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September 15, 2021

Ms. Christine Long
Ontario Energy Board
PO Box 2319
27th Floor, 2300 Yonge Street
Toronto, Ontario M4P 1E4

Re: Entegrus Powerlines Inc. 2021-2025 Distribution System Plan

Dear Ms. Long,

Please find enclosed the Entegrus Powerlines Inc. ("Entegrus") 2021-2025 Distribution System Plan ("DSP").

On March 15, 2018, the OEB approved a Mergers, Amalgamation, Acquisitions and Divestures ("MAAD") application (EB-2017-0212) submitted by Legacy Entegrus and St. Thomas Energy Inc. ("STEI") which sought leave to amalgamate. In the EB-2017-2012 Decision and Order, the OEB approved the deferral of rate re-basing for the merged entity until 2026 and accepted the Legacy Entegrus / STEI proposal to file a consolidated DSP in 2021. Given the above-noted rate-rebasing deferral, this DSP is not accompanied by a Cost of Service application.

Entegrus has developed this 2021-2025 consolidated DSP filing in accordance with the OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements dated June 24, 2021, as well as the key principles and specific outcomes underlying the Renewed Regulatory Framework ("RRF"). There are no Incremental Capital Module ("ICM") or proposed rate impacts for the 2021-2025 Forecast Period arising from this DSP.

The primary contact for this application is the undersigned at regulatory@entegrus.com. If you have any further questions, please do not hesitate to contact me.

Regards,

[Original signed by]

David C. Ferguson
Vice President of Regulatory & Human Resources
Phone: 519-352-6300 Ext 4558

cc: Jim Hogan, President & CEO
Chris Cowell, Chief Financial and Regulatory Officer
Tomo Matesic, Vice President of Engineering & Operations
Matthew Meloche, Senior Manager of System Planning

Distribution System Plan

Historical Period:

2016 – 2020

Forecast Period:

2021 - 2025

September 15, 2021

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B. August 2021 Customer Engagement Results, Prepared by Innovative Research Group
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E. Local Planning Report: Chatham-Kent/Lambton/Sarnia, June 2017
F. Greater Bruce/Huron Region Scoping Assessment, September 2019
G. Chatham-Kent/Lambton/Sarnia Regional Infrastructure Plan, August 2017
H. Windsor-Essex Region Integrated Regional Resource Plan, April 2015
I. IESO Letter of Comment
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GLOSSARY

ACA – Asset Condition Assessment

AM – Asset Management

AMP – Asset Management Process

CAIDI – Customer Average Interruption Duration Index

CI – Customers Interrupted

CHI – Customer Hours Interrupted

CSA – Canadian Standard Association

DSC – Distribution System Code

DSP – Distribution System Plan

EOL – End of Life

Entegrus – Entegrus Powerlines Inc.

ESA – Electrical Safety Authority

GIS – Geographic Information System

GS – General Service

GUP – Good Utility Practice

IESO – Independent Electricity System Operator

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

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

0 EXECUTIVE SUMMARY

Planning Context

Entegrus Powerlines Inc. ("Entegrus") has developed this 2021-2025 integrated Distribution System Plan ("DSP") filing in accordance with the Ontario Energy Board's ("OEB") Chapter 5 Consolidated Distribution System Plan Filing Requirements dated June 24, 2021, as well as the key principles and specific outcomes underlying the OEB's Renewed Regulatory Framework ("RRF").

There are no proposed rate impacts for the 2021-2025 Forecast Period arising from this DSP filing.

On March 15, 2018, the OEB approved a Mergers, Amalgamation, Acquisitions and Divestures ("MAAD") application (EB-2017-0212) submitted by Legacy Entegrus 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 Entegrus. 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.

Given the above-noted rate-rebasing deferral, this DSP is not accompanied by a Cost of Service application. This is Entegrus' second DSP filing[1], following the inaugural 2015 submission (EB-2015-0061) for the 2016-2020 period ("the 2016 DSP"), the results of which form the Historical Period of this submission. A major development reflected in this second edition of the DSP is the amalgamation of Entegrus' assets and service territory and those of the former STEI. Accordingly, the investments underlying this DSP are a product of an integrated assessment of asset needs across the entire amalgamated service territory. Further, this second DSP incorporates the lessons learned from the previous DSP processes and reflects a multitude of operating insights gained and improvements put in place over the last five years.

This DSP balances a stronger investment focus on reliability (System Renewal) and unprecedented customer growth (System Access) in 2020 and 2021 (which is expected to moderate starting in 2022), with an objective of keeping distribution rates affordable for customers. Accordingly, while System Renewal investment levels in particular have increased above historic levels in 2019 and 2020 and will continue to remain at higher-than-historic levels through 2025, there are currently no proposed incremental customer rate (or bill) impacts arising from this DSP filing for the period from 2021-2025.

Moreover, to-date, Entegrus has not filed any Incremental Capital Module ("ICM") applications and as of the point of submission of this DSP filing and based on customer feedback and preferences that showed a strong preference for affordability, does not currently plan for any ICM applications in the 2021-2025 period. However, a situation may evolve in the future that requires Entegrus to file an ICM application in the 2021-2025 period and Entegrus expressly reserves its right to do so if this does occur.

[1] The former St. Thomas Energy made one DSP submission (EB-2014-0113)

2021-2025 Forecast Period Capital Expenditure Plan

Leveraging the Asset Management and Planning tools and processes described throughout this document, Entegrus has developed a five-year Capital Expenditure Plan as captured in the table below and substantiated throughout this document. This 2021-2025 DSP continues and expands on key focus areas of the 2016 DSP: replacement of aging infrastructure and modernization of the distribution system to maintain (or improve) reliability while keeping distribution rates affordable for customers.

Notably, this DSP is predicated on Entegrus' September 2021 planning practices when planning and co-ordinating investments with Internet Service Providers ("ISPs") to support expansion of broadband infrastructure to Entegrus hydro pole lines. The recent passage of the Supporting Broadband and Infrastructure Expansion Act, 2021 ("SBIEA") is anticipated to result in changes to the planning, co-ordination and breadth of broadband expansion. The outcomes of practice changes from the SBIEA are continuing to evolve at the time of filing of this DSP and any impacts to the DSP are unknown.

Table 0-1 presents Historical Period capital expenditures for the pre-merger legacy utilities from 2016-2017, as well as post-merger 2018-2020 actual capital expenditures. It also provides planned expenditures for the 2021-2025 Forecast Period. Note that all Historical Period capital expenditures are presented on a combined basis below.

Table 0-1 Entegrus Summary of Capital Expenditure Plan

Line No.	Description	Historic Period Actual					Forecast Period Plan				
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	System Access	$2,969	$3,914	$4,169	$5,719	$6,245	$5,867	$4,308	$6,010	$3,909	$3,926
2	System Renewal	$5,624	$4,035	$4,518	$4,592	$6,121	$7,238	$7,669	$7,872	$9,380	$9,395
3	System Service	$914	$1,667	$1,213	$1,223	$1,731	$1,063	$968	$987	$1,944	$1,519
4	General Plant	$1,345	$2,148	$1,973	$2,383	$1,805	$1,974	$2,051	$2,088	$2,121	$2,150
5	**Total Expenditure**	**$10,852**	**$11,764**	**$11,874**	**$13,917**	**$15,902**	**$16,142**	**$14,996**	**$16,957**	**$17,355**	**$16,991**
6	Capital Contributions	-$1,501	-$1,944	-$1,454	-$3,357	-$2,726	-$3,367	-$2,300	-$2,356	-$2,413	-$2,471
7	**Net Capital Expenditures**	**$9,351**	**$9,820**	**$10,420**	**$10,559**	**$13,176**	**$12,775**	**$12,696**	**$14,601**	**$14,942**	**$14,520**

The 2021-2025 Forecast Period Plan demonstrates a notable increased focus on System Renewal. As discussed in Section 1.5.1, this is driven by the fact that portions of the Legacy Entegrus distribution system have degraded beyond the expectation of the 2016 DSP and is borne out by recent deterioration of reliability measures, as seen in Section 2.3.3.1.2. The increase in System Renewal investment starting in 2020 focuses on this dynamic. In early 2020, Entegrus focused on replacement of at-risk poles. After the onset of the pandemic in March 2020, Entegrus line crews continued to work in the field and were re-organized into two-person units. With many developers putting System Access requests on temporary hold, the engineering department and lines crews were re-tasked to focus primarily on System Renewal with many safety precautions in place. This represented an opportunity to "jump start" the critical System Renewal work described above for the 2021-2025 Forecast Period. While addressing degraded infrastructure, this system remediation work will provide a stronger distribution system foundation for more integration of electric vehicle and distributed generation infrastructure investments in the next planning cycle (i.e., the Entegrus 2026-2030 DSP). Further, the customer engagement process showed a preference for Entegrus to conduct additional voltage conversion (System Renewal) work in this DSP. These additional planned conversion investments are included in the 2024/2025 System Renewal in table above and are described in more detail in Section 4.1.3.2.

System Access also increased significantly in 2020 and 2021, driven by unprecedented Residential customer growth in the City of St. Thomas, as well as high growth in in other communities in the Entegrus northeast region, particularly Strathroy and Mt. Brydges, as well as the southwest region (particularly Chatham) as described in Section 1.4.6. These customer-driven requests are a top priority, and simultaneously balancing the above-described System Renewal dynamic into the daily construction work plans is vital. Accordingly, Entegrus has increased its roster and utilization of underground and overhead contractors in the latter part of the Historical Period. This will provide additional operational flexibility, as although the growth trend is now expected through 2021, the remainder of the Forecast Period growth is expected to moderate due to the anticipated end of pandemic-related housing trends, as well as constraints to the supply of available development land within established service territory boundaries. Notably, System Access also includes a 2023 planned investment for a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas, as discussed in Section 4.2.1 and Section 4.2.2. Entegrus is also investigating other solutions to address future loading capacity in St. Thomas, but a decision regarding these alternatives has yet to be made in this regard.

Both the Historical Period and the Forecast Period demonstrate a strong focus on system modernization within System Service, including distribution automated restoration (via reclosers and automated load break switches) to mitigate certain loss of supply events, as well as additional sectionalization of feeders. It also includes further harmonization of systems across the merged entity, particularly the conclusion of the post-merger extension of Legacy Entegrus technologies and processes into St. Thomas. This has included the extension of the Legacy Entegrus SCADA, GIS and Control Room systems into St. Thomas. Many other enhancements have occurred in St. Thomas, including the IT developments discussed in Section 3.3.3 and the building enhancements in Section 3.3.4. The customer engagement process showed a preference for Entegrus to install additional automated switches (System Service) in Chatham and St. Thomas in this DSP. These additional planned investments are included in 2024/2025 System Service in the table above and are described in more detail in Section 4.1.3.2.

Historically, when unanticipated System Access demand was tracking to exceed budgeted amounts, management re-allocated the necessary funds to System Access by making adjustments to the scope of other planned projects where pacing discretion existed (typically System Renewal). Accordingly, a current challenge is that unprecedented growth has occurred simultaneous with the increasing need to address aged and degraded infrastructure. In the design phase of this DSP, it was anticipated that due to the pandemic, System Access would slow and then decline to lower than Historical Period levels in 2022-2025 – which would allow proportionately more resource dedication to System Renewal. This expectation was reinforced when many developers put System Access requests on hold between March 2020 and June 2020, which facilitated the shift in focus to System Renewal work. However, when Ontario pandemic restrictions eased in the summer of 2020, growth surged again, particularly in St. Thomas, Strathroy, Mount Brydges and Chatham. This surge has continued into September 2021. In recognition that moving forward, both System Access and System Renewal need to be simultaneous areas of focus, management updated this DSP filing in September 2021 to adjust 2022-2025 System Access by an aggregate increase of $3M over prior expectations while maintaining System Renewal forecast levels. This coincides with the above-noted expansion of the roster and utilization of underground and overhead contractors. At the same time, management has earmarked the above-noted additional system conversion and automated switch investments (see Section 4.1.3.2) planned for 2024/2025, for timing re-examination in 2024 based on prevailing circumstances at that time, including reliability metrics and the level of capital requirements at that time.

The Entegrus commitment to keeping distribution rates affordable is evident by the fact that there have been no proposed incremental rate impacts since the merger, nor are any such proposals expected to arise from this DSP filing for the 2021-2025 Forecast Period.

Key investment drivers for the 2021-2025 Forecast Period, comprising the current work program, are summarized as follows under each of the four asset categories

System Access – Key Investment Drivers:

- Anticipated new residential subdivisions across growing Entegrus communities, particularly due to the high residential growth in St. Thomas, as well as higher growth Northeast region communities of Strathroy and Mt. Brydges – and more recently, Southwest region communities such as Chatham (which is experiencing an "out-migration" trend whereby former residents of the GTA relocate to Chatham). In addition, System Access also includes a 2023 investment for a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas in 2023 as discussed in Section 4.2.1 and Section 4.2.2;

- Anticipated connection of new customer premises or upgrades/modifications to existing facilities to accommodate changing capacity needs or other customer requests;

- Relocation of utility infrastructure driven by requests from provincial, regional, municipal, or private sector entities;

- "Fibre to the Home" projects, driven by multiple fibre companies expanding their networks, which requires Entegrus engineering studies, make-ready work and often asset replacements (which are partially offset by capital contributions); and

- Investment in a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas in 2023.

System Renewal – Key Investment Drivers:

- Proactive and reactive replacement of aged and degraded distribution infrastructure, including replacement of assets that have reached end of useful life through asset management planning and/or field inspection work and which is contributing to the recent deterioration in reliability measures;

- Conversion of deteriorated low-voltage overhead and underground feeders to modern 27.6 kV infrastructure designed to latest technical and safety standards. Customer engagement indicated a customer preference for a faster pace of conversion, which has been incorporated into this DSP;

- Life extension work is also required and occurring on some legacy low-voltage substations while conversion work is ongoing; and

- Ongoing refresh of Advanced Metering Infrastructure (AMI) assets and a paced replacement of customer smart meters on a rolling community basis at the end of their re-seal periods with one harmonized smart meter system, along with associated communication equipment and the lifecycle replacement of core infrastructure such as gateways and servers.

System Service – Key Investment Drivers:

- The creation of additional system operational flexibility through re-conductoring and additional tie points between feeders to increase segmentation and system resiliency;

- Construction of new feeder ties in multiple locations to reduce outage instances experienced by Entegrus customers, as well as sectionalization and distribution automation to allow for automatic restoration implementation. Customer engagement indicated a customer preference for additional automated switch investment in Chatham and St. Thomas, which has been incorporated into this DSP; and

- Ongoing support of the Chatham-based Control Room and continued enhancements to overall Asset Management and field inspection capabilities.

General Plant – Key Investment Drivers:

- Investments in Hyperconverged IT Infrastructure, Data Storage and Cybersecurity to improve the operating efficiency and security of customer data, which continues to support the recent enhancements to the GIS system and digital modernization of the Control Room;

- Facilities investments to modernize the core building systems in Chatham and facilitate the closure of the Strathroy operating centre in 2021 Q4 and its integration into the St. Thomas operating centre, as more fully described in Section 3.3.4; and

- Lifecycle-based replacement of vehicles and tools and implements that enable Entegrus staff to perform their regular tasks safely and reliably.

These and other projects planned for the 2021-2025 timeframe make up a portfolio of normal-course, pragmatic investments, typical for a utility which serves mature municipalities, while enabling regional economic growth. Using the planning tools that have substantially matured since its 2016 DSP filing, management has developed a work program that addresses the most significant risks and enhances the operating flexibility of the system, while advancing the key elements of its longer-term Asset Management strategy.

While a recent pre-pandemic customer survey showed a lack of planned customer uptake of electric vehicles and distributed generation in the 2021-2025 Forecast Period (see Section 0), management is confident that this DSP filing and associated investment will provide the appropriate distribution system foundation for more integration of electric vehicle and distributed generation infrastructure investments in the next planning cycle (i.e. the Entegrus 2026-2030 DSP).

Entegrus and its Distribution System

Entegrus serves 17 communities located in four different IESO Regional Planning Zones (London Area, Greater Bruce-Huron, Chatham-Kent/Lambton/Sarnia, and Windsor-Essex), covering an area of approximately 5,600 square kilometres. The driving distance and time between the northernmost community (Parkhill) and southernmost community (Wheatley) in Entegrus' service area amounts to approximately 170 km and two hours, respectively. Entegrus is a product of the Chatham-Kent (single tier) municipal amalgamation in 1998, as well as multiple acquisitions and amalgamations with smaller Southwestern Ontario utilities dating back to 2005. Consistent with its pedigree and the evolution of Entegrus as described in Section 1.3 above, the Entegrus distribution system consists of a variety of voltages, vintages, designs and configurations reflecting the choices of its municipal and corporate predecessors. While Entegrus has taken material strides towards standardizing its equipment and operating standards, much work remains to be completed across the 17 communities and drives a significant portion of the System Renewal investments in this DSP. As the remainder of this document showcases, the pacing and sequencing of capital work is a product of increasingly sophisticated analytics and investment prioritization tools.

Entegrus currently maintains operating centres in Chatham, Strathroy and St. Thomas. As described in Section 3.3.4, in 2021 Q4, Entegrus will consolidate the Strathroy operating centre into its St. Thomas operating centre (the two buildings are approximately 50 km apart). Thereafter, Entegrus will continue to lease the garage and yard in Strathroy as a staging facility to house selected rolling stock, equipment and supplies. This will provide for after hour service response times.

Depending on the community, Entegrus assets connect into those of Hydro One Networks Inc. ("Hydro One") at either transmission or distribution levels. Connections are a mix of 27.6kV and 8.0kV. As a highly embedded distributor, Entegrus' reliability is substantially influenced by upstream supply. Entegrus has recently undertaken a program to augment supply reliability with automated switching in our communities where technically feasible. Whether in the context of Customer Engagement, Regional Planning, or a variety of industry collaboration forums, Entegrus collaborates successfully with its upstream supplier, the IESO and its neighbouring distributors. Several prudent planning decisions and specific system performance improvement initiatives described in this document are a testament to this collaboration. This includes working with Hydro One protection and control personnel regarding the installation of circuits in Tilbury and Wallaceburg that have combined to help avoid nearly 18,000 Customer Hours Interrupted ("CHI") since being installed in 2017.

As the development of this DSP coincided with the social and economic impact of the COVID-19 pandemic, Entegrus, its staff and customers recognize that their plans, forecasts and expectations regarding the five-year period at the core of this plan are subject to a greater degree of uncertainty than a typical planning horizon. Nevertheless, Entegrus believes that good utility practice demands that planning must proceed based on the best estimates and assumptions available at the time. As new insights and circumstances emerge, Entegrus will adjust its plans and operating practices to best match the emerging conditions.

1 INTRODUCTION

Entegrus Powerlines Inc. ("Entegrus") has prepared this 2021-2025 Distribution System Plan ("DSP", or "Plan") in accordance with the Ontario Energy Board's ("OEB") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated June 24, 2021 (the "Filing Requirements"). This DSP filing is a consolidated planning document that incorporates the results and investment plans for Entegrus' assets, including those of the former St. Thomas Energy Inc. ("STEI"), which, as previously noted, amalgamated with Entegrus on April 1, 2018.[2]

Since its 2018 amalgamation, Entegrus has taken a variety of critical steps to harmonize the operations of the two predecessor utilties and assess the future investment priorities across the consolidated service territory. To the extent that this work impacts the planning and operation of Entegrus' distribution system, this document addresses it in the relevant sections.

Entegrus retained METSCO Energy Solutions Inc. ("METSCO") to advise on and assist with the preparation of this DSP and perform several supporting activities described in this Plan.

1.1 OBJECTIVES & SCOPE OF WORK

This document is the first consolidated DSP of the two previously independent predecessor utilities, each of which filed a separate DSP in their last Cost of Service Application.[3] Accordingly, this DSP seeks to accomplish several objectives:

- report on the predecessors' results relative to the commitments made in their last DSP filings;
- relay the results of consolidated operations and the progress of integration work still underway;
- articulate the scope, nature and evidentiary basis of the investments planned for 2021-2025.

