPI does not anticipate that its planned capital investments over the 2026–2030 period will have a material impact on system O&M costs. The capital plan has been developed with consideration of potential capital and O&M trade-offs, and no significant O&M cost reductions or increases are expected as a direct result of the proposed investments.

5.1.6 To Non-Distribution Activities (5.4.1f)

EPI's capital and O&M plans do not contain any non-distribution activities.

5.2 Justifying Capital Expenditures & Overall Plan (5.4.2)

EPI's capital expenditure plan for the 2026-2030 period reflects its commitment to meeting customer needs while addressing aging infrastructure, system reliability, regulatory compliance, and grid modernization challenges. The plan was developed through a rigorous, iterative planning process aligned with the OEB's Chapter 5 Filing Requirements. It incorporates customer feedback, asset management insights, and risk assessments to ensure investments deliver value while maintaining prudent financial stewardship. This section provides a capital budget process overview, detailed justification for EPI's proposed investments, explaining how they align with strategic objectives, customer preferences, and regulatory expectations.

5.2.1 Capital Budget Formulation and Allocation Process

EPI's capital budget process is built on its AM framework, which applies planning objectives, assumptions, and methodologies to guide the development of investment plans. The asset planning process is described in Section 4.1.1 and ensures that the principles guiding asset management decisions are consistent with EPI's Mission, Vision and Core Values, including the delivery of safe, reliable, and sustainable electricity services. The process includes asset inspection and testing, asset condition assessment and the creation of the ACA report.

By grounding capital planning in AM principles, EPI ensures that investments address system needs and risk mitigation priorities, while aligning with broader corporate objectives. The approach draws on subject matter expertise and risk evaluation to support a capital investment plan that is technically sound, reliable, and adaptable.

During development of the capital expenditure plan EPI applies a consistent set of planning objectives. These planning objectives map to the relevant DSP objectives and performance measures, serving to operationalize them. The mapping is detailed in Table 4-1. From Section 4.1, these include:

- Public/Employee Safety: Construct and operate the system in a manner that minimizes the probability and/or impact of injuries to staff, contractors and the public.
- Environment: Continuously explore and execute on ways to manage the impact of EPI's asset base and operating activities on the natural environment.
- Reliability: Deploy an optimal mix of System Renewal, System Service and O&M solutions to minimize the number and duration of power outages experienced by EPI customers, including those occurring due to loss of upstream supply
- Grid Modernization: Manage infrastructure to accommodate increasing load demands, to integrate DERs and to support electrification and customer growth. capacity for load customers and DER's.
- Operational Efficiency: Continuously explore and execute on opportunities to reduce the labour-intensive components of EPI's capital and maintenance work through investments in new technology and managerial innovation.
- Cost Effectiveness: Deploy new capital in a manner that seeks to minimize asset lifecycle costs across all utility functions.

As detailed in 4.1.3.1, the capital planning process incorporates multiple inputs including:

- ACA outputs
- Metering asset verification data
- Field asset inspections
- Facility asset inspections
- IT asset inspections
- Reliability data
- Power quality data
- System loss data
- Environment, health and safety performance data
- Third-Party feedback including customer consultations and engagement activities (see Section 3.2.1)
- General plant performance and utilization data
- Customer connection process data
- Growth and load forecasts (including generation)