The DSP documents the tools, processes and policies that are currently in place to facilitate informed and efficient investment decisions to support Entegrus' desired outcomes in a cost-effective manner. The Entegrus 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 2020 report (released August 2021), Entegrus was tied for 14th place in terms of the most efficient distributors in the province (of 59 distributors ranked).

[2] Ontario Energy Board, EB-2017-0212, Decision and Order, "Application for approvals to effect the amalgamation of Entegrus Powerlines Inc. and St. Thomas Energy Inc." March 15, 2018
[3] St. Thomas Energy Inc. Cost of Service Application: EB-2014-0013; Entegrus Powerlines Inc. Cost of Service Application: EB-2015-0061

Further, this DSP also seeks to update the OEB and other interested stakeholders on the progress of post-amalgamation consolidation activities – most notably those related to the asset management and capital program planning and implementation functions.

Of note, this DSP filing does not result in any requests for incremental capital or operations funding. Also important is the fact that the historical reporting period for this document includes two distinct phases – namely the years 2018 and 2019 when the utility operated on a consolidated basis, and years 2016 and 2017 over which the two predecessor utilities operated as separate entities. To distinguish between these two phases, this document uses the terms "Combined Historical Period" and "Predecessor Historical Period" respectively. Consistent with this terminology, this document presents the results of the Predecessor Historical Period separately for each of STEI and Legacy Entegrus ahead of the amalgamation (referred collectively throughout this document as the "Predecessor Utilities").

For the purposes of this DSP, years 2016 through 2020 have been treated as the Historical Period. Since this DSP filing is not accompanied by a Cost of Service application, there is not a requirement for a Bridge year. Further, given that the Plan does not result any incremental rate requests, there is no Test Year associated with this plan. Instead, the year 2021-2025 are individually referred to as Plan Year 1 (PY1) through Plan Year 5 (PY5), or collectively as the Forecast Period.

The DSP represents Entegrus' efforts to develop an impactful investment work program, while delivering a service offering that balances the four key Renewed Regulatory Framework (RRF) outcomes:

1. ***Customer Focus:*** *provision of services in a manner reflective of identified customer needs and preferences;*

2. ***Operational Effectiveness:*** *leveraging continuous improvement opportunities in productivity and cost performance, while meeting system reliability and service quality objectives;*

3. ***Public Policy Responsiveness:*** *deliver on the obligations mandated by government in legislation and in regulatory requirements; and*

4. ***Financial Performance:*** *maintaining financial viability while seeking out and capitalizing on sustainable operational effectiveness improvement opportunities.*

In seeking to develop a five-year plan to support the continued balancing of these objectives, Entegrus relied on a combination of objective asset data, the results of its ongoing performance measurement work, 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 judgment on organizational priorities and the socioeconomic environment of its service territory. As noted above, there are no proposed incremental rate impacts arising from this DSP filing for the period from 2021-2025, which is consistent with Entegrus' intention to keep distribution rates affordable for customers.

1.2 Outline of the Report

This is Entegrus' second DSP and was prepared in accordance with the OEB' Chapter 5 filing requirements, and the first such document covering the combined operations of the Legacy Entegrus (also referred to as "Entegrus-Main") and the former STEI. The report contains four sections, including this introductory *Section 1*. *Section 2* provides a high-level overview of the DSP framework, including the evidence of coordinated planning work involving other entities, and the recent results and forward-looking plans concerning Entegrus' performance measurement framework. *Section 3* entails an overview of Entegrus' asset management practices, including the recap of their evolution since the 2016 DSP filing. *Section 4* showcases Entegrus' 2021-2025 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 4 also contains the justifications for material capital projects and programs (above the materiality threshold of $130,000 as described in Section 4.3) planned for the 2021-2025 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.

1.3 The Evolution of Entegrus

Chatham Hydro was the largest predecessor to what is now Entegrus and was founded in 1914. Subsequently, Chatham-Kent Hydro ("CKH") was formed in 1998 as an amalgamation of eleven former Municipal Electric Utilities ("MEUs"). The amalgamation of the MEUs was part of the municipal amalgamation of approximately twenty-two municipalities and townships into what is now the Municipality of Chatham-Kent.

The former CKH was a local electricity distribution company (OEB Distributor Licence ED-2002-0563) serving the Ontario communities of Blenheim, Bothwell, Chatham, Dresden, Erieau, Merlin, Ridgetown, Thamesville, Tilbury, Wallaceburg, Wheatley, and certain designated land parcels in the Township of Raleigh, known as the Bloomfield Business Park.

On March 24, 2005, CKH's parent company, the former Chatham-Kent Energy Inc. ("CK Energy"), submitted MAAD application EB-2005-0255 requesting Board approval to acquire all shares of Middlesex Power Distribution Corporation ("MPDC"). At that time, MPDC was a local distribution company (former OEB Distributor Licence ED-2003-0059) servicing the Ontario communities of Strathroy, Mount Brydges and Parkhill.

The Board approved this acquisition in its Decision and Order issued on June 24, 2005. CK Energy's acquisition of MPDC subsequently closed June 30, 2005.

On October 15, 2008, MPDC submitted MAAD applications EB-2008-0332 and EB-2008-0350 requesting Board approval to acquire all shares of the former Dutton Hydro Limited and the former Newbury Power Inc. and to amalgamate all entities into MPDC. The Board approved these acquisitions and the amalgamation in its Decision and Order issued February 9, 2009. MPDC closed this transaction on April 30, 2009. Subsequently, MPDC served the distribution areas formerly licensed to each of MPDC, Dutton Hydro Limited & Newbury Power Inc. and maintained separate rate zones for each of these three areas.

On August 31, 2011, CKH applied to the Board for leave to amalgamate MPDC with CKH (MAAD applications EB-2011-0328 and EB-2011-0329). On December 16, 2011, the Board approved the amalgamation, and on January 11, 2012, CKH notified the Board that this transaction was complete. On January 20, 2012, CKH received its amended Licence ED-2002-0563 and notification from the Board that the MPDC Licence ED-2003-0059 was cancelled.

Subsequently, on January 31, 2012, CKH applied to the Board to amend the company name on its Electricity Distribution Licence (ED-2002-0563) to Entegrus Powerlines Inc. ("Entegrus"). The Board approved this change and issued an updated Licence on February 24, 2012.

On August 28, 2015, Entegrus filed its comprehensive 2016 COS Application (EB-2015-0261) for distribution rates effective May 1, 2016, which also sought harmonization of the four previous rate zones of: (i) Chatham-Kent, (ii) Strathroy, Parkhill & Mt. Brydges, (iii) Dutton and (iv) Newbury. On February 3, 2016, Entegrus and the parties to the Application submitted a full Settlement Agreement on all matters to the Board for approval. Subsequently, the Board approved this Settlement Agreement in full in its Decision and Order dated March 17, 2016.

On July 21, 2017, Entegrus and St. Thomas Energy Inc. ("STEI") submitted a MAAD application (EB-2017-0212), seeking approval to amalgamate and continue as Entegrus. At that time, STEI was a local distribution company (former OEB Distributor Licence ED-2003-0563) servicing the city of St. Thomas, Ontario. On March 15, 2018, the Board approved the amalgamation and the deferral of rate re-basing for the merged entity until 2026. Notably, the Board also accepted the proposal to file a consolidated Distribution System Plan in 2021. Subsequently, Entegrus notified the Board that the transaction was complete, effective April 1, 2018. On April 19, 2018, Entegrus received its amended Licence ED-2002-0563 and notification from the Board that the STEI Licence ED-2002-0523 was cancelled.

As described in EB-2017-0212, Entegrus plans to maintain two separate rate zones (Entegrus-Main and Entegrus-St. Thomas) until such time as rates are re-based.

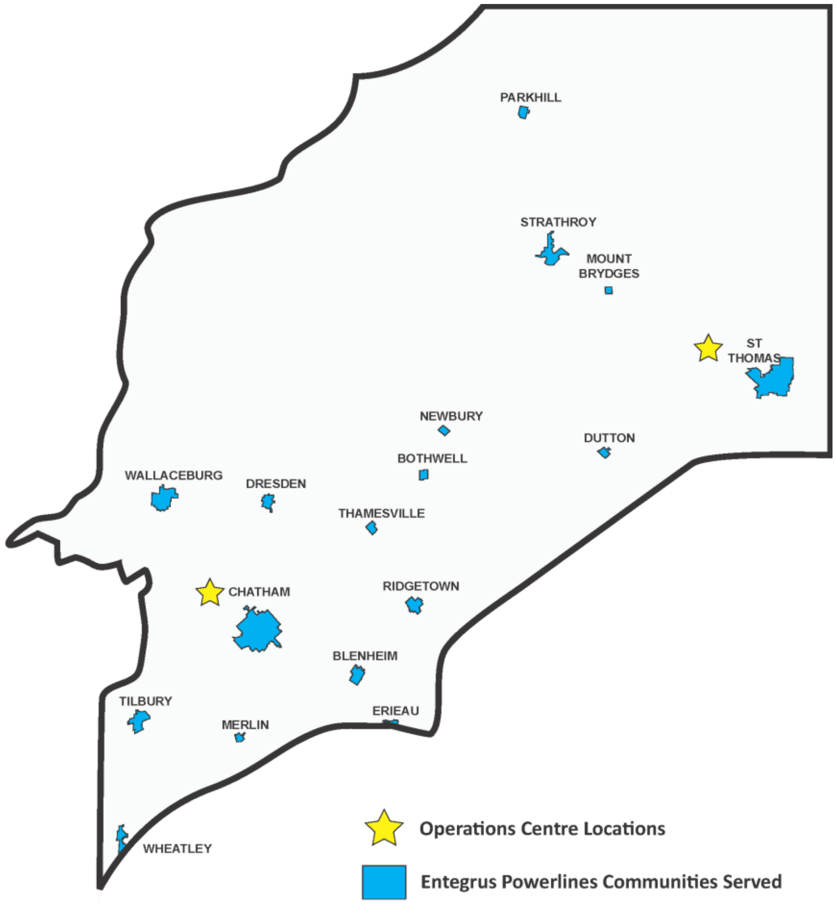
As of 2020, Entegrus had 60,588 metered customers and ranked approximately 12th in the Province of Ontario in terms of electrical utility size by number of metered customers.

1.4 DESCRIPTION OF ENTEGRUS

1.4.1 General Utility Facts

Entegrus is a regulated electricity distributor that owns and operates distribution systems serving 17 communities in Southwestern Ontario prescribed in its Electricity Distribution License ED-2002-0563. As of December 31, 2020, Entegrus served 60,588 customers, which were made up of predominantly Residential and Small General Service. Figure 1-1 displays Entegrus' service territory, which covers 132 km² of non-contiguous urban areas dispersed across a 5,000 km² geographic area stretching between Windsor (to the west), London (to the east), Sarnia (to the north) and Lake Erie (to the south).

Figure 1-1: Entegrus Service Territory



The Entegrus 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 Entegrus' asset base is the amalgamation of Entegrus' assets with those of the former STEI, approved by the OEB on March 15, 2018 by way of a Decision and Order on the MAAD application (EB-2017-0212) filed by Entegrus' corporate predecessors. Owing to this most recent amalgamation, the total customer count of pre-merger Entegrus to post-merger Entegrus has grown by almost 50%. Among others, Sections 2.1.1.1, 2.1.3, and 3.3 contain additional information on the integration activities impacting the preparation of this DSP.

Given the non-contiguous nature of its service territory, Entegrus receives power from Hydro One Networks Inc. ("Hydro One") both at transmission and distribution voltages (as an embedded distributor). As the relevant sections of this Plan discuss, Entegrus maintains a regular collaborative relationship with Hydro One on a variety of planning and operational matters impacting the utilities' neighbouring assets. As previously noted, this collaboration has led to notable positive service outcomes for the communities served by Entegrus, such as the improvement of instances of Loss of Supply-related service outages, collaboration on local area system planning studies, and collaborative approach to power quality investigations. Power quality was a key focus of the 2016 DSP. The focus on power quality studies continues but the successes achieved have reduced the volume of such activity (see Section 2.1.6.2).

1.4.2 Regional Planning Activities

The Entegrus service territory falls into four separate Regional Planning Zones overseen by Ontario's Independent Electricity System Operator (IESO):

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

Given its presence across multiple planning areas, Entegrus participates in all regional planning activities across Southwestern Ontario (west of London). These planning activities typically occur every year and relate to the development of bulk, regional and local electricity systems within one or more of the Planning Zones. Section 2.2.3 of this DSP summarizes the results of the Regional Planning Activities impacting Entegrus' service territory over the Historical Period and outlines their impact on planning over the Forecast Period.

1.4.3 Corporate Structure

Entegrus is a subsidiary of Entegrus Inc., a corporation incorporated under the *Ontario Business Corporations Act*, 1990 and jointly owned by the Municipality of Chatham-Kent, the Corporation of the City of St. Thomas and Corix Infrastructure Inc. Aside from Entegrus, Entegrus Inc. owns three other subsidiaries engaged in the activities described below:

- Entegrus Services Inc. ("ESI"): broadband communication and data hosting services
- Entegrus Transmission Inc. ("ETI"): owns and sublets a utility land corridor running from Chatham-Kent (Tilbury) to Elgin County (St. Thomas)
- Entegrus Renewable Energy Inc. ("EREI"): a dedicated entity to oversee wind generation investments on behalf of Entegrus' shareholders.

Entegrus' operational, financial, and oversight/reporting frameworks are in full compliance with the OEB's *Affiliate Relationships Code* ("ARC"), as most recently attested in June of 2020 as a part of its 2019 Annual Reporting and Record Keeping Requirements ("RRR") results compliance filing.

1.4.4 Mission, Vision, and Core Values Statement

In integrating the assets and expertise of previously separate Southwestern Ontario utilities, Entegrus forged a foundation of its corporate values – grounded in pursuit of operational excellence and keen attention to the needs of local customers and community. Today, Entegrus' corporate Vision is "*To be an industry leader in all we do*."

The Entegrus Vision is supported by a Mission Statement "*To provide safe, reliable delivery of electricity and related services, in an environmentally and fiscally responsible manner. To provide exceptional service to our customers, support the communities we serve and provide rewarding growth opportunities for our employees*."

In implementing its Mission and Vision statements, Entegrus relies on a framework of five fundamental Corporate Values that drive strategic and operational decision-making. These Corporate Values are:

> *Safety*: safety first in everything we do.
>
> *Inspired and Empowered People*: having a workforce of inspired and empowered people who are passionate about their jobs.
>
> *Customer and Community Focus*: exceeding the needs of customers and the communities we serve, by having a customer and community focus.
>
> *Operational Excellence*: achieving operational excellence by always striving for continuous improvement.
>
> *Sustainable Growth*: delivering sustainable growth for our stakeholders through wise investments.

1.4.5 Corporate Strategic Goals

The above framework of corporate Vision, Mission, and Values is reflective of values of both of Entegrus' most recent corporate predecessors, which were significantly aligned pre-amalgamation. This is evidenced in the fact that STEI's previous Vision statement was "To be the industry leader in energy solutions and services"[4] – an articulation that is closely consistent with the above-noted Entegrus vision.

Regarding the discipline of Asset Management ("AM") more specifically, the two predecessors also maintained a generally consistent strategic outlook, as evidenced by the following areas of focus overlap over the most recent Historical Period:

- A generally conservative planning approach to the annual volumes of System Renewal and System Service work, reflective of the focus on keeping customer rates low;
- An ongoing emphasis on proactive conversion of aged and deteriorated low-voltage feeders built to legacy design standards to new and consistent higher-voltage infrastructure; and
- Pursuit of safety and process improvement opportunities as evident through Entegrus' successful company-wide adoption of the Infrastructure Health & Safety Association's (IHSA's) Certificate of Recognition (COR) and through STEI's focus on standards like ISO5500x and ISO9001.

Entegrus expects these broad areas of congruence between the two predecessors' approaches to remain relevant for this DSP's Forecast Period, management will continue to identify and execute most critical investments justified by available objective performance information. As the remainder of this Plan showcases, management has leveraged a number of operating insights and improvements to its

[4] STEI 2015-2019 DSP, p.2, filed in EB-2014-0113, Exhibit 2-1-11, April 25, 2014

analytical tools and processes to put forth a capital program supported by thorough engineering and economic analysis.

1.4.6 Customers Served

At the end of 2020, Entegrus served 60,558 electricity distribution customers across its service area. This represents an aggregate 5.0% increase from the beginning of the Historical Period (2016) covered in this Plan.[5]

The City of St. Thomas has experienced unprecedented Residential customer growth into 2020 and 2021, some of which was the subject of service area amendments. At the same time, Legacy Entegrus communities (particularly Strathroy and Mt. Brydges) started to experience higher customer growth. This growth trend appears to have been driven by the proximity of all three of these communities to London, to which they are increasingly seen as bedroom communities.

Historically, from 2006 to 2015, the former STEI experienced an average customer growth rate of 1.0% per year. Over the 2016-2020 period, the St. Thomas growth rate increased to 1.7% per year. In comparison, Legacy Entegrus experienced an average customer growth rate of 0.3% per year from 2006 to 2015. However, between 2016-2020, Legacy Entegrus experienced an average growth rate of 0.7%. As described in Section 2.1.1.4, management is more recently aware of an “out-migration” trend, whereby former residents of the Greater Toronto Area (“GTA”) are migrating into the Entegrus service territory, which may have continued to spur the new housing start trend in late 2020 and 2021 (particularly in Chatham, but in other Entegrus communities as well). In aggregate, for the merged Entegrus, all of this equates to an average growth rate from 2016-2020 of 1.0% and results in a recent near doubling of the System Access activity.

In the design phase of this DSP, it was anticipated that due to the pandemic, the above-described growth would slow and then decline to lower than Historical Period levels in 2022-2025. This expectation was reinforced when many developers put System Access requests on hold between March 2020 and June 2020. However, when Ontario pandemic restrictions eased in the summer of 2020, growth surged again, particularly in St. Thomas, Strathroy, Mount Brydges and Chatham. Notably, the Entegrus Residential growth rate was 1.4% for 2020 (led by a St. Thomas year-over-year Residential growth rate of 2.4%) – despite the temporary pandemic halt. This surge has continued into September 2021, such that management updated this DSP filing to adjust 2022-2025 System Access by an aggregate increase of $3M prior to filing of this DSP in September 2021, in order to reflect a more moderate growth outlook. This moderate growth outlook remains consistent with the anticipated end of pandemic-related housing trends, as well as constraints to the supply of available development land within established service territory boundaries.

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[5] Customer numbers sourced from annually published OEB Yearbooks. Ending 2016-2017 historical data has been combined for comparison purposes.

Table 1-1 below depicts the changes in customer numbers over the Historical Period for the former STEI and Legacy Entegrus and starting in 2018, the combined Entegrus result. It is evident that the high Residential customer growth has been somewhat offset by a decrease in General Service > 50 kW customers, particularly in the City of St. Thomas, although management is tracking significant industrial development and expansion currently underway or being planned for the northeast region.

Table 1-1: Entegrus' 2016-2020 Customer Base

Year	Description	Rate Class				Total
		Residential	General Service < 50kW	General Service > 50kW	Large Use	
2016	STEI	15,389	1,722	135	-	17,246
	Legacy Entegrus	36,478	3,907	446	2	40,833
	Total	51,867	5,629	581	2	**58,079**
2017	STEI	15,651	1,737	131	-	17,519
	Legacy Entegrus	36,780	3,943	417	2	41,142
	Total	52,431	5,680	548	2	**58,661**
2018	Entegrus	52,940	5,692	552	2	**59,186**
2019	Entegrus	53,550	5,695	563	2	**59,810**
2020	Entegrus	54,315	5,712	559	2	**60,588**

1.4.7 System Demand and Efficiency

1.4.7.1 System Demand

Table 1-2 below showcases the annual peak demand (kW) data for the STEI and Legacy Entegrus for 2016 and 2017 and the combined Entegrus' distribution system for the remaining of the Historic Period. Consistent with most other parts of the province, Entegrus' system experiences the periods of peak demand during the summer months. Variances in seasonal peaks are generally attributable to expected short-term volatility in weather conditions and the impact of changes in the number of heating and cooling degree days in a year.

Table 1-2: Peak System Demand Statistics

Year	Description	Peak System Demand (kW)		
		Winter Peak	Summer Peak	Average Peak
2016	STEI	45,181	58,935	46,949
	Legacy Entegrus	141,000	175,468	143,950
	Total Combined*	186,181	234,403	190,899
2017	STEI	44,867	54,276	44,707
	Legacy Entegrus	133,853	173,916	140,978
	Total Combined*	178,720	228,192	185,685
2018	Entegrus	181,302	231,782	184,558
2019	Entegrus	194,207	229,174	190,625
2020	Entegrus	180,772	252,034	188,191

**Total Combined represents the addition of the independent LDC's non-coincident peak values.*

In Legacy Entegrus' 2016 DSP, it was noted that Entegrus experienced a notable decrease in system load in 2010 as a result of the economic recession. Legacy Entegrus' load has steadily recovered since and growth within the service territory has been managed within current capacity.

Entegrus initially anticipated being required to accommodate further growth within the Forecast Period for the city of Chatham. Aside from the new residential and commercial developments, Entegrus had also anticipated demand from a large agricultural operation that was in the process of establishing facilities in previously vacated factories in the area. This facility's anticipated connection requirements were set to exceed the approximately 35 MW of capacity available at Hydro One's Kent TS by 2020, with additional demand of 20 MW expected to materialize by 2023.

Entegrus, Hydro One, and the IESO took several steps to accommodate these expected near-term requirements. This entailed temporarily including the Kent TS area into the scope of the Windsor-Essex Integrated Regional Resources Plan ("IRRP") work, which was underway in 2019. Traditionally, Kent TS would normally fall into the Chatham-Kent/Lambton/Sarnia resource planning area. Based on the anticipated customer load needs, the IRRP process identified the need for a new Dual Element Spot Network ("DESN") station in Chatham. Entegrus and Hydro One commenced planning for the new station, while also exploring the changes to local protection schemes to better accommodate the near-term capacity requirements.

Subsequently, due to a downturn in the cannabis industry, the agricultural customer retracted its connection application in late 2019, thereby putting the plans of a new TS on hold. Thereafter, another large industrial proponent approached Entegrus with an initial request for 23 MW of incremental connection capacity at Kent TS in two phases. Subsequently, the customer reduced its request down to 7.5 MW – which can be accommodated within Entegrus' existing capacity. Accordingly, based on Entegrus' latest load forecast (discussed in more detail in Section 4.4.5.2.5) there are no incremental transformation capacity additions anticipated for the Chatham area at this time over the Forecast Period. However, these events signal that, at a point in time not yet known, the need to expand

Entegrus capacity at Kent TS will be required. This DSP filing does include System Access investment for a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas in 2023. This planned investment and additional discussion on the potential for a new feeder in Chatham, if (or when) customer demand merits, are covered in more detail in Section 4.

While the impact of the COVID-19 pandemic was initially expected to slow down the pace of load growth, as noted in Section 1.4.6, strong growth continued into 2021. Further, Entegrus' large manufacturing base (predominantly in the General Service > 50 kW and Large Use rate classes in the Southwest region) rebounded relatively quickly once pandemic restrictions were initially relaxed in the summer of 2020.

As noted in Section 0, this DSP balances a stronger investment focus on reliability (System Renewal) and unprecedented customer growth (System Access) in 2020 and 2021 (which is expected to moderate starting in 2022), with an objective of keeping distribution rates affordable for customers. Entegrus does not currently plan for any ICM applications in the 2021-2025 period. However, a situation may evolve in the future that requires Entegrus to file an ICM application in the 2021-2025 period and Entegrus expressly reserves its right to do so if this does occur.

1.4.7.2 System Efficiency

Table 1-3 showcases the kilowatt-hour purchases, deliveries and the associated losses for STEI, Legacy Entegrus and Entegrus over the Historical Period. As the table indicates, at the beginning of the Historical Period (2016), Legacy Entegrus' distribution losses exceeded the provincial industry average of 3.90%, whereas the losses for STEI were below the provincial average. Entegrus notes, this range in the loss factors are attributed to unique service territories that Entegrus originated from. As discussed in Section 1.4, Legacy Entegrus is comprised on 16 individual communities over a non-contiguous geographic area versus legacy STEI which operated within the contiguous St. Thomas community.

Table 1-3: Efficiency of kWh purchased by Entegrus

Year	Description	kWh Losses			
		Total Purchases	Total Delivered	Total Losses	Loss Percent
		(A)	(B)	(C) = (A) - (B)	(D) = (C) / (A)
2016	STEI	290,949,671	280,584,395	10,365,277	3.56%
	Legacy Entegrus	944,029,185	903,683,893	40,345,292	4.27%
	Total Combined	1,234,978,856	1,184,268,288	50,710,568	4.11%
2017	STEI	281,129,576	273,297,623	7,831,954	2.79%
	Legacy Entegrus	923,425,886	889,950,319	33,475,567	3.63%
	Total Combined	1,204,555,462	1,163,247,942	41,307,520	3.43%
2018	Entegrus	1,256,991,995	1,211,940,351	45,051,643	3.58%
2019	Entegrus	1,230,956,720	1,179,530,899	51,425,821	4.18%
2020	Entegrus	1,212,893,013	1,165,448,521	47,444,491	3.91%

The highly embedded and distributed nature of Entegrus' system – particularly the Legacy Entegrus portion, which includes several communities receiving power at lower primary voltages (i.e. 8.0kV) – contributes to relatively high losses within the system. Aging infrastructure and the presence of 4kV and 2.4kV sub-distribution puts additional upward pressure on loss rates. Conversely, it is anticipated that the continued voltage conversion projects have contributed to lower loss rates than would otherwise have occurred; this "lower than otherwise" long-term loss trend is expected to continue as more voltage conversion occurs. Ultimately, in aggregate, annual improvements from conversion are easily overshadowed by other contributing factors (i.e. load shape, power factor, non-technical losses). In the case of the Legacy Entegrus service territory, voltage conversion activities target 4.18 kV distribution feeders built to outdated standards and consisting of assets in deteriorated condition that have been in service since the 1960s. In St. Thomas, voltage conversion activities target legacy feeders operating at an even lower 2.4 kV voltage. Both types of legacy low-voltage feeders and the Municipal Step-Down Stations they emanate from are more susceptible to technical losses than the modern 27.6 kV infrastructure that Entegrus is gradually replacing them with.

It is important to note that system losses are non-linear with system demand and can vary with load profile. As the area converted each year represents a small fraction of the total assets, it is possible for the gains realized from conversion to be overshadowed by other factors. As such, this metric should be viewed as a long-term trend rather than a year-over-year metric.

1.5 Background & Drivers

1.5.1 The Post 2016 DSP Experience (2016-2020)

The replacement of aging infrastructure was a key focus in the 2016 DSP process. Ultimately, in the associated Cost of Service application (EB-2015-0061) and the finalized 2016 DSP, Entegrus balanced System Renewal with keeping customer rates affordable.

Since 2016, Entegrus has used both qualitative assessments and quantitative metrics to monitor the quality of its capital expenditure plans, the efficiency with which its plan was implemented, and the extent to which its planning objectives were being met. This information, some of which is summarized below, has been used by Entegrus 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 2021-2025 DSP.

In August 2016, two Legacy Entegrus line staff suffered injuries while changing a switch in the community of Strathroy. While both employees later recovered from their injuries, the accident further underscored the importance of safety and prompted a thorough re-evaluation of Entegrus' safety systems and processes, as well as further company-wide emphasis on the Entegrus IHSA COR safety certification. The overall internal re-evaluation identified the need to commence a 3-year project to update distribution system maps across the then 16 Entegrus communities. While GIS services were previously a mix of in-house and third-party service provider services, the enhanced mapping requirements triggered the need to bring GIS in-house to fully meet industry infrastructure requirements and required the hiring of additional skilled GIS staff. Simultaneously, it was identified that the Control Room required updates to enable the digital transformation from paper-based system mapping. Digital maps enable more timely updates as the system experiences growth, or conversion work occurs, thus facilitating safer operations in real time. The update also allowed for modernization of Control Room processes, improving the accuracy, ease of access and visibility of a live system view to our 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. In Q2 of 2021, a second full-time System Operator was added to the staff, complemented by several qualified backup Operators.

As part of the modernization process, field staff embarked on simultaneously mapping and inspecting the system – ultimately "touching" the entire system. This included infrared, visual and drill-based pole inspection, transformer inspection and underground cable verification. These processes identified that portions of the system had aged and degraded beyond the expectation of the previous DSP. Additional field asset inspection by engineering validated these assessments and confirmed there was need for prompt remediation. While Entegrus continues to do visual inspections of its poles using its historical report-by-exception methodology, management also instituted a resistograph "pole-drill" based inspection program. This program inspects a sample group of poles annually to ensure that the most degraded assets are prioritized for immediate attention, while also building a statistical model for overall population health. Several submersible transformers failed unexpectedly during this timeframe, which led to a re-evaluation of operating practices and the commencement of phase-out of submersible transformers (migrating these locations to pad-mounted equipment).

Simultaneously, starting in 2017, the overall duration and frequency of outages across the 16 Legacy Entegrus (Entegrus-Main) communities significantly deteriorated, indicating that sustained outages were on average occurring more frequently and lasting longer. This trend was driven by aged infrastructure, which led to a notable increase in Defective Equipment outages (see Table 2-10). Through 2016-2018, additional engineering resources were hired to assist with enhanced System Renewal and reliability analysis, and enhancements to outage tracking and investigation practices were also implemented. These additional resources also assisted with smart grid deployment over the 2016-2020 period to manage the impact of outages through automatic restoration and/or minimization of affected areas. These automation investments, entailing a mix of reclosures and automated load break switches, successfully mitigated various loss of supply events as well as providing direct benefits to Entegrus' system. Ultimately, this resulted in a combined 18,000 of avoided Customer Hours of Interruption ("CHI") between 2017 and 2020. While overall reliability deteriorated further in 2018, these investments assisted with mitigation of what would have otherwise occurred.

Additional asset condition assessment work was predominantly performed in 2019 in support of this DSP filing. This work was conducted with the assistance of third-party engineering and analytics firm METSCO Energy Solutions ("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 Asset Condition Assessment ("ACA") prepared by METSCO and shown as Attachment C. In the ACA, METSCO delineated 14 categories and subcategories of assets, covering the entire Entegrus 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": Wooden Poles (25%), Submersible Transformers (22%), Overhead Transformers (20%), Substation Ground Grids (43%) and EPR/XLPE Cable (25%). While this is an indicator that Entegrus has successfully leveraged asset lives, it also indicates a need for significant reinvestment to maintain system integrity. In its report conclusion, METSCO recommended that "*maximum feasible resources be dedicated to active System Renewal work*" (see Attachment C, page 64).

Associated risk-based analyses were then undertaken to understand the impact of system condition on customer reliability over the Forecast Period and beyond. This included analysis of investment prioritization of renewal vs. automation across different spending and reliability levels. This corroborated that the deterioration in Entegrus' reliability measures required timely and proactive intervention to maintain reliability and start to slow, or halt, the reliability deterioration trend before it becomes irreversible. Thereafter, work practice changes due to the pandemic allowed management to ramp System Renewal focus in 2020, as well to focus more on maintenance as seen in Section 3.4.

While the above dynamics were occurring, the City of St. Thomas experienced unprecedented residential growth, particularly through 2020 and 2021. This was also seen in the Entegrus' Northeast region communities of Strathroy and Mt. Brydges, as well as Chatham in the Southwest region. These trends are evident in Table 1-1.

With the increase in customer-driven System Access requests, as well as the continued growth of fibre-to-the-home infrastructure requests, Entegrus' reliance on contractors to work on overhead and underground systems is increasingly important. Further deployment of third-party construction contractors commenced in 2020 to enhance scalability and redundancy of the execution of the operational work program moving forward.

1.5.2 Project Drivers for 2021-2025

Table 1-4 below captures the key investment drivers for capital projects and programs comprising this DSP. This includes the lessons learned from the 2016-2020 experience and accordingly, the notable increase in System Renewal investment continues through the Forecast Period. Consistent with the Filing Requirements, the drivers are segmented across the four major DSP Investment Categories and are defined in the manner consistent with examples provided in the Chapter 5 Filing Requirements. In the event where a program involves drivers related to different Investment Categories, the investment is assigned to the Category related to the trigger driver. Please see Section 4 of this DSP for the description of additional drivers applicable to each project.

Table 1-4: Entegrus Key Drivers for DSP Projects

Category	Driver	Representative Programs & Projects	$ 000's 2021 Plan	2022 Plan	2023 Plan	2024 Plan	2025 Plan
System Access	Customer Requests	Customer Conns - Residential	$3,753	$2,562	$2,604	$2,191	$2,235
		Customer Conns- Comm/Industrial	$106	$108	$110	$112	$114
		Commercial & Industrial Rebuild	$327	$333	$340	$347	$354
		Edgeware Capacity Enhancements	$0	$0	$1,700	$0	$0
	Third Party Infrastructure Requirements	Third Party Attachments	$587	$346	$300	$306	$312
	Mandated Service Obligations	Delta-Wye Service Conversions	$253	$100	$80	$60	$0
		Engineering Support Capital	$765	$780	$796	$812	$828
		Miscellaneous	$77	$79	$81	$82	$84
	Contributed Capital		-$3,367	-$2,300	-$2,356	-$2,413	-$2,471
	Subtotal		**$2,499**	**$2,008**	**$3,654**	**$1,496**	**$1,455**
System Renewal	Functional Obsolescence, Substandard Performance & Failure Risk	Voltage Conversion	$3,201	$3,301	$3,443	$4,862	$4,827
	Failure & Failure Risk	Transformer Replacement	$436	$445	$428	$436	$445
		Pole Replacement	$506	$586	$597	$609	$622
		Critical Defect Replacements	$322	$375	$383	$391	$378
	Functional Obsolescence	Metering Renewal	$1,394	$1,556	$1,587	$1,619	$1,632
	System Capital Investment Support	Operations Support Capital	$776	$791	$807	$823	$840
		Emergency Response	$457	$466	$475	$485	$494
		Miscellaneous	$146	$149	$152	$155	$158
	Subtotal		**$7,238**	**$7,669**	**$7,872**	**$9,380**	**$9,395**
System Service	System Reliability & Efficiency	System Automation	$110	$142	$145	$1,085	$643
		System Modernization	$436	$537	$548	$559	$570
		System Reinforcement	$350	$128	$131	$133	$136
		Metering Upgrades	$65	$66	$68	$69	$70
		Miscellaneous	$102	$94	$96	$98	$100
	Subtotal		**$1,063**	**$968**	**$987**	**$1,944**	**$1,519**
General Plant	System Capital Investment Support	Rolling Stock	$805	$841	$908	$925	$943
		Capital Equipment	$209	$213	$217	$222	$226
	Non-System Physical Plant	Building Improvement & Sustainment	$176	$199	$203	$207	$211
		IT Hardware & Software	$480	$550	$560	$560	$565
		Miscellaneous	$305	$247	$200	$207	$205
	Subtotal		**$1,974**	**$2,051**	**$2,088**	**$2,121**	**$2,150**
Grand Total			**$12,775**	**$12,696**	**$14,601**	**$14,942**	**$14,520**

The following is Entegrus' interpretation of the scope and nature of the four DSP Investment Categories.

System Access

Enhancements and modifications to the distribution system that Entegrus is obligated to perform in response to requests for access to electricity services via its system, or for system modifications (e.g. asset relocations) to enable other objectives of a customer or a third party. This category also includes capitalized engineering costs related to planning preparations related to customer and/or third-party requests.

System Renewal

Replacement and/or refurbishment of aged, deteriorating, or failed system assets to maintain the ability to provide electricity service in a safe and reliable manner. Where economic, and/or driven by evolution of technical standards, System Renewal activities may also entail upgrades of capacity, design, remote operability, or other operational capabilities such as metering renewal, along with replacement of these various assets. This category also includes capitalized supervisory and emergency response costs incurred while rectifying system outages and/or preparing and executing planned renewal work.

System Service

Modifications to Entegrus' distribution system, supporting equipment, and/or upstream transmission and distribution assets to ensure long-term service continuity and continued ability to meet regular and emerging customer service requirements and operational objectives. Includes capital costs incurred in monitoring system operation, and investments in new technology and asset management analytics that yield system efficiency, reliability, and other types of benefits.

General Plant

Replacement, enhancements, or additions to Entegrus' assets that are not themselves part of the electric distribution system but support its day-to-day operation, and health, safety and efficiency of the Entegrus staff. This category includes investments in land and buildings, tools and construction and maintenance equipment, rolling stock, and Information Technology ("IT") hardware and software.

1.5.3 Asset categorization changes since from the last DSP Period

Entegrus has made a single change to the mapping of its projects to the investment categories versus Legacy Entegrus' 2016 DSP. Entegrus has moved Engineering Support Capital from System Renewal to System Access to between align the engineering activities with drivers of those activities.

Additionally, Entegrus has updated its Project listing to better align the projects between Legacy Entegrus and the former STEI. This is further discussed in Section 4.4.

2 DISTRIBUTION SYSTEM PLAN (5.2)

Filing Requirement 5.2: Distributors are encouraged to organize the required information using the section and subsection headings indicated from here onwards. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall provide a table that clearly cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in these filing requirements. Distributors are also encouraged to structure the application so that all DSP appendices and supporting materials are included after the main DSP body text, to facilitate review.

The DSP's duration is a minimum of ten years in total, comprising of an historical period and a forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year.

Section 2 describes the key inputs Entegrus relied on in developing this DSP and provides an account of their evolution over the Historical Period. Section 2.1 entails an overview of the DSP's key elements, including the following topics:

- A summary of changes to the AM process since the last (2016-2020) DSP filing;
- A summary of customer preferences underlying the Plan; and
- A description of activity areas expected to generate cost efficiencies in 2021-2025.

Building on these plan fundamentals, Section 2.2 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 2021-2025 DSP preparation process.

Moving to the elements of the DSP's execution, Section 2.3 addresses Entegrus' performance measurement and continuous improvement tracking framework, including the summary of results from the last reporting period. Finally, Section 2.4 provides an account of efficiencies and other improvements that have arisen as a result of the smart meter implementation.

2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

This section discusses the key elements comprising the DSP, including the planning frameworks supporting the Plan, the sources of expected cost efficiencies, the period covered by the DSP, and the vintage of the information that the DSP relies on. The section also details the most material changes to Entegrus' AM processes and addresses the future events (both within and outside of the utility's control) that may result in reconsideration, rescoping or reprioritization of investment plans for the 2021-2025 Forecast Period.

2.1.1 Key Elements of the DSP (5.2.1a)

Filing Requirement 5.2.1a: Key elements of the DSP that affect its rate proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

Entegrus' DSP is a planning document backed by the policies, processes and decision-making frameworks that are in place to maximize the likelihood of management's capital investment decisions achieving the targeted investment outcomes in a cost-effective manner. The tables on the following pages present the capital expenditures by investment category and the system Operations and Maintenance (“O&M”) costs for the Predecessor Historical Period (2016-2017), the Historical Period (2018-2020) and the Plan Period (2021-2025).