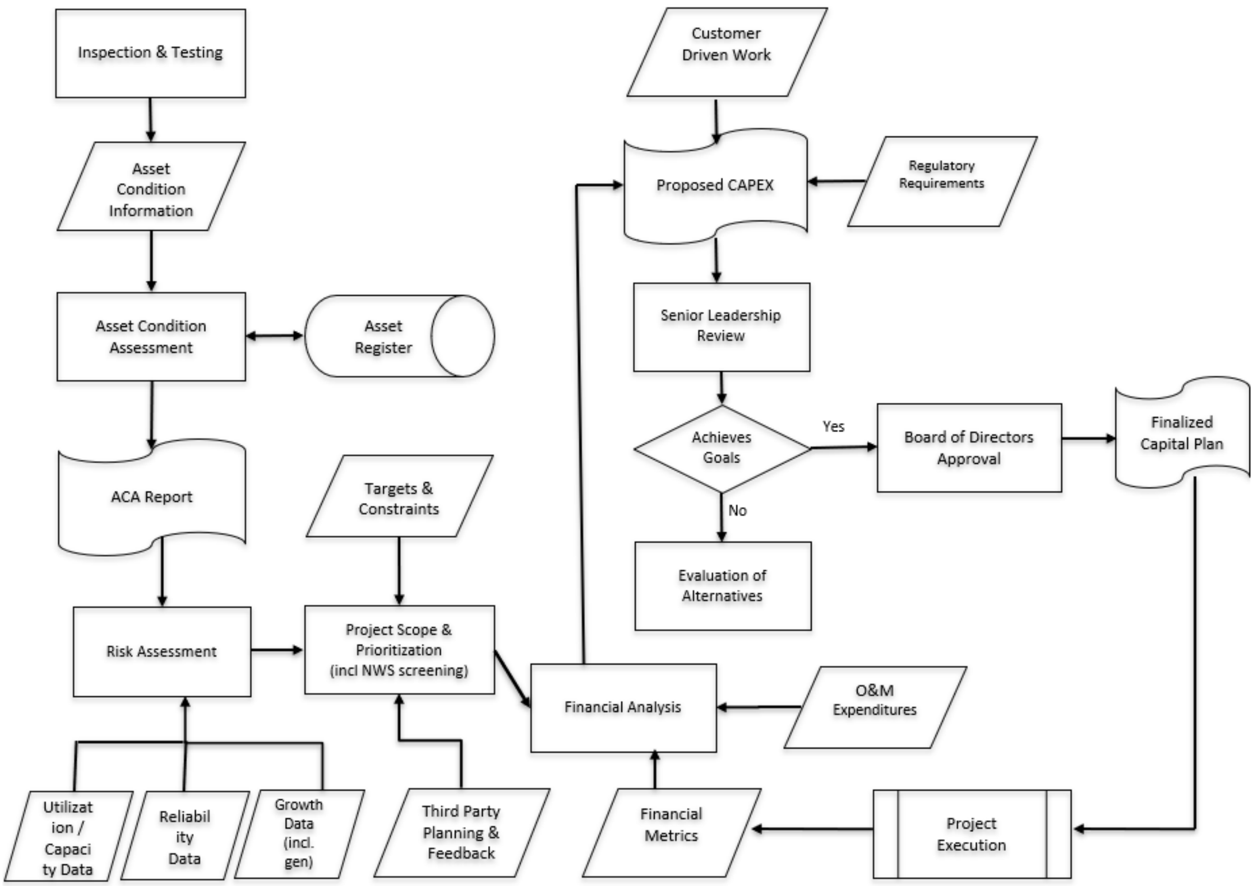
- System modernization and regulatory requirements, including electrification considerations (eDSM, DERs, EV and heat-pump adoption)
- System utilization analysis

These inputs inform both the one-year capital budget (n+1) and the four-year outlook (n+2 to n+5), as well as the respective O&M budgets. The process is led by departmental subject matter experts, who prepare bottom-up forecasts annually based on the above planning objectives and inputs. This approach ensures that capital plans reflect evolving system conditions and operational knowledge.

Operational departmental budgets are submitted to the Planning department for aggregation and capital expenditures are categorized by System Access, System Renewal, System Service, and General Plant. The Planning team provides cross-functional coordination, trend analysis, and consistency checks to support the development of a cohesive and technically sound investment plan.