Table 2-1: Predecessor Historical Period Capital Expenditures ($000’s)

Line No.	Description	Legacy Entegrus			STEI			Combined		
		Plan	Actual	Variance	Plan	Actual	Variance	Plan	Actual	Variance
1	**2016**									
2	System Access	$1,788	$2,157	$369	$200	$812	$612	$1,988	$2,969	$981
3	System Renewal	$3,749	$4,069	$320	$1,590	$1,554	-$36	$5,339	$5,624	$284
4	System Service	$1,192	$889	-$303	$50	$25	-$25	$1,242	$914	-$328
5	General Plant	$1,519	$1,183	-$335	$386	$162	-$224	$1,905	$1,345	-$559
6	**Total Expenditure**	**$8,249**	**$8,298**	**$50**	**$2,226**	**$2,553**	**$327**	**$10,475**	**$10,852**	**$377**
7	Capital Contributions	-$375	-$846	-$471	-$100	-$654	-$554	-$475	-$1,501	-$1,026
8	**Net Capital Expenditures**	**$7,874**	**$7,452**	**-$422**	**$2,126**	**$1,899**	**-$227**	**$10,000**	**$9,351**	**-$648**
9	System O&M	$3,055	$3,030	-$26	$1,346	$1,128	-$218	$4,402	$4,158	-$244
10	**TOTAL**	**$10,929**	**$10,481**	**-$448**	**$3,472**	**$3,027**	**-$445**	**$14,401**	**$13,509**	**-$892**
11	**2017**									
12	System Access	$1,758	$2,271	$512	$200	$1,643	$1,443	$1,958	$3,914	$1,955
13	System Renewal	$3,852	$3,763	-$88	$1,530	$271	-$1,259	$5,382	$4,035	-$1,347
14	System Service	$1,244	$1,643	$399	$50	$24	-$26	$1,294	$1,667	$373
15	General Plant	$1,234	$1,826	$592	$408	$322	-$86	$1,642	$2,148	$507
16	**Total Expenditure**	**$8,088**	**$9,503**	**$1,415**	**$2,188**	**$2,261**	**$73**	**$10,276**	**$11,764**	**$1,488**
17	Capital Contributions	-$375	-$549	-$174	-$100	-$1,395	-$1,295	-$475	-$1,944	-$1,469
18	**Net Capital Expenditures**	**$7,713**	**$8,954**	**$1,241**	**$2,088**	**$866**	**-$1,222**	**$9,801**	**$9,820**	**$19**
19	System O&M	$3,043	$2,918	-$125	$1,375	$998	-$376	$4,418	$3,916	-$502
20	**TOTAL**	**$10,756**	**$11,872**	**$1,116**	**$3,463**	**$1,864**	**-$1,599**	**$14,219**	**$13,736**	**-$482**

Table 2-2: Historical Period Capital Expenditures ($000's)

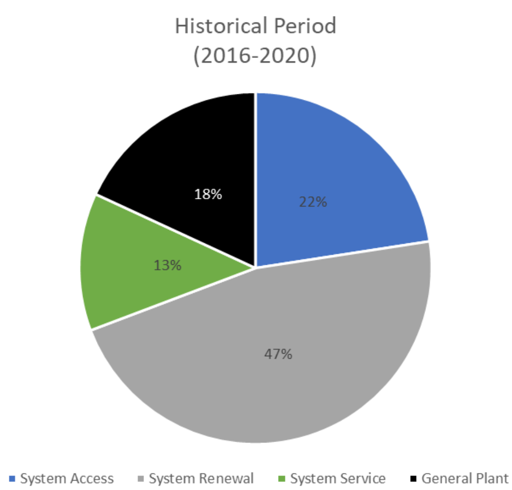
Line No.	Description	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		Plan	Plan	Plan	Actual	Variance
1	**2018**					
2	System Access	$1,779	$200	$1,979	$4,169	$2,190
3	System Renewal	$4,154	$1,520	$5,674	$4,518	-$1,156
4	System Service	$1,076	$100	$1,176	$1,213	$37
5	General Plant	$1,023	$165	$1,188	$1,973	$786
6	**Total Expenditure**	**$8,032**	**$1,985**	**$10,017**	**$11,874**	**$1,857**
7	Capital Contributions	-$375	-$100	-$475	-$1,454	-$979
8	**Net Capital Expenditures**	**$7,657**	**$1,885**	**$9,542**	**$10,420**	**$878**
9	System O&M	$3,095	$1,885	$4,980	$3,946	-$1,034
10	**TOTAL**	**$10,752**	**$3,770**	**$14,522**	**$14,366**	**-$156**
11	**2019**					
12	System Access	$1,800	$200	$2,000	$5,719	$3,719
13	System Renewal	$4,131	$1,560	$5,691	$4,592	-$1,099
14	System Service	$1,083	$100	$1,183	$1,223	$40
15	General Plant	$1,036	$122	$1,158	$2,383	$1,225
16	**Total Expenditure**	**$8,050**	**$1,982**	**$10,032**	**$13,917**	**$3,885**
17	Capital Contributions	-$375	-$100	-$475	-$3,357	-$2,882
18	**Net Capital Expenditures**	**$7,675**	**$1,882**	**$9,557**	**$10,559**	**$1,002**
19	System O&M	$3,153	$1,433	$4,586	$4,341	-$246
20	**TOTAL**	**$10,828**	**$3,315**	**$14,143**	**$14,900**	**$757**
21	**2020**					
22	System Access	$1,821	$200	$2,021	$6,245	$4,224
23	System Renewal	$3,769	$1,560	$5,329	$6,121	$792
24	System Service	$1,141	$100	$1,241	$1,731	$490
25	General Plant	$1,106	$122	$1,228	$1,805	$577
26	**Total Expenditure**	**$7,836**	**$1,982**	**$9,818**	**$15,902**	**$6,084**
27	Capital Contributions	-$375	-$100	-$475	-$2,726	-$2,251
28	**Net Capital Expenditures**	**$7,461**	**$1,882**	**$9,343**	**$13,176**	**$3,833**
29	System O&M	$3,207	$1,433	$4,640	$3,963	-$677
30	**TOTAL**	**$10,668**	**$3,315**	**$13,983**	**$17,139**	**$3,156**

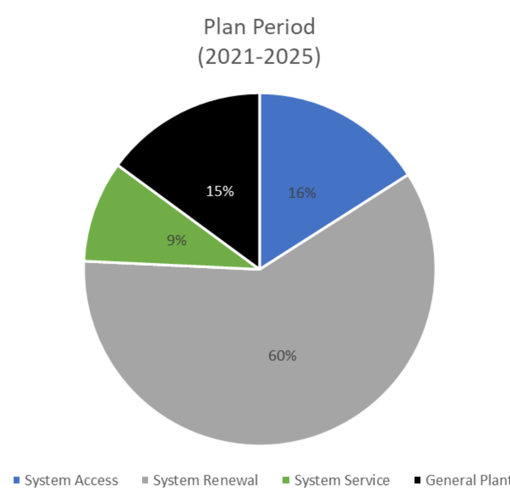
Table 2-3: Forecast Period Capital Expenditures ($000's)

Line No.	Description	2021	2022	2023	2024	2025
1	System Access	$5,867	$4,308	$6,010	$3,909	$3,926
2	System Renewal	$7,238	$7,669	$7,872	$9,380	$9,395
3	System Service	$1,063	$968	$987	$1,944	$1,519
4	General Plant	$1,974	$2,051	$2,088	$2,121	$2,150
5	**Total Expenditure**	**$16,142**	**$14,996**	**$16,957**	**$17,355**	**$16,991**
6	Capital Contributions	-$3,367	-$2,300	-$2,356	-$2,413	-$2,471
7	**Net Capital Expenditures**	**$12,775**	**$12,696**	**$14,601**	**$14,942**	**$14,520**
8	System O&M	$4,745	$5,185	$5,328	$5,476	$5,628
9	**TOTAL**	**$17,520**	**$17,881**	**$19,929**	**$20,418**	**$20,148**

The charts below showcase the relative breakdown of total anticipated capital expenditures over the Plan Period across the major investment categories. For comparison, it also includes the aggregate allocation by category over the Historical Years (using actual results). The Historical expenditures consolidate the Legacy Entegrus and STEI spend for ease of presentation. System O&M is further described in Section 3.4.

Figure 2-1: Planned Capital Investment by Category





As the above figure and table indicate, in comparison to the Historical Period, the Plan Period capital expenditures are more heavily weighted toward System Renewal. This is consistent with the determination that portions of the system have aged and degraded beyond the expectation of the previous DSP, as detailed by the key asset classes assessed as being in “Very Poor” condition in the ACA included as Attachment C, as well as the associated deterioration of reliability measures starting in 2017. See Section 1.5.1 for a more detailed description of these dynamics.

Overall, the DSP is a product of Entegrus' consideration of multiple inputs that include internal analytical work, external collaborative and consultative engagements, and incorporation of planning priorities articulated by relevant regional and provincial entities. Among others, these inputs include:

- Regional and Provincial Growth Plans;
- IESO Regional Planning outputs for the Planning Regions that Entegrus territory traverses;
- Known municipal and regional infrastructure projects requiring asset relocation;
- Entegrus Asset Management Strategy;
- Performance targets (Distributor Scorecard and Internal KPI targets);
- Insights obtained through Customer Engagement Work;
- Provincial energy policy announcements;
- Entegrus' operating data and insights derived over the Historical Period.

Relying on its Asset Management ("AM") and capital program planning tools and processes, Entegrus incorporated the above-noted inputs into the 2021-2025 investment work program. As with every Entegrus planning document, the 2021-2025 work program is grounded in its Strategic Values Framework, namely Safety, Inspired and Empowered People, Customer and Community Focus, Operational Excellence, and Sustainable Growth (See Section 1.4.4). Applied to Entegrus' specific strategic and operational circumstances, the Corporate Values represent the following key Forecast Period objectives:

- Managing the reliability impact of Entegrus' assets, with emphasis on System Average Interruption Duration Index ("SAIDI"), which has recently deteriorated simultaneous to the determination that portions of the Legacy Entegrus distribution system have aged and degraded beyond original expectation. SAIDI is emphasized given the non-contiguous and geographically dispersed nature of the system.
- Ensuring that planning and execution of the 2021-2025 capital work program entrenches and consolidates the use on common tools and processes established in the course of Entegrus' amalgamation with the former STEI.
- Modernizing and standardizing the Entegrus system design and operational capabilities from their currently heterogenous mix of voltages, materials and equipment configurations that stems from the history of amalgamations.
- Leveraging recent enhancements to Entegrus' AM capabilities to deliver a work program that is reliant on data-driven analysis of asset intervention economics and is proactively set up to capture incremental planning insights for continuous improvement.

This DSP document provides multiple examples of the ways in which Entegrus integrated these objectives into its asset management analytics and capital planning considerations. Overall, Entegrus believes that this DSP represents a robust and efficient blueprint for furthering its strategic objectives over the Plan Period. Entegrus is confident that this iteration of the DSP presents a clear example of focussed continuous improvement, building on the groundwork laid out in the Historical Period and setting out the improvement objectives for the Plan Period.

To provide further context to the planning circumstances that shaped the DSP production dynamics, the following subsections describe some of the most significant operating concerns facing Entegrus asset planners.

2.1.1.1 Impact of the Entegrus/STEI Amalgamation

Entegrus' April 2018 amalgamation with STEI represents an important planning consideration for the 2021-2025 Forecast Period in several respects.

At the time of requesting the OEB's approval, Entegrus and STEI estimated that by 2023 the transaction would enable between $1.2 - $1.4 million in annual OM&A cost savings and another $0.2 - $0.3 million in annual reductions to capital expenditures.[6] Please see Section 3.3.5 for additional information on capital expenditures. The applicants also opted for an eight-year Deferred Rebasing Period, set to conclude in 2026. Accordingly, this is a stand-alone DSP and is not related to a rebasing application.

Drawing on its significant post-M&A integration experience gained over the past decade, Entegrus has substantially completed the integration-related project work across all major utility areas. This includes completion of the following key milestones:

- Development of a new organizational structure, staffing plan and departmental mandates;
- Consolidation of the Operational Health and Safety Management Framework and the consistent establishment of IHSA COR across the company;
- Set-up of the financial record keeping framework to meet all reporting obligations;
- Integration of Information Technology and field communications infrastructure;
- Migration of STEI customers onto Entegrus' Customer Care and Billing platform;
- Consolidation of the call centre phone technology, operating protocols and training;
- Integration of the predecessors' AMI assets and operations;
- Consolidation of Control Room functions including communications, procedures, SCADA and operating maps; and
- Consolidation and rollout of a harmonized Conditions of Service.

At this juncture, all major tasks associated with ensuring smooth, safe, and consistent utility operations across the expanded service territory have now been completed. A major component of the integration work were the modifications to the St. Thomas facility for the consolidation with the Strathroy work centre that has recently taken place. In September 2020, Strathroy Customer Service personnel were transferred to the St. Thomas operations centre and integrated with St. Thomas personnel. In 2021 Q4, a similar consolidation of the remaining Strathroy Operations (Lines and Metering) personnel will occur. Control room functionality was merged in February 2020, bringing the safety and coordination benefits of having operations Control Room coverage in the St. Thomas territory. Entegrus was able to utilize its newly modernized Control Room to serve the expanded service territory without significant additional investment. Other operational integration activities included cross-training and service area-specific subject matter familiarization activities.

[6] MAAD Application, EB-2017-0212, Dated July 21, 2017, Section 5.2.1, PDF Page 32

Another important integration task completed while preparing this DSP was the review and reconciliation of the Historical Period capital expenditures across the two predecessors. Aside from completing the prescribed variance analysis provided in Section 4.4, the completion of STEI's capital variance analysis enabled the integration of Entegrus Finance, Regulatory and Planning staff to get a more nuanced understanding of the two predecessors' respective investment planning assumptions and available data.

As described in more detail in Section 2.1.6, Entegrus made significant progress with integration-related activities within the Asset Management and Capital Planning functional areas. Among the critical integration tasks that enabled preparation of an integrated DSP were:

- Extension of Entegrus' SCADA capabilities to the STEI system;
- Harmonization of STEI's asset and connectivity data with Entegrus' GIS and CYME systems used to model and simulate Entegrus' distribution system; and
- Preparation of an integrated Asset Condition Assessment ("ACA") covering both service areas.

Impact on this DSP

A challenge of investment pacing and prioritization across a recently amalgamated service area is the impact of historically independent asset management strategies, planning assumptions and operational inspection and record keeping practices. While Entegrus completed an integrated ACA[7] covering both predecessors' service territories, the analytical work relied on two independent sets of data gathered by predecessors who either collected different types of information or relied on independently developed and calibrated condition evaluation scales. Until all consolidated assets undergo inspection / testing using a consistent approach over the next three years, Entegrus' AM staff will periodically monitor the information collected across the system and engage the operations personnel from all operating centres to help entrench a common approach to visual assessments. Additional learning will occur.

2.1.1.2 Key Issue: Legacy Low-Voltage Infrastructure

Like many other Ontario distributors serving mature municipal areas, Entegrus' service territory contains a significant volume of legacy low-voltage distribution infrastructure comprised of both overhead and underground lines and municipal step-down transformer stations built to outdated design standards. Most of this legacy infrastructure (by length) operates at 4.16 kV voltage and is located in Chatham, Strathroy, Blenheim, and Ridgetown, with a pocket of 2.4 kV infrastructure located in St. Thomas. Entegrus' capital investment portfolio has included a Voltage Conversion program for more than 10 years, targeting replacement of legacy assets at high risk of failure and upgrading them to modern 27.6 kV feeders, characterized by more compact design, higher resilience to inclement weather, lower technical losses and higher loading capacity. Post-merger at the time of this DSP, Entegrus has 21 remaining substations, which will be the focus of conversion throughout the Plan period and beyond.

[7] See Section 0 and Attachment C for the ACA results

Upon converting all 2.4 / 4.16 kV lines emanating from a single area step-down Municipal Station ("MS"), Entegrus decommissions the stations themselves, as their step-down function becomes redundant. Among the benefits of modernizing the distribution system, standardization of equipment, additional feeder capacity and other benefits, the conversion work drives reductions in technical losses discussed as in Section 1.4.7. By decommissioning the MS infrastructure before its assets like station transformers and circuit breakers warrant replacement, Entegrus is also creating long-term capital savings for its customer base. To reduce the financial impact of the decommissioning work, Entegrus offsets the cost of this work through the subsequent sales of land parcels that becomes vacant and revenues from equipment scrap sales. Accordingly, progressive conversion and decommissioning of substation assets forms a major facet of Entegrus' Asset Management strategy. Entegrus initially planned to decommission up to four substations in the Forecast Period. The customer engagement process determined that instead, a faster pace should be undertaken and five substations should be decommissioned in 2021-2025. See Section 4.1.3.2 for more details on these customer engagement results.

Impact on this DSP

Feeder conversion work remains a key focus of Entegrus' investment program throughout the Forecast Period. The addition of 21 km of legacy 2.4 kV delta-configured overhead infrastructure in the former STEI service area, the total amount of future conversion work for Entegrus to plan for and prioritize against other System Renewal investment drivers has increased. Although the amalgamation also brings incremental capital funding and work execution capacity to Entegrus' resource pool, the increased complexity in potential combinations of conversion work volumes, locations and pacing options will require management to conduct robust planning throughout the 2021-2025 Forecast Period and beyond. With an increase to the overall volume of conversion candidates, balancing the planned and near-term work will require even more ongoing attention and managerial flexibility.

The existence of large volumes of legacy low-voltage infrastructure will require creative planning to complete given the type of conversion work increasingly facing Entegrus in the future. While the bulk of historical conversions targeted the overhead 4.16 kV system, the approximately 347.4 km of low-voltage underground circuits remain to be converted. The strategy of prioritizing overhead conversion work is driven by throughput considerations and the expected impact on reliability. On a per-unit basis, overhead work costs substantially less than underground conversion, meaning more work can be typically done for the same budget. Moreover, rebuilding overhead lines not only reduces the probability of defective equipment outages, but also makes the system more resilient to weather and foreign interference.

2.1.1.3 Key Issue: Service Territory Implications

Entegrus' service area of 132 km² consists entirely of urban territory and ranks 32nd in size among Ontario utilities. While it is only two places above the provincial median in service territory size, a distinguishing and operationally consequential characteristic of Entegrus stems from the fact that it is made up of 17 independent municipal distribution systems dispersed across a 5,600-km² geographic area. The driving distance and time between the northernmost and southernmost communities in

Entegrus' service area amount to approximately 170 km and two hours, respectively. While some of the municipal systems draw power from the low voltage side Hydro One's transmission stations, others are embedded within Hydro One's distribution service territory.

The implication of Entegrus' non-contiguous and geographically dispersed service territory is that outage response times may be impacted, especially for communities that are further removed from Entegrus' operating centres in Chatham and St. Thomas, (following the upcoming incorporation of the former Strathroy personnel into the latter in 2021 Q4). A related factor affecting smaller Entegrus communities connected downstream of the supplier's distribution system are Loss of Supply-driven outages. Successful collaboration with the upstream supplier has recently resulted in augmentation of supply reliability via the installation of automated switching. This has included working with the upstream supplier's protection and control personnel regarding the installation of circuits in Tilbury and Wallaceburg that have combined to help avoid nearly 18,000 Customer Hours Interrupted ("CHI") since being installed in 2017. Entegrus will continue to look for opportunities to work with the upstream supplier in this regard in communities where multiple supply point redundancies exist.

Impact on this DSP

Taking steps to reduce the System Average Interruption Duration Index ("SAIDI") and Loss of Supply - caused outage statistics were key planning priorities in the 2016 DSP and have now taken even more importance and focus, as described in Section 1.5.1. While the sections that follow describe examples of improvements on both fronts related to specific projects and/or communities, the utility-wide outage duration performance (with and without Loss of Supply and Major Event Day adjustments) remains the utmost priority.

To address this issue, Entegrus' 2021-2025 System Renewal and certain parts of System Service capital work program are heavily geared towards addressing the outage duration. Leveraging Entegrus' recent enhancements in AM analytics discussed in Section 2.1.6, the 2021-2025 work program seeks to direct asset replacements towards the parts of the system posing the greatest amount of system risk and potential to enhance Entegrus' reliability performance over the coming years.

As Entegrus has crews stationed in its Southwest and Northeast operating centres, driving time is an important planning consideration. A key part of detailed annual work planning thus involves optimizing the project locations and sequencing in a way that maximizes the active construction throughput of Entegrus crews and contractor crews, while addressing the most pressing asset needs first.

2.1.1.4 Key Issue: Capacity Planning Post COVID-19 Pandemic

The COVID-19 pandemic has challenged Ontario's, Canada's and the global economy in an unparalleled manner, leading to extreme volatility in the global equity markets, curtailment of personal consumption levels, and widespread layoffs across multiple sectors of the economy. Southwestern Ontario was not an exception, with accommodation, food services, culture, and retail industries being among the most affected. As noted above, Entegrus' large manufacturing base (predominantly in the General Service > 50kW and Large Use rate classes in the Southwest region) rebounded relatively quickly once Ontario pandemic restrictions were initially relaxed in the summer of 2020.

Impact on this DSP

The uncertain pace of the economy's recovery within Entegrus' service territory represents a planning uncertainty with respect to most System Access and System Service investments driven by current or anticipated customer demand. Since the development of this DSP coincided with the peak of the COVID-19 pandemic, Entegrus planners considered the potential for greater deviations from the historical connection work demand, especially as employers in the province move towards more employee work from home arrangements. Beyond the unprecedented residential growth in St. Thomas, as well as higher growth Northeast region communities of Strathroy and Mt. Brydges, management is aware of an "out-migration" trend[8] arising from the pandemic, whereby former residents of the GTA are migrating into the Entegrus service territory (particularly to Chatham).

In the design phase of this DSP, it was anticipated that due to the pandemic, the above-described growth would slow and then decline to lower than Historical Period levels in 2022-2025. This expectation was reinforced when many developers put System Access requests on hold between March 2020 and June 2020. However, when Ontario pandemic restrictions eased in the summer of 2020, growth surged again, particularly in St. Thomas, Strathroy, Mount Brydges and Chatham. This surge has continued into September 2021, such that management updated this DSP filing to adjust 2022-2025 System Access by an aggregate increase of $3M prior to filing of this DSP in September 2021, in order to reflect a more moderate growth outlook. This moderate growth outlook remains consistent with the anticipated end of pandemic-related housing trends, as well as constraints to the supply of available development land within established service territory boundaries.

2.1.2 Overview of Customer Preferences and Expectations (5.2.1b)

Filing Requirement 5.2.1b: An overview of how projects or initiatives address customers' preferences and expectations.

A key goal for Entegrus is to ensure that its investment planning strategy and work execution practices reflect the needs and preferences of its growing customer base. Beyond the multiple other modes of ongoing customer interaction and engagement described in Section 2.2.2, and more specifically in Section 2.2.2.2, Entegrus conducted two additional phases of customer engagement specifically related to this DSP.

Phase 1 (March 2020)

In the early stages of preparing this 2021-2025 DSP filing, Entegrus identified that a critical advance design determinant was the anticipated penetration levels of electric vehicle ("EV") and distributed generation within the planning horizon. The need for this determination was based on ongoing industry

[8] See National Post, January 25, 2021, https://nationalpost.com/news/canada/its-called-out-migration-and-canadas-bigger-cities-are-bearing-the-brunt

speculation that rapid pace of EV and distributed generation adoption may warrant investments in advanced real-time grid monitoring and balancing technologies.

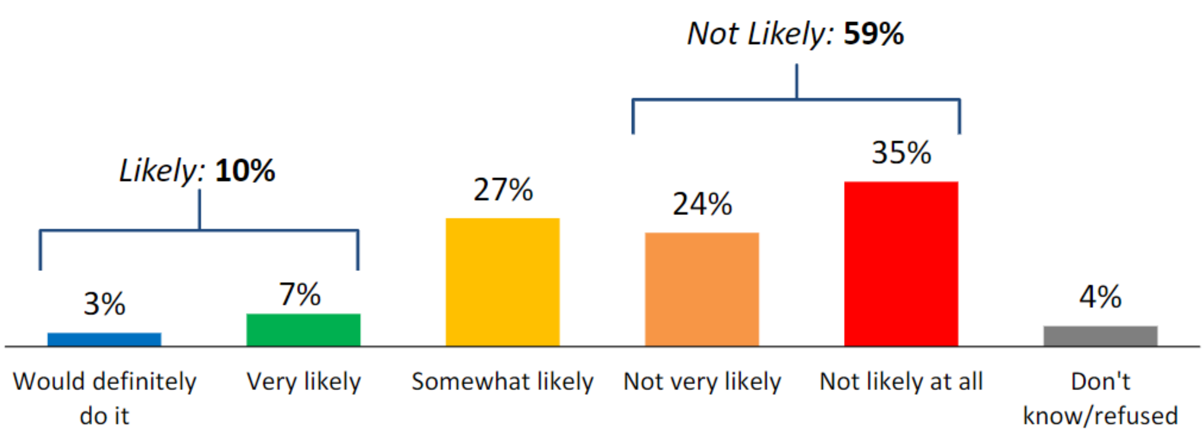
Accordingly, while conducting a telephone-based Public Safety Awareness survey (see Attachment A) with public opinion research and consultation firm Innovative Research in early March 2020, Entegrus asked respondents additional DSP-oriented questions. These additional DSP planning questions aimed to understand customer interest and intention for EV and self-generation technologies and gauge the pace and scale of these being adopted across Entegrus' service territory – today and into the future. Since a significant penetration level of either or both types of technologies will challenge the operating capabilities of most distribution systems, Entegrus could be required to procure various potential grid management capabilities to accommodate new use types.

This survey is considered as Phase 1 of Entegrus customer engagement activities specific to this DSP and was conducted by Innovative Research via telephone between March 2, 2020, and March 16, 2020, among 600 randomly selected Ontario residents, 18 years or older, currently residing in Entegrus' service territory. Of the respondents, 458 customers were eligible to complete the DSP-oriented questions. The sample was weighted by age, gender and region using the latest Statistics Canada Census data to reflect the actual demographic composition of the adult population residing in the Entegrus service territory. After weighting a sample of this size, the aggregated results are considered accurate to within ±4.6%, 19 times out of 20.

All references to Attachment A below refer to the second part of the survey report regarding the custom questions about EV's and self-generation.

The survey showed that 91% of customer respondents own or lease a vehicle, and of those, only 1% drive an EV (see Attachment A, Part II, page 9). Of those who own or lease a vehicle, only 17% intend to replace their vehicle within the next two years (see Attachment A, Part II, page 10). These questions established key context for the penultimate question, related to how likely customers were to buy or lease an electric vehicle when the time comes to replace their current vehicle (see Attachment A, Part II, page 11).

Figure 2-2: Customer Engagement Results – "How likely would you say you are to buy or lease an electric car when it's time to replace your current one?"



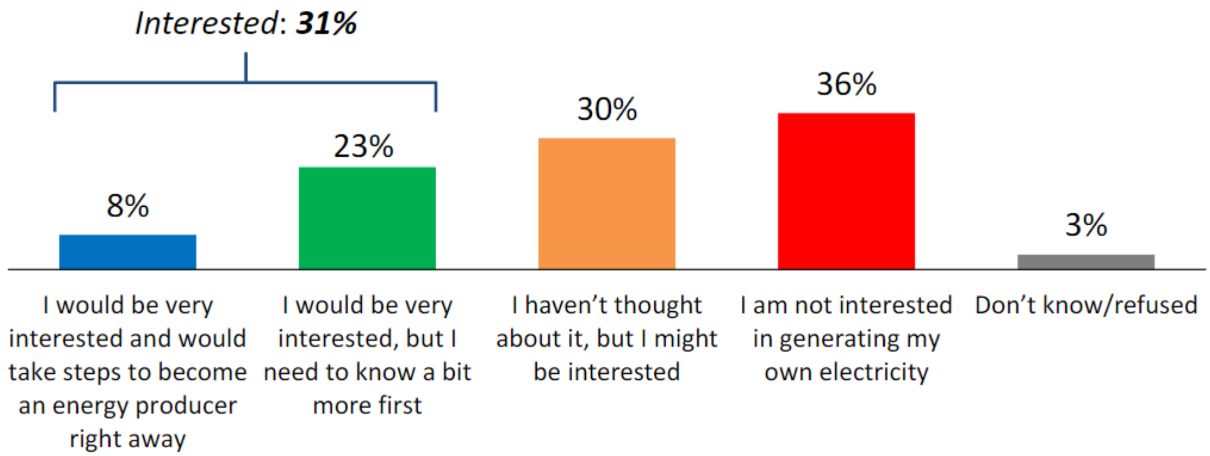
It was illuminating, as shown in the figure above, that only 10% of customers indicate that they are likely to choose an EV for their next vehicle replacement. It was therefore concluded that a slow adoption of EVs is both a result of relatively low projected demand for automobiles (in general) and limited demand for EVs (in particular) (see Attachment A, Part II, page 2).

Given this conclusion and other relevant planning information at its disposal, Entegrus concluded that the 2021-2025 Forecast Period required no material allocations towards devices or technologies to help manage the grid in lieu of the impact of new customer-owned technologies. Rather, amongst other findings more fully described in Section 1.5.1, Entegrus concluded that additional foundational System Renewal work was required for the 2021-2025 Forecast Period. This system remediation work will provide a stronger distribution system foundation for more integration of electric vehicle and distributed generation infrastructure investments in the next planning cycle (i.e. the Entegrus 2026-2030 DSP).

In the meantime, Entegrus will monitor residential transformer loading for concentrated patterns of electric vehicle adoption and will carry a stock of upsized residential transformers. Management recognizes the dispersion of electric vehicle adoption will not be homogenous across the service territory. For instance, the survey showed the most interest in EVs in St. Thomas and Chatham (see Attachment A, Part II, page 11). Accordingly, certain neighbourhoods may reach, or exceed, residential transformer loading capacities in the next 5 years despite the survey results. Beyond carrying a stock of upsized residential transformers, management will also look for system standards opportunities to make future electric vehicle infrastructure enhancement easier, such as using slightly larger transformer pads now to allow for potential future upsizing.

Similarly, the Innovative Research phone-based survey determined that customer demand for self-generation is relatively low (see Attachment A, Part II, page 2). The survey showed that only 2% of customers indicate they already self-generate electricity at home (see Attachment A, Part II, page 15). Further, 29% of residential customers believe their home could support self-generation (see Attachment A, Part II, page 14). These questions established context for the penultimate question, related to if customers' future interest in self-generation if their housing situation allowed for it (see Attachment A, Part II, page 16).

Figure 2-3: Customer Engagement Results – "If, in the future, your housing situation would allow you to do it, how interested would you be in generating energy yourself?"



As shown above, 31% of customers are interested in self-generation. However, it was also established that only 29% of customers believe their home could support self-generation and only 2% are actually self-generating now. This indicates that while there is some aspiration toward the technology, overall demand for self-generation is relatively low and it is also on a path to slow and manageable adoption in terms of the 2021-2025 Forecast Period. Of note, there is more interest in self-generation technology in the Entegrus-Main service territory than the Entegrus-St. Thomas service territory (see Attachment A, Part II, page 16).

In terms of both EVs and self-generation technologies, Entegrus recognizes that continued market analysis and planning is required and that these technologies will likely be a larger facet of the next planning cycle (i.e. the Entegrus 2026-2030 DSP). The continued development of these technologies and any government subsidies that later emerge for residential customers could drive more uptake in the future. As noted above, the additional System Renewal investment discussed throughout this DSP filing will provide a stronger distribution system foundation for more integration of EV's and distributed generation infrastructure investments beyond 2025 in the next planning cycle.

Phase 2 (June 2021 – July 2021)

As described in Section 2.2.2, Entegrus' ongoing interaction and consultation with its customers has reinforced objectives of reliability while also keeping distribution rates affordable. Entegrus gave strong credence to these customer preferences in designing the 2021-2025 Forecast Period. Accordingly, Phase 2 customer engagement was premised on the Entegrus plan to keep distribution rates unchanged throughout the 2021-2025 Forecast Period, aside from formulaic IRM adjustments.

Phase 2 of customer engagement involved a second, separate survey by public opinion research and consultation firm Innovative Research. This second survey was conducted closer to the end of the DSP filing preparation and was conducted by way of an online workbook survey, further supported by a phone-based reference survey. The focus of the Entegrus Phase 2 customer engagement efforts was primarily on three key areas: customer education (i.e. getting customers updated on Entegrus developments and the state of the system), preferences related to potential investments to be made in the 2021-2025 Forecast Period, and lastly, understanding customer priorities beyond 2025. This included other potential incremental investment alternatives that could potentially occur over the Forecast Period, which would not impact 2021-2025 distribution rates but which could impact rates in 2026 and beyond.

Section 4.1 provides additional details of the Phase 2 Customer Engagement work performed in support of this DSP, while Attachment B contains the full Customer Engagement Report. Section 4.1 also describes modifications that Entegrus made to this DSP filing in response to customer engagement.

2.1.3 Anticipated Sources of Cost Savings (5.2.1c)

Filing Requirement 5.2.1c: The sources of cost savings expected to be achieved over the forecast period through good planning and DSP execution

Over the 2021-2025 DSP Forecast Period, Entegrus anticipates that its customers can expect to benefit from cost savings and efficiencies stemming from the following three major sources:

- Managerial Innovation;
- Amalgamation-Related Capital Synergies;
- Benefits of Grid Modernization.

The following subsections describe each of the three categories of anticipated savings sources in greater detail, providing examples of practical and pragmatic approaches to capital work planning and execution that help generate benefits for Entegrus' customers and shareholders.

2.1.3.1 Managerial Innovation

The post-amalgamation rebasing deferral (in effect through to the end of 2025) benefits customers from each of the Entegrus rate zones (i.e. the Entegrus-Main rate zone and the Entegrus-St. Thomas rate zone). In postponing rebasing until 2026, distribution rates will be lower (starting in 2026) than they otherwise would have been without the merger.

As discussed in the 2017 MAAD application, among the sources of efficiencies are the following:

- *Regulatory Cost Reductions* due to the lower number of OEB filings, including adjudication of major rates applications, preparation costs of annual and quarterly reporting requirements, and synergies from combining participation efforts in OEB and IESO initiatives.
- *Labour Cost Reductions* achieved by staff attrition, which has been consistent with the strategy conveyed at the time of the MAAD application.
- *Board of Directors Cost Reductions* consistent with the lowering the combined number of Director positions relative to pre-amalgamation levels and the reduction in associated expenses.
- *Insurance, Pension and Other Administration Synergies* enabled by consolidation of employee bases and streamlining of the associated administrative expenditure drivers.

Beyond these core sources of savings, Entegrus expects to create opportunities for incremental value gains through managerial innovation in the Asset Management area. The following passages highlight the examples where Entegrus is making concerted efforts to execute on AM efficiency gains available today and chart the path for sustained efficiencies over the longer term through innovative pilots.

Exploring Inspection Cost Efficiencies through a Predictive Analytics Pilot: to help generate new asset health insights while managing OM&A spend, Entegrus looked to data science for help. Starting in 2015, staff selected a random sample of poles each year and conducted drill tests on these smaller subsets, with some additional testing results coming from pole attachment installation work. St. Thomas engaged a 3rd party to conduct a pole assessment survey in 2016. Entegrus has now harmonized its pole testing procedures across the entire service territory. With the help of METSCO Energy Solutions Inc. (METSCO), Entegrus used the randomly selected drill test sample results to run a predictive analytics pilot – to explore whether and how advanced statistical analysis could help it learn more about wood pole health across the system. Entegrus explored several potential approaches of translating the random sampling results into asset-specific predictive results for the remainder of the population, including a predictive "K Nearest Neighbours" Machine Learning algorithm. See METSCO's Asset Condition Assessment ("ACA") document contained in Attachment C for the discussion of the methodologies explored and interim insights generated.

Entegrus intends to continue exploring more means of enhancing its understanding of the state of its plant using data analytics, such as using the pole infrastructure management SPIDA models to explore correlations between drill test cavity and decay results with the poles' remaining strength values. The pilot work has provided important incremental insights to Entegrus' asset managers that will help calibrate future pilot work and enhance data collection and analysis practices going forward. More generally, this pilot is indicative of Entegrus' innovative and entrepreneurial approach to management of its system, which it expects to continue applying to future exploratory initiatives.

Evidence-Based Optimization of SCADA Infrastructure Deployment: as its system continues to evolve, Entegrus attempts to continually optimize the configuration of remote system operation and monitoring devices deployed across the circuits. Legacy Entegrus was an early adopter of SCADA, and one notable example of delivering incremental financial value in the course of this work involved refurbishment and redeployment of three early 2000's-vintage SCADA switches. These switches were moved from their original locations where system data suggested their presence was no longer critical, to the M21 feeder in Chatham that had become amongst the worst performing feeders. Entegrus refurbished the high voltage components of the legacy switches and upgraded the units' controls with modern equivalents and implemented the feeder sectionalisation. Thereafter, the refurbished switches were redeployed to the feeder points where system reliability data suggested they would provide more value. The success of this project became a driver for the Chatham and St. Thomas dynamic distribution grid (automated switching project) that was added to the Forecast Period in 2024 and 2025 based on customer engagement feedback (see Section 4.1.3.2).

2.1.3.2 Amalgamation-Related Capital Synergies

The amalgamation of Entegrus and STEI created multiple opportunities for cost synergies in operation and management of capital assets. Consistent with a typical post-M&A experience, Entegrus incurred initial transition costs to facilitate integrated operations in most of the cases described below. However, the utility expects these enabling investments to be offset by financial benefits over the longer-term, including efficiencies from higher utilization of existing assets, avoided costs of redundant equipment and technology, optimized travel costs, future procurement efficiencies, and others.

System Monitoring and Control: Entegrus began extending its system monitoring capabilities into the STEI service area at the behest of STEI management ahead of the formal commencement of merged operations. Prior to the amalgamation, the STEI distribution system had comparatively nascent system monitoring capabilities. These included a technologically outdated Supervisory Control and Data Acquisition ("SCADA") equipment interface developed in-house, which lacked many of the contemporary SCADA capabilities and was increasingly challenging to maintain. Similarly, STEI's Outage Management work relied on manual map-and-pencil tracking procedures that were more labour intensive and less responsive and precise than modern Outage Management System ("OMS") tools. The amalgamation enabled Entegrus to incorporate the STEI distribution system into its existing SCADA, and GIS platforms. Similarly, Entegrus integrated STEI's load flow and protection region information into its CYME power system modelling package used by system planners and designers. These integrations allowed Entegrus to extend its Control Room to cover the St. Thomas community as well, improving work safety, efficiency, and the mobility of crews between regions. Apart from modernizing the tools available to the former STEI staff and extending control room services, the transition also improved the operating cost economics of Entegrus' systems, as they now extend over a larger user base.

Asset Registry and Geospatial Mapping: independent of the amalgamation, and as discussed in more detail in Section 2.1.6, Entegrus made substantial enhancements to its GIS platform, which now formally serves as Entegrus' Asset Registry in addition to supporting investment planning and real-time work coordination efforts. A notable enhancement to the GIS system's overall efficiency involved integrating the back-end databases of the real-time "Operations" layer, and the "Engineering" layer used by designers and system planners. Entegrus estimates that the back-end integration reduces the data entry/extraction and verification effort by 35%, while ensuring greater information consistency between the two layers. As the timing of these GIS enhancements coincided with STEI integration work, Entegrus attained further efficiencies by integrating the STEI GIS data porting workflows with other ongoing activities.

Equipped with a centralized and streamlined GIS system that also contains more asset data than at the time of the 2016 DSP, Entegrus expects to benefit from higher throughput and accuracy of GIS-dependent tasks over the 2021-2025 timeframe, thus positively impacting both capital and OM&A work value chains.