The Finance department integrates the draft capital plan into EPI's financial planning framework, producing business plan financial statements. These statements include proposed funding sources, projected debt covenant calculations, and an overall assessment of financial leverage (debt to capital). The senior leadership team then reviews the consolidated plan to confirm alignment with corporate objectives. Alternatives are considered at this stage that may impact on the timing or pacing of certain projects. Once finalized, the capital expenditure plan is submitted to the Board of Directors for review and approval.

Figure 47: Flowchart of the EPI Capital Planning Process



EPI continuously improves its planning process by reviewing lessons learned from completed projects, including cost performance, technical results, and delivery outcomes. These insights help refine future assumptions and priorities. Project delivery is monitored for performance and compliance with technical expectations.

5.2.2 Capital Expenditures Plan

The 2026–2030 Plan reflects EPI's commitment to ensuring system reliability, accommodating growth, and addressing aging infrastructure while maintaining focus on customer affordability and operational efficiency.

The proposed investments align with the OEB's four performance outcomes – customer focus, operational effectiveness, public policy responsiveness, and financial performance as outlined in Table 3-5 – while also achieving EPI's internal AM objectives. These objectives emphasize delivering safe, reliable, and sustainable electricity services while integrating modern technologies, addressing emerging needs and continuously improving operations.

The proposed expenditures prioritize ongoing projects initiated in the 2021-2025 Historical Period, such as voltage conversion and meter infrastructure upgrades, while addressing new priorities like grid modernization and cybersecurity. The plan employs a phased approach to investments, aligning timing with need and ensuring expenditures are paced to avoid unnecessary rate impacts. By leveraging its AM process, EPI ensures that capital plans are both forward-looking and adaptable to evolving system and customer requirements.

The Plan aligns with OEB Requirements:

- Delivering Value to Customers: EPI's plan emphasizes delivering value by controlling costs, optimizing investment decisions, and pacing expenditures to mitigate rate impacts. This ensures affordability while addressing critical system needs and evolving customer expectations.
- Integrating Innovation and Modernization: The plan includes targeted investments in grid modernization to support electrification, DERs, and enhanced operational flexibility. These investments position EPI to meet future challenges effectively.
- Addressing Traditional Planning Needs: The plan ensures capacity to accommodate load growth, replaces deteriorated legacy infrastructure, and improves reliability through proactive and reactive projects.

EPI develops its Plan to avoid "lumpy" investments through strategic pacing and prioritization of capital expenditures, balancing long-term objectives with affordability. However, some variability is unavoidable as capital projects cannot be arbitrarily divided without losing project efficiency. An example is the new breaker at Edgeware TS that EPI is working with Hydro One to install, from which EPI will build a new feeder to address existing St. Thomas capacity constraints. See further discussion at Section 3.2.6.2. Investments are aligned with load forecasts, regional needs, and emerging technologies to ensure their timing delivers maximum value.

EPI actively manages the impacts of its capital expenditures on customer rates by prioritization and pacing. The company's planning emphasizes achieving a balance between maintaining reliable service and ensuring affordability. Deferred lower-priority projects, cost-containment strategies, and resource optimization help control expenditures while addressing critical needs. EPI integrates customer feedback to align investments with preferences for reliable, cost-effective services, ensuring that rate increases remain reasonable and justifiable.

EPI provided a comprehensive analysis of its capital spending for each investment category (Section 0) and compared 2021-2025 Historical Period and 2026-2030 Forecast Period expenditures (Section 5.1.3). The plan highlights the distribution of investments across System Access, System Renewal, System Service, and General Plant categories. Supporting tables and figures illustrate expenditure trends, justifying increases due to factors like inflation, labor costs, and material price hikes.