Other Information Technology Systems: in addition to the above-noted systems that directly support the asset management and system planning work, Entegrus-STEI integration created positive information technology synergies throughout all major utility functions. This includes the following major areas and capabilities:

- Customer Information and Billing Systems;
- Wireless and Radio Communication Equipment and Networks;
- Meter Data Management Infrastructure and Databases:

- Financial Management and Reporting Systems;
- Warehouse, Fleet and Facilities Management Capabilities;
- Core IT Hardware, Software and Cyber-Security capabilities;
- Communications and Telephony Systems.

In all of the above functions, the STEI-Entegrus amalgamation produced both economic synergies and service value improvements by eliminating redundant equipment, licenses and related maintenance costs, centralizing and streamlining data entry, processing, retrieval and governance, and reducing the cost of incremental house keeping efforts rolled into the scope of integration work. Beyond these direct value gains, the centralized and enhanced IT capabilities will also enable improvements in throughput, quality and accuracy of work by Entegrus' employees using these tools. This is particularly notable for the former STEI service area, where the cost-minimizing information technology asset strategy led to a comparably lower utilization of formalized utility-grade IT systems.

Notwithstanding the significance of the above-noted enhancements, Entegrus notes that their overall magnitude is comparatively modest on the net basis. This is a function of the modest size of both predecessors, relatively lower utilization of advanced IT systems by STEI, and the offsetting costs of direct integration labour and change management activities (cross-training, enhanced support, etc.).

Operating Centre Efficiencies: In 2021 Q4, Entegrus will consolidate its Strathroy and St. Thomas operating centres. All activities previously performed out of the Strathroy facility will be transferred to St. Thomas, which is approximately 50 km away. This includes both planned and reactive construction, maintenance, and inspection work for the communities of Strathroy, Mount Brydges, Parkhill, Dutton and Newbury that were previously serviced by the Strathroy location. While the Strathroy office will be closed, Entegrus will continue to lease the garage and yard in Strathroy as a staging facility to house selected rolling stock, equipment and supplies. This will ensure that after hours response times can be maintained. Once the remaining Strathroy staff have been transferred to the St. Thomas facility, the rationalization of the existing building and supporting facilities will help reduce Entegrus' overall Facilities Management expenditures, and increase the utilization of the St. Thomas facilities that have sufficient existing room to incorporate the Strathroy labour force, after the completion of certain modifications described in Section 3.3.4.

Further, Entegrus has undertaken a project to improve its automation and telemetry capabilities in those communities most distant from its service centers. Newbury and Mt. Brydges were completed in 2020, with Parkhill and Erieau scheduled for completion in 2021. These improvements will provide additional real-time information to the Control room and operations crews to enhance our response, mitigation of temporary outages, and additional operations efficiency when performing work in the community.

The impact of consolidation on construction or reactive crews' drive time will vary depending on the community previously served out of Strathroy. In all cases, however, the change in distance (whether positive or negative) does not exceed the 50 km separating St. Thomas and Strathroy themselves. Importantly, the amalgamation-enabled increase in the total number of capital construction and system response resources in the northern part of Entegrus' territory therefore increasing the overall operating flexibility under both normal and emergency operating scenarios. Coupled with direct benefits arising from the reduced facilities footprint, the consolidation project entails a significant and sustainable value gain.

Materials and Supply Chain Efficiencies – since Entegrus and STEI have cooperated in a procurement cooperative for several years ahead of the amalgamation, the opportunities for any incremental volume-based purchase savings beyond those already in place are limited. However, the formal integration of the predecessors' procurement and warehousing operations is expected to have a positive influence on Entegrus' inventory costs due to higher consumption rates and an improved ability to optimize the volumes of spare parts and emergency inventory kept on hand. As a particular example, both Entegrus and St. Thomas maintained portable substations with distinctly differing capabilities. These two units can now be deployed across the entire service territory, supplementing each others' strengths and weaknesses, and providing an additional level of service to customers. Finally, a larger service territory also increases opportunities for re-deployment of equipment removed from service prior to the end of its economic life (e.g. transformers or meters due to capacity upsizing, changing configuration or refurbishment) to be successfully redeployed elsewhere in the system.

2.1.3.3 Benefits of Grid Modernization

The final major subset of savings and efficiencies that Entegrus expects to leverage over the Forecast Period stems from the continuation of its System Renewal and System Service work that seeks to modernize multiple aspects of its power system.

2.1.3.3.1 Legacy System Conversions

Consistent with the 2016 DSP, a major portion of Entegrus' System Renewal portfolio concentrates on conversion of aged and deteriorated low-voltage lines and intermediary step-down transformer stations to contemporary designs and higher voltage ratings. Ahead of the STEI amalgamation, Entegrus' system already featured extensive volumes of legacy overhead and underground feeders operating at 4.16kV and 8 kV voltages. The amalgamation has added to the scope of future voltage conversion needs by introducing a number of St. Thomas 2.4 kV delta-configured feeders into Entegrus' asset portfolio. By continuing its feeder conversion work, the utility expects to derive further efficiencies in the following areas:

- *Loss Reduction:* through use of higher-rated conductor and retiring stepdown transformers;
- *Plant Standardization:* to streamline future design work and rationalize spares variety;
- *Outage Risk Reduction:* through replacement of deteriorated materials and equipment;
- *Outage Duration Reduction:* through conversion of underground feeder segments; and,
- *Public Safety Enhancement:* through removal of assets built to outdated standards.

2.1.3.3.2 Distribution Automation Deployment

System Service investments in distribution system remote operation and/or automation carry through the Historical Period into the Forecast Period. Given the dispersed nature of Entegrus' service territory and significant travel distances between communities, outage response capabilities and policies are carefully considered from both customer satisfaction and cost management perspectives.

Notwithstanding the overall trend in outage durations, local areas where Entegrus deployed Distribution Automation ("DA") schemes during the Historical Period are benefitting from better reliability. For example, the utility estimates that the DA schemes installed on the circuits in Tilbury and Wallaceburg have combined to help avoid over 18,000 in Customer Hours Interrupted ("CHI") since being installed in 2017.

Automated switching and reclosing schemes also have potential to reduce Entegrus' emergency response expenditures – by eliminating the need for truck rolls where faults can be cleared automatically and/or reducing the urgency of reactive repairs where service can be restored by way of remote / automated switching to neighbouring circuits. Considering the recent increase in outages caused by Defective Equipment, Entegrus is aware that system automation alone does not obviate the need for renewal of increasingly deteriorating equipment as shown by the key assets assessed as in "Poor" or "Very Poor" condition by the ACA attached as Attachment C. However, given the positive recent results, the utility sees targeted DA as a viable tool that helps pace its asset renewal needs.

2.1.3.3.3 Smart Meter Fleet Modernization

Legacy Entegrus was among the early adopters of smart meter technology in the province and accordingly, a portion of its smart meter fleet dates to the mid 2000's and is nearing end of life. The St. Thomas smart meter fleet is, on average, approximately 3-5 years newer. While some of the original smart meter units failed and were replaced earlier, for other verified batches of meters, the re-sealing process allowed extension of life. In compliance with Measurement Canada requirements, pre-resealing verification occurs at the expiration of the original (post-manufacturing) seal period, and it is the general policy of Entegrus to re-seal and extend the lifecycle by an additional five years.

As additional Legacy Entegrus and St. Thomas meters reach end of life through the Forecast Period, management plans to do a staged replacement of the fleet to pace investments over the Forecast Period. This process is expected to first replace smart meters in those communities located furthest geographically from Entegrus operational centres. As this occurs, verified meter units would be removed from those communities and redeployed to other communities for which replacement has not yet occurred. This paced process may necessitate a second re-seal period for some meters. Along with the metering units themselves, Entegrus plans to renew its supporting AMI Infrastructure as well. Due to the merger, Entegrus is currently operating two distinct smart metering networks and intends to begin migrating to a single system across the service territory during the Forecast Period, while ensuring that existing investments in metering infrastructure are not stranded.

2.1.3.3.4 Elimination of Non-Standard Equipment

Along with legacy low-voltage feeders, Entegrus' system features other types of non-standard equipment that it now views as technologically outdated and continues to phase out from operation. These assets include:

- Porcelain Insulators that are being removed from service due to the severity of their in-service failure impact which creates a safety risk;

- Small-Diameter Copper Conductors (#4 and #6) – legacy conductor types known for their increasing brittleness and failure propensity with age;

- Poletrans Transformers – steel streetlight poles with built-in transformers inside the pole, which have long been discontinued from manufacturing, and are costly to maintain due to the need for an outage.

- Delta Customer services – services fed from a wye configured supply create a potential hazard as identified by the ESA and need to be updated to modern standards

- Submersible transformers – these below grade transformers are being replaced with above grade units due to increased failure rates and challenges when performing maintenance.

Although the number of the above equipment units in service today is relatively small, Entegrus expects their replacement to have a positive impact on reliability and safety, as their locations in the distribution system often represent particularly vulnerable points. Moreover, removal of these units from service will help further standardize Entegrus' equipment and reduce the variety (and inventory carrying cost) of spares kept on hand.

To further standardize its equipment base over time, Entegrus has also made a policy decision to no longer install any new steel or concrete distribution poles and replace the existing ones with wood poles. Unlike the porcelain insulators, small copper conductors, and poletrans transformers, Entegrus is not replacing the remaining steel and concrete poles until warranted by asset condition or coincident work synergies in the local area.

Overall, it is the belief of management that the scope, nature and variety of the cost-saving work discussed in this section shows meaningful progress since the 2016 DSP filing and conveys ongoing focus on innovation as a key component of the AM philosophy.

2.1.4 Period Covered by DSP (5.2.1d)

Filing Requirement 5.2.1d: The period covered by the DSP (historical and forecast years)

The forward-looking Forecast Period horizon covered by this DSP covers five calendar years from 2021 through 2025 inclusively. Since this second iteration of Entegrus' DSP is not supporting a rebasing application, Entegrus is not referring to the first year of the plan as the Test Year.

To report on historical accomplishments of Entegrus' two corporate predecessors, this Plan's Historical Period covers 2016-2020 inclusively. Given that the predecessors of Entegrus in its current form amalgamated in 2018, this DSP's Historical Period contains two distinct phases: one where the predecessors operated as two separate entities (2016-2017), and the other, post-amalgamation period (2018-2020). To distinguish between these two historical phases where, doing so is relevant, this document refers to them as the "Predecessor Historical Period" and the "Combined Historical Period" respectively. Consistent with this terminology, this DSP presents the operating and financial results of the Predecessor Historical Period separately for each pre-amalgamation entity.

2.1.5 Vintage of the Information (5.2.1e)

Filing Requirement 5.2.1e: The vintage of the information on investment drivers used to justify investments identified in the application (i.e. the information is considered current as of what date?)

This DSP is a product of integration of multiple information sources, each with its own information reporting cycle and logistical requirements for incorporation and reconciliation within the planning framework. Accordingly, the vintage of information comprising this document varies by the type of inputs as follows:

- Asset health and demographics data predominantly reflects the end of the 2019 inspection cycle as described in Section 3.2.3.1; and,
- Forecast Period financial forecast information reflects Entegrus Board approval in the fall of 2020 with adjustments in response to summer 2021 customer engagement feedback (as described in in Section 4.1), 2022-2025 System Access (as described in Section 0) and updates to System O&M (see Section 3.4), which are scheduled to be reviewed with the Board in the fall of 2021.

2.1.6 Important Changes to Asset Management Process (5.2.1f)

Filing Requirement 5.2.1f: Where applicable, a summary of any important changes to the distributor's asset management process (e.g. enhanced asset data quality or scope, improved analytic tools, process refinements, etc.) since the last DSP filing

Since the time of its 2016 DSP filing, Entegrus has taken important steps to develop, enhance or refine the tools, processes and policies that make up its Asset Management ("AM") Process. To capture its progress to date in a systematic manner, Entegrus broke down the entire AM process into four sequential stages displayed in Figure 2-4 and referred to in subsequent subsections. The stages track the process through which asset information gradually impacts intervention decisions. They are:

- *Capture Inputs*: collecting, organizing, tracking and storing objective information about the state and performance of its assets to make informed decisions. From a nearly infinite number of potential types of input data, utilities must select and track those that strike an optimal balance of incremental costs of data acquisition and benefits of incremental insights.
- *Transform Inputs into Outputs:* extracting value from asset information by subjecting it to the utility's "Tools" and "Rules" of analysis – technical analytics models and frameworks, and expressions of the utility's strategy, respectively. While the "Tools" work to derive technical insights from raw asset data, the "Rules" act as the assumptions for this analysis – helping asset managers (and their tools) create Outputs – inform trade-off decisions as to where to allocate the finite asset intervention resources in a manner that reflects corporate values.
- *Execute on Outputs*: having defined the Outputs of analysis – the size, mix and timing of capital and maintenance work programs – the Execution step seeks to implement them in a manner that makes the most efficient use of the utility's physical resources (labour, materials, tools etc.) while accounting for the near-term changes in investment needs. Efficiency and flexibility are the fundamental priorities of the tools and processes utilized in this step.

- *Learn and Adjust*: the final step of the framework entails a feedback loop, wherein the utility evaluates the actual outcomes of its asset intervention against the outcomes it targeted and the organizational costs of delivering these outcomes (including opportunities missed by making certain trade-off decisions). The purpose of this step is review and recalibration – of both the Tools of analysis and work delivery, and the Rules – expressions of corporate value trade-offs accepted by the utility, which define how the rules are applied.

2.1.6.1 Overall Approach since the last DSP

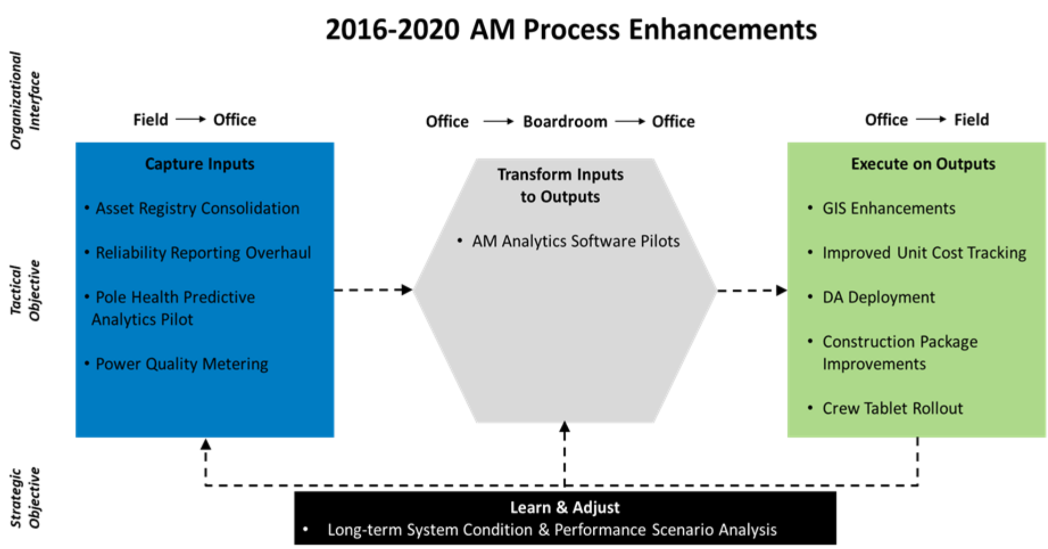
While Entegrus' core mandate has remained consistent throughout its existence, the utility began formally adopting the principles of Asset Management as a managerial and scientific discipline while preparing its inaugural 2016-2020 DSP. As discussed in its first DSP document, Entegrus retained METSCO to help establish the analytical and managerial foundations of an AM framework by way of conducting an Asset Condition Assessment ("ACA"), calibrating a set of basic asset failure risk analysis tools, and conducting workshops with Entegrus staff and Executive Team. As a part of this work, METSCO provided Entegrus with a set of recommendations for future AM improvements across the following areas:

- Standardizing and centralizing collection and tacking of asset condition data;
- Collecting additional types of asset condition data;
- Enhancing the collection and tracking of asset reliability data;
- Improving consistency and granularity of capital cost tracking; and
- Exploring opportunities for the introduction of formal AM analytics tools.

In targeting the improvements across these areas over the last DSP period, Entegrus remained pragmatic about the amount of financial resources at its disposal, and the aspects of its system performance that warranted the most attention in the near term. Given these realities, Entegrus sought to align its AM capability enhancement work with its most immediate operating needs, while maintaining the financial discipline inherent in Entegrus' strategy and its desire to maintain its current OEB efficiency ranking. This meant focussing on improvements in the areas that promised the greatest benefit across the system and seeking to gain experience with more advanced AM tools and frameworks in a way that limited financial impact.

Figure 2-4 captures Entegrus' most notable changes to its AM Process. As the figure indicates, and the following subsections discuss in greater detail, Entegrus' continuous improvement efforts impacted all major components of the AM value chain.

Figure 2-4: Major AM Process Changes 2016-2020



2.1.6.2 Enhancements: Input Capture

2.1.6.2.1 Asset Registry Consolidation

At the time of performing its first formal ACA study in 2015, Entegrus' data records exhibited numerous gaps in availability and quality of asset inspection and testing data records for the assets where this information was being recorded (i.e. station equipment). While some types of information were manually maintained and largely decentralized spreadsheets, others were kept in handwritten paper forms, or the inspection and testing reporting formats used by contractors. The resulting variety of formats, locations and tracking practices required a significant manual effort to assemble, digitize and reconcile the information for subsequent consideration in asset condition analysis.

Moreover, the decentralized record-keeping also resulted in multiple data gaps within and across asset classes, which Entegrus and METSCO could only rectify by extrapolating the empirically collected condition data where it was available across the rest of the asset class using asset age as a proxy. To address these specific issues and anchor its overall asset data governance framework, Entegrus decided to use its Geographic Information System ("GIS") as the formal Asset Registry that consolidates all asset health and demographic data. This ensures the data are maintained in a centrally defined and verified format stored in the GIS back-end and are easily retrievable in the course of executing any operational or planning activities.

Aside from establishing detailed data hierarchies and data validation rules within the GIS environment itself, a major portion of the improvement work concerned operational process change to ensure that all asset demographics, inspection and testing information captured in the field ended up being digitized and transferred to the GIS in a standardized and timely manner. Doing so required a significant collaborative effort across multiple departments to ensure procedural congruence between the new tasks, individuals, and resources at their disposal.

The establishment of a centralized Asset Registry and the supporting asset information governance framework enabled Entegrus to virtually eliminate the asset data gaps encountered in preparation of the latest ACA report. Moreover, the information contained in the GIS registry also assists Entegrus when planning and managing outages or other system emergencies, as the utility's operational staff can quickly identify the number and type of customers associated with a given asset or a protection area and verify whether the underlying asset indicates any concerns that can be mitigated ahead of time. Finally, the centralized Asset Registry and its increasing process integration with other systems such as the Outage Management System ("OMS"), CYME (Load Flow Analysis) and the Customer Information System ("CIS") has significantly simplified the task of data transfer for asset management information review.

2.1.6.2.2 Pole Health Predictive Analytics Pilot

As noted earlier in this section, Entegrus' historical approach to system inspections relied on exception-based reporting for overhead system inspection results, where crews relied largely on visual inspection methods and only captured condition data for assets that exhibited signs of unusual levels of decay. The advantage of this approach is that it manages the overall OM&A spend while meeting all prescribed inspection requirements and identifying the near-term asset intervention candidates.

While the above strategy remains in place to date, Entegrus recognizes the value of having additional information on the health of its overhead system for both near- and long-term System Renewal planning. Entegrus management were particularly interested in obtaining the data regarding the remaining strength and extent of internal decay of its wood pole population. Recognizing that the requisite drill testing costs on a large scale would not be compatible with its strategy, Entegrus devised a pilot approach that leveraged data science in hope of creating additional planning insights.

Starting in 2016, Entegrus began drill testing small, randomly selected samples of poles representative of different geographic parts of its system and different age tranches. The expectation underlying this approach was that the randomly assigned drill tests reflective of the population's demographic and locational diversity would enable Entegrus to draw statistically valid insights as to the internal integrity of the entire population. In 2019 Entegrus passed its pole drill sampling results to METSCO to consider during the asset condition assessment. METSCO explored several statistical approaches to derive the desired results, ranging from simple age-based linear extrapolation to more advanced Machine Learning techniques such as Statistical Bootstrapping with Replacement Technique and the K Nearest Neighbours ("KNN") Algorithm. Given the available data format, METSCO selected the KNN algorithm as the preferred means to attempt predicting the internal integrity for the wood poles that have not been drill tested.

The KNN is a supervised Machine Learning algorithm that predicts an untested pole's remaining strength by exploring the relationships between age, geographic location, and the remaining strength of drill-tested poles. Rather than relying on linear extrapolation, the algorithm works to identify the best data matches between the tested and untested poles, and then assigns the predicted test result on the basis of "dataspace proximity" between the poles with available and unavailable drill test data. To test the accuracy of the KNN approach, METSCO "held back" a portion of the poles sample where the drill test results were available and then used the algorithm trained on the remainder of the known sample to predict the drill test results where they were actually known. The algorithm's resulting accuracy in predicting whether a given pole would be deemed to have acceptable remaining strength, or would be flagged as approaching its End of Life was around 80% using pole height, type of wood, community of installation and geographic coordinates as predictive independent variables (with lower accuracy for predicting which specific poles were deteriorated). Entegrus and METSCO determined that this accuracy rate was not sufficiently high to consider including the predicted drill test results into the calculation of the utility' Health Index used in the Asset Condition Assessment (ACA) report.

Although the KNN algorithm pilot did not enable Entegrus to immediately expand the scope of condition parameters available for the ACA calculation, it has yielded important insights that will help the utility improve its data collection and tracking practices and inform the future predictive analytics experiments applicable to wood poles or other types of assets. In the interim, Entegrus considers its first attempt at asset health prediction as an important example of managerial innovation and responsible use of resources to achieve continuous improvement in the AM space.

2.1.6.2.3 Reliability Reporting Overhaul

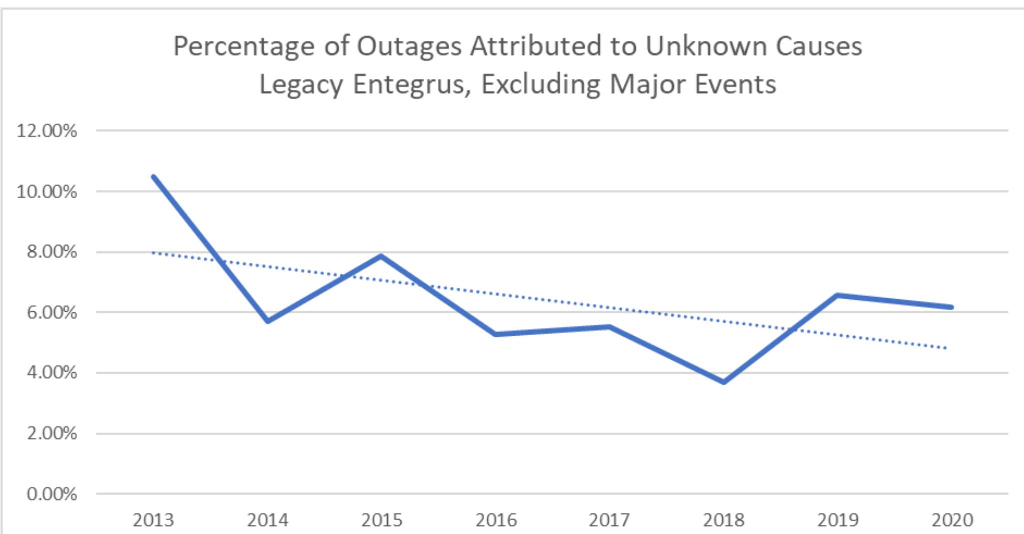
In its 2016 DSP, Entegrus recognized the limitations in its reliability tracking and reporting capabilities, including the fact that nearly a quarter of all 2010-2014 customer interruptions were attributed to the Unknown/Other cause code. While Entegrus suspected that a large portion of Unknown/Other outages was the result of tree contacts that could not be easily verified, it acknowledged that classifying a large portion of outages as Unknown/Other limited opportunities for future mitigation. More generally, Entegrus acknowledged the need to review its outage reporting investigation and tracking capabilities and make improvements to the underlying processes.

Over the course of the 2016 DSP period, Entegrus added additional skilled engineering (Asset Planning) resources, whose duties included working with Operations to devise a number of changes to Entegrus' legacy outage investigation and tracking practices, including:

- Devising more rigorous Trouble Sheet completion and submission processes;
- Initiating a monthly review process where Planning staff validated the Control Room reports; and
- Beginning to informally Capture Asset IDs of equipment suspected in causing malfunctions.

Entegrus believes that its increased rigour in outage investigation and analysis is partially the reason for the observed improvement in the average outage duration and frequency over the recent years, as discussed in more detail in Section 2.3.3.1.2. This is partially because the utility discovered that some of its 4.6 kV system outages may have been understated due to record keeping issues prior to the process reforms in 2017-2018. Notwithstanding this potential side effect of enhanced performance measurement focus, Entegrus expects that the underlying process improvements will have a positive impact on its reliability work over the longer term.

Figure 2-5: Percentage of Outages attributed to Unknown Causes by Year



However, as the downward trend line in the Figure above indicates, one of the ways in which reliability reporting enhancements are beginning to yield results is the reduction in the percentage of total outages where a cause could not be reliably identified and an Unknown/Other cause code has been applied. More importantly, better quality of data enables more comprehensive and detailed performance assessment and asset intervention planning work to take place going forward.

The amalgamation with STEI has also benefitted the development of Entegrus' overall reliability tracking capabilities, as STEI had experience with collecting more granular outage information, including a classification framework for interruption sub-cause codes. Owing to this framework, STEI's historical outage data showed what specific asset class was responsible for each Defective Equipment outage, enabling planners to analyze equipment performance trends with a greater degree of precision than in the Legacy Entegrus area. While Legacy Entegrus made some advancements in this area as well (e.g. tracking impacted Asset IDs), the integrated utility has, and will continue to seek to leverage STEI's Defective Equipment practices.

2.1.6.2.4 Power Quality Metering

In the 2016 DSP, Entegrus reported that transient power quality issues represented an area of concern for a subset of its Commercial and Industrial ("C&I") customers – particularly those operating increasingly sophisticated and sensitive equipment. At the time of the last DSP's preparation, Entegrus suspected that the source of power quality concerns could be the increased volume of intermittent renewable energy sources being connected to its system that was not originally designed to accommodate generation injection.

Consistent with its commitment from the 2016 DSP, Entegrus implemented a Power Quality Monitoring program to track and resolve any power quality issues performance over the last DSP period. As a part of the Power Quality program, the utility installed advanced power quality meters in select areas where customers voiced associated concerns. Aside from monitoring the meter results, Entegrus actively worked with the upstream supplier to ensure that any potential power quality issues arising upstream could be addressed.

Entegrus staff also worked directly with customers to investigate potential sources of power quality fluctuations within their own facilities and equipment. In the majority of cases, Entegrus' investigations concluded that the causes of concerns were unrelated to the performance of its own equipment or renewable generation facilities connected to it and also assisted customers in ultimately resolving these issues. Having invested in capabilities that enabled it to perform multiple in-depth Power Quality investigation projects over the 2016-2020 timeframe (see Section 2.3.3.1.3), Entegrus has recently seen less demand for such investigations than it did at the time of the 2016 DSP's preparation. Nevertheless, the utility has established a standing power quality survey for C&I customers that it continues administering to identify and rectify any emerging concerns.

2.1.6.3 Input-to-Output Transformation Stage Enhancements

2.1.6.3.1 AM Analytics

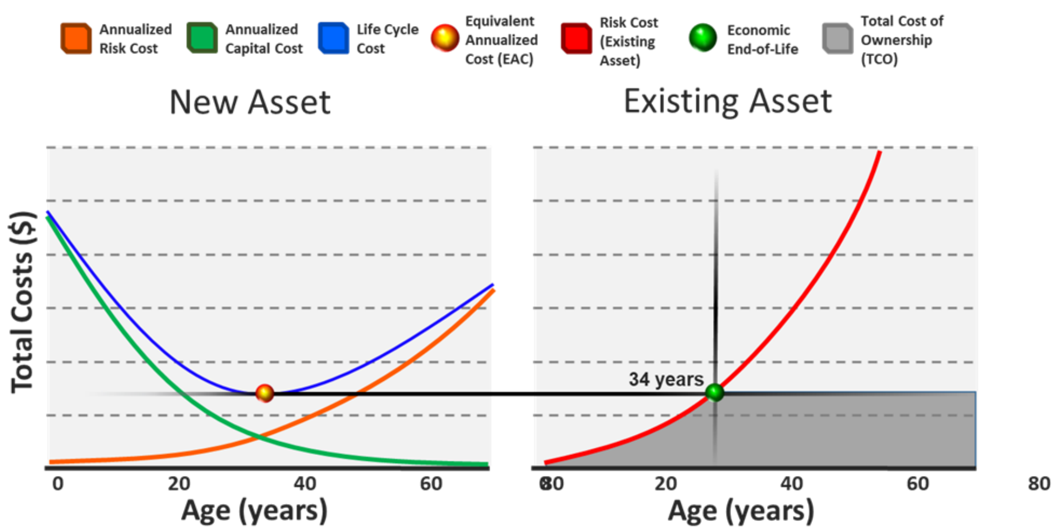
In its 2016 DSP, Entegrus noted that it would integrate a dedicated AM analytics software solution into its AM practices to improve the empirical rigour of planning and investment prioritization work and allow for scenario analyses to be conducted more quickly.

Entegrus now utilizes GIS-based AM tools to assist in performing asset analytics work. The Entegrus AM approach is based on the key principles underlying the ISO 5500x group of AM standards. Entegrus' first DSP was prepared using the PAS-55 standard (the precursor to ISO5500X) as a reference. As such, an exploration of the system grounded in ISO5500X standard is a logical continuation and enhancement of Entegrus' AM work.

To perform analysis supporting AM planning, Entegrus asset planners and METSCO rely on algorithms configured to prioritize and optimize future utility investments by minimizing equipment's lifecycle cost.

This considers the relative magnitudes and timing of asset intervention costs (over each asset's lifecycle, relative to the risk costs inherent in various modes of that asset's failure over time. There are three primary types of risk costs associated with asset failure – reliability costs, safety costs and environmental costs. The probability and impact of incurring these costs are established by way of industry engineering research (to configure the probability functions of equipment failure over time) and actuarial research (to estimate the economic impact of outages to different types of customers and/or of environmental and safety incidents on individuals and society).

Figure 2-6: Asset Lifecycle Cost Minimization Approach



As Figure 2-6 indicates, the objective is for asset replacements to occur at the lowest point in an asset lifecycle cost curve – which corresponds to the point in time when an existing asset's annualized capital costs (which decline over time) equal its annualized risk costs (which increase over time as the probability of asset failure increases). The final output is a recommended multi-year investment program that identifies specific volumes and timing of investments by asset class and location to minimize the system's aggregate lifecycle costs within the constraints of a specific scenario – such as labour, equipment and financial resources available per year. See Section 3.3 for additional information on the methodology underlying the Entegrus AM analytics.

2.1.6.4 Output Execution Stage Enhancements

2.1.6.4.1 GIS System Enhancements

In addition to the improvements of the information stored in Entegrus' GIS system discussed above, the 2016-2020 DSP period saw the utility make significant improvements to the system's functionalities and the efficiency of supporting it. Prior to 2017, Entegrus shared its GIS functionality with the Municipality of Chatham-Kent. While the shared GIS arrangement created some financial synergies, the two entities' respective use cases for the system began to diverge. Entegrus sought to increase its ability to use the system in-real time to coordinate engineering and construction work, outage restoration and system inspection activities. To this end, Entegrus added additional in-house GIS resources starting in 2016 and established a standalone GIS platform in 2017 to simplify its further development and integration with other utility IT systems like OMS, CYME, AutoCAD design package, and others.

Since establishing a standalone GIS platform, Entegrus worked to enhance the efficiency of its use and consistency of the data contained across its layers. As referenced in Section 2.1.3.2, the GIS system relies on two layers – an "Operations" layer used by the line crews to coordinate real-time work and the "Engineering" layer used by designers and system planners to maintain the currency of asset data and configuration and explore the feasibility and impact of future modifications. A significant limitation associated with the status quo arrangement of the two layers was that they relied on separate back-end databases. This implied that any system design modifications or data updates would have to be re-drawn or updated separately to capture them in each layer's back-end database. Entegrus addressed this inefficiency by migrating both layers to a common back-end database that streamlines data management effort by an estimated 35%, while ensuring that GIS data used by the planning, design and operations staff is accurate and consistent.

By increasing the operating efficiency and information consistency of its GIS system, Entegrus took meaningful steps towards improving the overall efficiency of its capital construction process. The specific improvements contribute to increased engineering design and records management throughput and the decreased likelihood of costly field work delays, or errors caused by inaccurate system or asset-specific information. As such, the GIS system enhancements created opportunities for cost efficiencies at the two opposite ends of a typical capital project value chain – namely the initial engineering / design work and the field construction activities.

2.1.6.4.2 Improved Unit Cost Tracking

Over the 2016-2020 DSP period, Entegrus developed and refined a comprehensive framework for unit-cost based estimation across its most common capital construction and maintenance cost activities. In its present form, the framework contains over 100 individual asset assemblies, corresponding to specific types and configurations of equipment or maintenance activities. Each asset assembly consists of discrete labour, materials or equipment cost components that make up the full value chain of utility construction or maintenance, including:

- Material procurement and delivery costs;
- Engineering and design labour costs;
- Site preparation labour and equipment costs (e.g. pole removal, trenching, directional drilling);
- Line crew construction or maintenance labour;
- Cost of supporting vehicle utilization by size.

Entegrus' planners developed this framework together with subject matter experts from the Engineering, Operations, Finance, Supply Chain, and Fleet Management functions. Planners updates the unit costs framework in consultation with relevant SMEs each year to reflect the latest available costing information and update the framework as necessary.

2.1.6.4.3 Distribution Automation (DA) and Smart Grid Technology Deployment

As shown in Table 2-4, Entegrus deployed 13 Distribution Automation ("DA") units over the 2016-2020 period to manage the impact of outages faced by its customers through automatic restoration and / or minimization of affected areas. A major driver of these projects has been reducing all-cause outage hours experienced by Entegrus customers. As a heavily embedded utility, loss of supply creates significant challenges for customers, and one for which traditional improvement programs (i.e. tree trimming, asset renewal) are beyond Entegrus' control. These automation projects have been designed to mitigate loss of supply events as well as provide direct benefits to Entegrus' system and have resulted in a combined 18,000 of avoided Customer Hours of Interruption ("CHI") between 2017 and 2020. All units deployed entail a mix of reclosers and automated load break switches.

Table 2-4: Distribution Automation Installations over the Historical Period

Community	Devices Count and Manufacturer	Installation Timing
Tilbury	3 Switches (S&C Electric)	January 2016
Wallaceburg	4 Switches (S&C Electric)	November 2016
Blenheim	3 Switches (S&C Electric)	November 2019
Ridgetown	3 Switches (G&W Electric)	November 2020

In addition to these automated devices, the Entegrus system contains a number of other remotely controllable Smart Grid switches, including the recently refurbished and redeployed units installed on the worst performing M21 feeder discussed in Section 2.1.3.1. Apart from helping manage reliability performance, these technology investments help Entegrus to reduce the labour and vehicle costs associated with outage response work, thereby making more resources available for other types of system improvement activities.

Smart Grid solutions are becoming an increasingly viable option in Entegrus planners' system performance management toolbox. In select cases targeted DA installations can provide cost-effective means of managing the reliability impact of an aging asset base, as discussed in Section 0.

2.1.6.4.4 Construction Package Improvements

Entegrus' amalgamation with STEI enabled several best practices sharing opportunities within the system planning and asset management functions of the former utilities. While the legacy STEI staff and customers have benefited from a more advanced state of Entegrus' operational technology tools and formalization of AM work, the Legacy Entegrus staff have benefitted from exposure to the rigour and quality of STEI's construction planning work. This is particularly exemplified by the quality and detail of information comprising the Construction Packages issued to the former STEI crews.

As with more granular tracking of outage sub-cause code metrics, the quality of the former STEI's construction planning process is related to the former STEI's efforts to adopt the key principles of the ISO 9001 reporting quality management standards. Over the course of the Forecast Period, Entegrus expects to explore other aspects of the former STEI's construction planning best practices and incorporate its core elements into the integrated utility's operations where suitable. The anticipated impact of the associated process review and improvement activities involves better coordination between all elements of construction value chain and higher accuracy of work execution.

2.1.6.4.5 Crew Tablet Rollout

Over the course of the Historical Period, Entegrus has gradually rolled out mobile tablet / laptop capabilities for the members of its labour force who spend a significant portion of their time in the field. Currently equipped with time tracking, remote GIS system access and various reporting software capabilities, the mobile solutions enable the field staff to reference the latest system information, streamline the amount of time spent in the office, and gradually digitize the field operations records system. While many field work reporting processes continue to rely on paper-based form, the rollout of mobile crew capabilities creates a platform for gradual digitization of the operational records processes over the Forecast Period.

2.1.6.5 Learning and Adjusting Stage Enhancements

As part of its 2021-2025 DSP preparation process, Entegrus planners facilitated a risk-based capital investment planning exercise that reviewed a range of potential investment allocation scenarios over and beyond the planning horizon. The exercise concentrated on the System Renewal and a portion of the System Service portfolio related to Smart Grid / automation investments. The goal of the exercise was to evaluate operational implications of the current expenditure focus / trajectory and any potential modifications. The underlying analysis assumed a level of System Access and General Plant investments commensurate with the past trends and making special allowances for known or anticipated major projects over the Forecast Period.

Although this DSP filing is not tied to rate impacts for the 2021-2025 Forecast Period, as part of this strategic planning exercise, Entegrus considered multiple investment scenarios involving various trade-offs (and increases) in volumes, mix and pacing trade-offs. These were analyzed and proposed to customers for the Plan (as discussed in more detail in Section 4.1). Specifically, four broad investment scenarios were analyzed with assistance from METSCO. Customer engagement ultimately supported a hybrid scenario which balanced sustainability and reliability level (setting a target for SAIDI of 1.42 and for SAIFI of 1.01 using the 5-year loss of supply and major event day adjusted results) against the need to keep distribution rates affordable. This scenario addresses the replacement of aged and degraded infrastructure, while also including a paced voltage conversion process and a paced removal of submersible transformers from the system.

In general, Entegrus management considered four scenarios in the course of establishing the base plan:

- **Scenario I – "Stay the Course":** Maintain the historical levels of effort and philosophical approach for System Service, System Renewal, and General Plant categories. Specifically, maintain current asset investment trajectories for low-voltage conversion, critical asset replacement, station maintenance, smart metering investment and system modernization.

- **Scenario II – "Focus on Condition":** Incremental increase in System Renewal investment while maintaining other investment categories. The Incremental spending is focused on critical asset replacement and continuation of low voltage conversion programs. The incremental investment would be used to improve all "Very Poor" Health Index units from a system over a decade, with the anticipation that reliability would gradually improve by having fewer unplanned asset failures, as there would be fewer assets in the "Very Poor" classification.

- **Scenario III – "Balance Condition & Performance**": Incremental increase in investment equivalent to "Focus on Condition." The incremental investment would be split between addressing assets in the "Very Poor" Health Index classification and smart-grid investments targeting SAIDI. This would attempt to provide additional focus on maintaining or improving the customer experience through sectionalisation projects and automatic restoration installations on larger feeders where an alternate supply was available. The incremental investment would be used to reduce the number of "Very Poor" Health Index units in the system over a decade. Reliability would gradually improve by having fewer unplanned asset failures and greatly improved system sectionalisation and automation.