The Capital Expenditure Plan demonstrates the following Category-Specific justifications:

- **System Access**
  Historical spending on System Access was driven by unprecedented residential and subdivision growth during the 2019-2022 period. In the Forecast Period, expenditures stabilize to address connection requests efficiently, while supporting electrification and DER integration. Key priorities include:

    - Efficiently addressing new and connection upgrade requests.
    - Aligning with regulatory obligations under the Distribution System Code, specifically, relocation of utility infrastructure driven by requests from provincial, regional, municipal, or private sector entities.
    - Supporting ongoing FTTH projects, driven by growing demand for telecommunications infrastructure.
- **System Renewal**
  System Renewal is the largest investment category, reflecting EPI's focus on addressing deferred projects, replacing aging assets, and enhancing reliability. Significant initiatives include:
    - Voltage conversion projects to modernize low-voltage infrastructure, reduce technical losses, improve reliability, while avoiding costly station asset renewal investments.
    - Meter renewal and AMI upgrades to ensure accuracy, compliance, and efficiency.
    - Proactive and reactive replacements of end-of-life assets, guided by robust AM processes.
- **System Service**
  Investments in System Service aim to enhance grid flexibility and operational efficiency through:
    - Deployment of intelligent sectionalizers and reclosers to improve fault detection and response times.
    - Construction of new feeder ties in multiple locations to improve transfer capacity and reliability.
    - Construction of feeder ties, particularly in the northeast region, and allow for greater operational flexibility.
    - Development of additional capacity through new 27.6kV supply feeders in the community of Mount Brydges.
    - Integration of advanced grid monitoring systems to support real-time decision-making.
    - Ongoing support of EPI's Control Room and continued enhancements to its Asset Management and field inspection capabilities.
- **General Plant**
  General Plant expenditures focus on IT modernization, fleet upgrades, and facility renewals. Key initiatives include:
    - Strengthening the protection of sensitive data and critical operational systems against cyber threats, ensuring compliance with industry standards and maintaining customer trust.
    - Implementing lifecycle-based replacements to optimize efficiency and reduce maintenance costs. These upgrades include extending the service life of vehicles and introducing modern tools that enhance operational effectiveness.
    - Addressing aging infrastructure to maintain compliance with safety standards and provide a safe, reliable working environment for staff and contractors.
    - Investing in IT solutions, including enhanced data storage and cybersecurity measures, to improve the efficiency of operations and the security of customer data. These initiatives also support GIS system advancements, enabling more robust and advanced data analysis capabilities.

The total level of capital expenditures is challenged by inflation-driven cost increases, including supply chain disruptions and rising labor costs. EPI mitigates these impacts through strategic procurement practices, resource optimization, and cost-containment measures to ensure investments remain efficient and value-driven.

EPI's 2026–2030 capital expenditure plan is a well-justified, forward-looking strategy that aligns with OEB requirements and customer expectations. By addressing aging infrastructure, modernizing the grid, and balancing affordability with system needs, the plan positions EPI to deliver reliable, cost-effective, and sustainable services in an evolving energy landscape. Through prudent fiscal management, robust AM processes, and a commitment to operational excellence, EPI ensures that its investments provide long-term value for customers and stakeholders alike.

5.3 Material Investments (5.4.3.2)

This section focuses on EPI's planned material investments for the 2026–2030 period, as defined by the materiality thresholds outlined in Chapter 2 of the OEB Filing Requirements. EPI's materiality threshold is $195,000, as described in Section 5.1. These investments are critical to maintaining system reliability, meeting customer and regulatory expectations, and addressing emerging needs such as electrification and grid modernization.

The prioritization of projects is guided by EPI's AM Planning Objectives, which align with the four OEB objectives. Each project is evaluated using weighted criteria to ensure alignment with EPI's strategic goals, customer feedback, and regulatory compliance. Table 4-1 in Section 4.1.1 details AM Objectives and Prioritization Weightings for the Projects.

As a theme, safety driven projects will receive maximum priority, followed by projects driven by legislative requirements. Projects where Entegrus has greater discretion on scope and timing will generally fall below those in the list, even when these projects drive reliability and long-term distribution system sustainability.

The two highest ranking programs in the tables below fall in the system renewal category and involve safety, which are functionally legislative requirements. The next two project are in general plant and are driven by the idea that they support every aspect of EPI's ability to operate. Four of the next five are system access and form EPI's primary responsibility and mandate as a distributor. Three of the next four are in system renewal and are driven by improvements to reliability and operational efficiency. EPI's largest expenditure program, voltage conversion, is within the first three of the truly discretionary spending programs that isn't driven by a regulatory or safety requirement.

Section 5.1 provides a detailed breakdown of project drivers. These drivers influence the prioritization and pacing of investments to maximize value for customers while ensuring fiscal responsibility.

The tables below summarize the material investments across the four major categories: System Access, System Renewal, System Service, and General Plant. These tables include prioritization rankings and annual spending projections. For a comprehensive review of each project, please refer to Attachment J.

5.3.1 System Access

Table 5-27: 2026-2030 System Access Prioritization ('000s)

Line No.	Description	2026	2027	2028	2029	2030	Priority Ranking
1	Contributed Capital	-$1,671	-$1,699	-$1,749	-$1,783	-$1,819	-
2	Customer Conns: Commercial & Industrial	$1,437	$1,477	$1,520	$1,557	$1,595	8
3	Customer Conns: Residential & Subdivision	$1,903	$1,953	$2,009	$2,040	$2,073	9
4	Engineering Support Capital	$700	$721	$742	$765	$788	4
5	Miscellaneous System Access	$716	$154	$159	$163	$168	19
6	Third Party Attachments	$134	$118	$122	$125	$129	10
7	**Total System Access**	**$3,219**	**$2,723**	**$2,803**	**$2,867**	**$2,933**	

5.3.2 System Renewal

Table 5-28: 2026-2030 System Renewal Prioritization ('000s)

Line No.	Description	2026	2027	2028	2029	2030	Priority Ranking
1	Critical Defect Replacements	$312	$321	$330	$339	$347	2
2	Emergency Response	$856	$879	$905	$921	$937	1
3	Metering Renewal	$2,931	$3,006	$2,576	$2,478	$2,546	14
4	Miscellaneous System Renewal	$179	$183	$188	$194	$200	20
5	Operation Support Capital	$1,037	$1,072	$1,104	$1,137	$1,171	3
6	Pole Replacement	$589	$604	$621	$632	$643	13
7	Transformer Replacement	$199	$204	$210	$215	$221	12
8	Voltage Conversion	$3,555	$4,396	$4,300	$4,933	$5,255	15
9	**Total System Renewal**	**$9,656**	**$10,665**	**$10,233**	**$10,848**	**$11,320**	

5.3.3 System Service

Table 5-29: 2026-2030 System Service Prioritization ('000s)

Line No.	Description	2026	2027	2028	2029	2030	Priority Ranking
1	Miscellaneous System Service	$166	$108	$110	$112	$113	22
2	System Modernization and Planning	$1,372	$1,410	$1,449	$1,502	$1,381	7
3	Capacity Enhancements	$708	$673	$921	$914	$925	11
4	**Total System Service**	**$2,245**	**$2,191**	**$2,480**	**$2,528**	**$2,419**	

5.3.4 General Plant

Table 5-30: 2026-2030 General Plant Prioritization ('000s)

Line No.	Description	2026	2027	2028	2029	2030	Priority Ranking
1	Building	$903	$791	$597	$563	$855	16
2	IT Hardware	$218	$210	$343	$284	$293	6
3	IT Software	$1,072	$535	$504	$590	$608	5
4	Miscellaneous General Plant	$164	$104	$120	$88	$161	21
5	Rolling Stock	$957	$1,195	$894	$1,240	$970	17
6	Tools	$119	$199	$102	$105	$108	18
7	**Total General Plant**	**$3,433**	**$3,034**	**$2,560**	**$2,870**	**$2,995**	