- **Scenario IV – "Focus on Performance & Maximize Conversion**": Incremental increase in System Renewal investment beyond the level in "Focus on Condition" while maintaining other investment categories. The Incremental spending is focused on continuation of our low voltage conversion programs and station decommissioning. The incremental investment would be used to drive additional low voltage conversion, which would in turn improve many "Very Poor" Health Index units over a decade. Reliability would gradually improve by having fewer unplanned asset failures as there would be fewer assets in the "Very Poor" classification.

Management centred its base plan on Scenario II above, with a primary focus on System Renewal Investment, while maintaining other investment categories and adding some elements from Scenario III and IV. The plan predicates this on a paced smart meter replacement and re-sealing strategy, which will require close monitoring against the risk of technological obsolescence and in-service failures due to the age of the Entegrus smart meter fleet. Ultimately, the customer engagement process retained Scenario II, focused on reduction of assets with "Very Poor" Health index, while also adding two projects with elements of Scenarios III and IV. Accordingly, incremental spending is focused on System Renewal critical asset replacement with some additional System Service automated switch restoration (smart grid) investments and a continuation of low voltage conversion programs at a faster than originally planned pace for 2021-2025. The customer engagement process is more fully described in Section 4.1. Allowances were also made for some major anticipated one-time projects, such as the capacity addition from the Edgeware TS breaker positions described in Section 4.2.

In the end, the planning analysis exercise resulted in Entegrus increasing its System Renewal expenditures relative to historical levels, including specific annual allowances for proactive underground renewal work. Aside from helping determine the optimal level and mix of System Renewal investments for the 2021-2025 timeframe, the strategic planning exercise described above provided critical insights for management's future deliberations on capital investment strategy into the future.

2.1.6.6 Looking Ahead to 2021-2025

Over the 2021-2025 Forecast Period horizon, Entegrus expects to focus the bulk of its continuous improvement initiatives in the AM space on those initiatives which align with the "Executing on Outputs" and "Learning and Adjusting" stages of the conceptual AM process diagram shown in Figure 2-4. Having established a firmer grasp on detailed capital unit cost planning and enabled the digital reporting capabilities from the field, the utility expects to focus its efforts on data tracking and reporting to create a continuous feedback loop between detailed planning assumptions and work execution outcomes.

As its risk-based AM planning capabilities further evolve, Entegrus also expects to explore changes to its operational data capturing practices that may further refine its AM analytics work – such as capturing more equipment-specific outage cause information to help calibrate Entegrus-specific failure probability distributions. As noted earlier, Entegrus expects to continue refining its utilization of predictive analytics in procuring asset condition data for wood poles and potentially other asset types. Similarly, Entegrus may explore opportunities to collect additional types of condition data where it is relying on age data alone, such as potential testing of underground cables.

2.1.7 DSP Contingencies (5.2.1g)

Filing Requirement 5.2.1g: Aspects of the DSP that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (OEB decision on Long Term Load Transfers) and the expected dates by which such outcomes are expected or will be known

Successful execution of the projects comprising the 2021-2025 work program is contingent on multiple internal and external factors discussed below:

2.1.7.1 Implications of the COVID-19 Pandemic

Entegrus' ability to plan for and execute its Forecast Period capital program may be affected by the health and safety restrictions and economic implications of the COVID-19 pandemic. These may include volatility in connection demand levels from new and existing customers, societal restrictions (i.e. lockdowns) that could materially alter the means and/or feasibility of field work execution, and others. Entegrus will approach these potential issues as the situation unfolds and will make necessary adjustments in compliance with the government and OEB instructions and by consulting other industry participants affected by similar uncertainty. The extent of the impacts is not expected to be known until some time after the pandemic is complete, as regulations and best practices are updated, and impacted customer sectors begin to recover.

2.1.7.2 Weather / Climate-Related Challenges

Certain System Service and System Renewal investments comprising the planned capital work program require planning and coordination of outages on the relevant portions of the Entegrus system and/or the upstream supplier's transmission and distribution assets. Entegrus' ability to plan for and execute the requisite outages may be affected by the local, sub-regional or regional system constraints that may emerge due to extreme weather such as abnormally high shoulder season temperatures.

Beyond outage scheduling, weather volatility may also affect the nature and locations of System Renewal work over the Forecast Period. Should storm activity affect certain portions of Entegrus' fragmented and expansive distribution system to a significant degree, the utility may be required to reallocate the funds targeted for planned voltage conversion activities to address the immediate restoration needs elsewhere in its system. Entegrus will manage the work execution issues through close coordination and communication with its generation and load customers, the contractor community, the upstream supplier and members of its mutual assistance groups discussed in Section 2.2.2.4. This is expected to be an ongoing reality given recent weather volatility trends.

2.1.7.3 Customer or Third-Party Requests

Entegrus' ability to deliver the planned work program within the contemplated scope and timelines may be affected by requests from current or prospective customers and other third parties that may ask the utility to execute certain projects (e.g. existing infrastructure relocations, new connections or enhancements). A recent example of material changes to the distributor's planning assumptions driven by customer requests is the new Transformer Station that was planned to proceed on the basis of anticipated need to connect a new agricultural cultivation facility but was ultimately put on hold as the customer withdrew its application. Should similar requests emerge over the Forecast Period, Entegrus will work with the requesting parties and other affected stakeholders to reasonably accommodate all requests as per the Distribution System Code ("DSC"). The utilization of contractors to perform certain underground or overhead capital construction work in such a situation may also afford mitigation from capital plan deviation.

Conversely, due to the pandemic, many employers in the province have moved towards more employee work from home arrangements. Anecdotally, management is aware of a trend whereby former residents of the GTA are migrating into the Entegrus service territory (particularly to Chatham, but in other Entegrus communities as well). This seems to be further spurring an upswing in new housing starts. It is currently difficult to forecast how long this trend will last and Entegrus continues to actively engage the region's commercial developers and the broader business community and seek to ensure that the Plan remains sufficiently flexible. While it is expected that the volatility around residential migration will settle in the post pandemic period, the unpredictability in timing and volume of customer driven work will be an ongoing reality.

2.1.7.4 Regional Electricity Infrastructure Requirements

With its system spanning four different Regional Planning Zones, Entegrus is an active participant in Ontario's regional infrastructure planning activities coordinated by the IESO and Hydro One. Given the variety of stakeholders whose needs and planning assumptions inform the content of the four overlapping regional planning processes, Entegrus' investment work program mix may be affected by the changes driven by the recommendations of one or more regional infrastructure planning undertakings. Should such conditions present themselves, Entegrus will work to re-prioritize its planned work program to the degree permissible by operational and financial constraints and considering all rate funding options at its disposal. This is expected to be an ongoing reality.

2.1.7.5 Unexpected Insights from Amalgamation-Related Activities

The 2021-2025 investment program comprising this DSP reflects Entegrus' current understanding of the technical, environmental and safety issues inherent in the recently integrated former STEI system. Should further analytical or operational activities identify any incremental risks that warrant mitigation through near-term capital investments, Entegrus may amend the currently forecasted mix of investments to accommodate the emerging needs according with its investment prioritization practices at the time. This is expected to be a decreasing risk as additional planning cycles are completed; data sets are harmonized and a deeper knowledge of the entire Entegrus system is achieved.

2.1.7.6 Property Rights and Access-related Considerations

Certain construction and maintenance activities over the Forecast Period may require Entegrus to obtain access or easement rights with respect to public or privately owed lands. Should Entegrus be unable to secure these access rights within the timelines contemplated in the project plans, it may adjust the project timelines or explore alternative locations or asset configurations as appropriate. This is expected to be an ongoing reality.

2.1.7.7 Other Contingencies

Other contingencies that may affect Entegrus' execution of the current DSP include but are not limited to the following events that may affect its capital work planning or execution abilities or priorities:

- government and OEB policy amendments;
- changes to technical industry standards or planning assumptions;
- higher-than anticipated uptake in emerging technologies like electric vehicles and storage;
- potential M&A activities involving Entegrus as either an acquiring or a target utility; and
- other factors.

Entegrus accepts these eventualities and will actively manage them through regular engagements with policymakers, industry organizations, employees, customers and contractors. In terms of electric vehicles, Entegrus will monitor residential transformer loading for concentrated patterns of electric vehicle adoption and will carry a stock of upsized residential transformers. Despite the customer engagement determination that uptake of EVs is not anticipated to be significant amongst Entegrus customers during the 2021-2025 Forecast Period (see Section 0), management recognizes the dispersion of electric vehicle adoption will not be homogenous across all communities and certain neighbourhoods may reach, or exceed, residential transformer loading capacities in the next 5 years. Accordingly, management will maintain stock of upsized transformers and will also look for system standards opportunities to make future EV infrastructure enhancement easier, such as using slightly larger transformer pads to allow for potential future upsizing.

2.1.8 Grid Modernization, Energy Resources & Climate Change Adaptation (5.2.1h)

Filing Requirement 5.2.1h: Identification of projects related to cost-effective grid modernization, distributed energy resources, and climate change adaptation and how these projects address the goals of the Long-Term Energy Plan

Entegrus' capital and operating work programs include the following activities that promote grid modernization, use of distributed energy resources and climate change adaptation:

Installation of Distribution Automation and other Smart Grid Equipment: proactive feeder sectionalization and deployment of automated or remotely operable switches, reclosers and sensory equipment to address high priority areas with significant reliability and/or access issues. This work is expected to continue improving the efficiency of outage restoration work on the parts of the system enabled with this equipment and as discussed below, sectionalization becomes more important as voltage conversions result in longer 27.6kV feeders with higher customer counts.

Voltage Conversion: upgrading of outdated low-voltage feeders in the 2-8 kV range to the standard 27.6 kV design to accomplish the following objectives:

- reduce losses;
- streamline design work;
- manage the volume of reactive response work by replacing the most vulnerable assets;
- reduce the variety of inventory kept on hand;
- increase feeder connection capacity / transfer capability; and
- accommodate future penetration of electric vehicles and distributed generation sources.

Replacement of technologically outdated assets: grid modernization efforts to remove assets that no longer meet Entegrus' design standards such as Poletrans transformers, porcelain insulators and low-diameter copper conductors. Replacing these assets with modern equivalents will support reliability performance, resiliency and operational efficiency, while reducing Entegrus' outage response, design and supply chain costs through standardization of equipment.

FIT Program Accommodation: the DSP contains a dedicated annual allocation to support the operations of renewable generators operating in Entegrus' service area.

Industry Participation: Entegrus continuously evaluates opportunities for integration of new technologies into its grid operations through review of industry publications and active participation in Ontario industry forums such as the Electricity Distributors Association ("EDA") and the Utilities Standards Forum ("USF"). Moreover, in contemplating its grid modernization strategy, Entegrus may reference relevant government policy documents such as the Long-Term Energy Plan to ensure broad consistency of objectives and consider all factors that may influence the future of distribution grids.

Power Quality Issues Surveys: Entegrus proactively engages its C&I customers to jointly explore any potential issues associated with power quality they are experiencing in order to plan for and undertake any system modifications that may be required to address them.

New Technology Adoption Surveys: Finally, when contemplating investments in new technology, Entegrus seeks to rely on objective insights from its customers, whose behaviour may shape its grid innovation portfolio. To this end, Entegrus took an opportunity to gauge customer plans and attitudes regarding adoption of electric vehicles (“EV”) and distributed generation (“DG”) technologies while conducting a biennial Public Awareness of Electrical Safety Survey (“PAESS”).

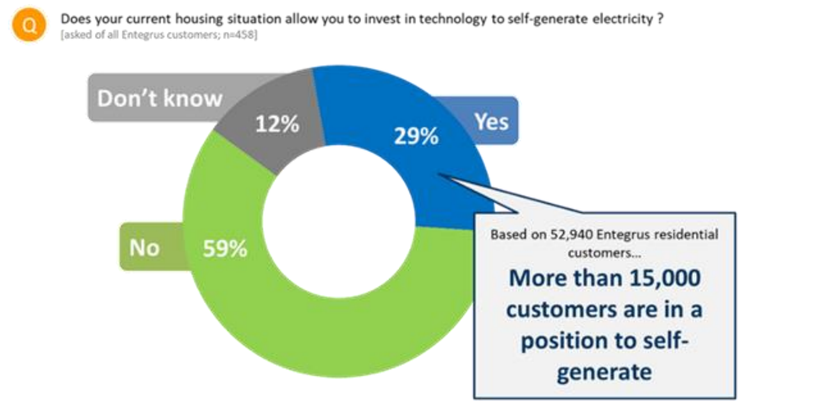
As noted above, given the industry speculation that rapid pace of EV and DG adoption may warrant investments in advanced real-time grid monitoring and balancing technologies, Entegrus sought to understand whether and to what extent these technologies would become prevalent in its communities.

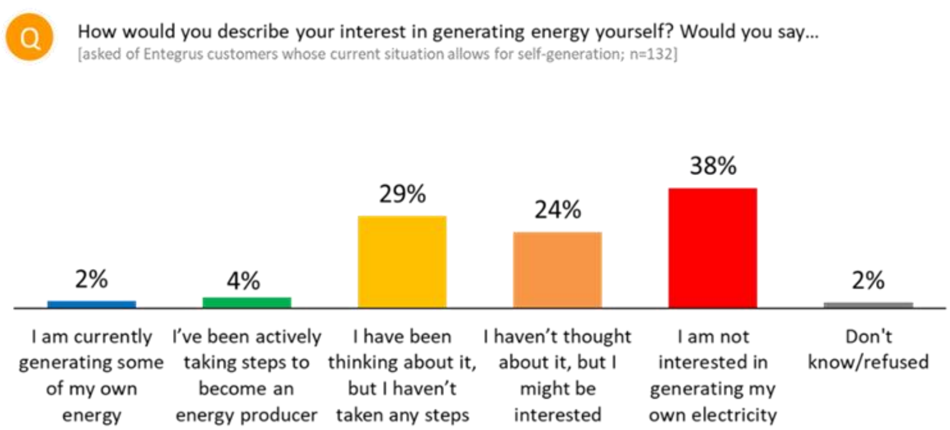
The survey results are detailed in Section 0. As noted, the results suggest that adoption of EVs is likely to occur very slowly in the Entegrus service area, both as a result of a relatively low projected demand for new automobiles in general, and limited interest in EVs in particular. The survey also established that the current EV penetration rate has been minimal, with an estimated 99% of vehicle owners and leasers driving traditional combustion engine automobiles.

While the survey results provide no indication of a rapid uptake over the Forecast Period, Entegrus plans to monitor the future EV adoption rates and engage its customers on the technical and economic considerations of doing so. Future government policy directives and/or consumer initiatives could change customer sentiment quickly. This approach reflects another survey insight (see Attachment A) – namely that four out 10 (41%) of customers would be at least somewhat likely to turn to Entegrus for advice. While uptake of EVs is not anticipated to be significant in the Forecast Period, Entegrus will monitor residential transformer loading for concentrated patterns of electric vehicle adoption and will carry a stock of upsized residential transformers. Management recognizes the dispersion of electric vehicle adoption will not be homogenous across the service territory and certain neighbourhoods may reach, or exceed, residential transformer loading capacities in the next 5 years. Management will also look for system standards opportunities to make future electric vehicle infrastructure enhancement easier, such as using slightly larger transformer pads now to allow for potential future upsizing.

Again, as detailed in Section 0., the likelihood of Entegrus customers investing in DG technologies appears to be relatively low. Despite the reduction in the cost of solar photovoltaic (“PV”) generation technology over the past decade, the moderate interest levels suggested by the survey are a function of only 29% of residential customer believing that their home could support self-generation, and only a third (33%) of this group thinking or actively taking steps to produce their own electricity. This may be a function of past regional DG “red zone” restrictions on certain portions of the Entegrus service territory, typically based on transmission station capacity, or other demographic factors.

Figure 2-7: Survey Results on DG Adoption by Entegrus Customers





Survey results suggest that Entegrus' customers see it as an important source of information on self-generation technologies, with 67% of respondents at least somewhat likely to turn to Entegrus for information and advice when it comes to residential self-generation options and solutions.

On balance of insights available from the above survey, and in light of its other investment priorities, Entegrus planners do not currently see a rationale for any immediate investments triggered specifically by the need to offset the anticipated impact of EVs or DG in its service area. At the same time, the responses suggesting that customers see Entegrus as a notable source of knowledge on new technologies suggest a future opportunity to develop technology-related information campaigns that would also help Entegrus maintain awareness of trends in customer adoption rates or attitudes. While concluding that no immediate investments are required, Entegrus planners are evaluating a range of potential changes to their construction standards – to better prepare the system for potential higher future uptake by making modest proactive changes to standard features of newly installed equipment.

Each of the named projects above relates to the following objectives in the Long-Term Energy Plan as follows:

- Installation of Distribution Automation and Smart Grid Equipment, Voltage Conversions and Replacement of technologically outdated assets support:

  - Energy storage
  - Delivering a flexible and efficient system
  - A coordinated, cost-effective, long-term approach to replacing assets at end of life
  - Customer reliability
- Fit Program Automation supports
  - Energy storage
  - Delivering a flexible and efficient system
  - Customer reliability
- Industry Participation support:
  - Energy Storage
  - Bulk system planning process
  - Regional Planning Process
- Power Quality Issues Surveys support:
  - Energy Storage
  - Customer reliability
- New Technology Adoption Surveys support:
  - Bulk system planning process
  - Regional planning process
  - Delivering a flexible and efficient system
  - A coordinated, cost-effective, long-term approach to replacing assets at end of life
  - Customer reliability

2.2 Coordinated Planning with Third Parties (5.2.2)

Filing Requirement 5.2.2: A distributor must demonstrate that it has met the OEB's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors, the Independent Electricity System Operator (IESO) or other third parties where appropriate. A distributor must provide the following for any regional planning process, any REG related investments or any other planning initiatives that require coordination

2.2.1 Summary of Consultations (5.2.2a)

Filing Requirement 5.2.2a: A description of any consultation(s), including: The purpose of the consultation, whether the distributor initiated the consultation or was invited to participate in it, the other participants in the consultation process (e.g. customers, transmitter, IESO), the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan), an indication of whether the consultation(s) affected the distributor's DSP as filed and if so, a brief explanation as to how.

In preparing this DSP, Entegrus relied on the insights from a range of consultative activities that occur in the normal course of its operations, as well as those engagement activities dedicated specifically to DSP development. These include a variety of consultative activities with Entegrus customers, regional planning work across the four electricity regions that make up Entegrus' service area, issue-specific collaboration with Hydro One, and engagements with local municipal authorities and the developer community. The following sections describe each type of activities in greater detail.

2.2.2 Customer Consultations

2.2.2.1 Overview

As noted in Section 1.4.4, Customer and Community Focus is a key strategic pillar at Entegrus, which the utility ensures to incorporate in all facets of its operations. Entegrus recognizes that technological progress is giving its customers an increasingly greater range of options to manage their consumption needs, while the economy is stretching their budgets further with every year. In light of these circumstances, Entegrus sees it as its fundamental responsibility to convey the value proposition of its operational and investment work to its customer base with maximum clarity, explaining the trade-offs that its staff face in allocating the rate revenues, and taking steps to incorporate customer preferences in the investment decisions to the extent allowable by engineering and economic considerations.

An illustrative example of Entegrus' responsiveness to customer feedback gathered through consultation is the community of Wallaceburg, where the customers (particularly industrial) expressed a clear need for tangible reliability improvements during the previous round of customer engagement. In response to these comments, Entegrus successfully worked with the upstream supplier to install several new automated switches in the Wallaceburg area in 2016 to help restore power outages before the response crews arrive on scene, where doing so is technically feasible. As a result of these targeted System Service investments, Entegrus estimates that the local customers avoided over 17,000 Customer Hours of Interruption to date.

More generally, the customer engagement work ahead of the last (2016-2020) DSP preparation confirmed that reliable supply of electricity and the pace of electricity bill increases are the most significant concerns for Entegrus' customers overall. As discussed throughout this document, the bulk of Entegrus' operational and investment activities coincided with these priorities, both in the nature of capital work planned and the focus of operating activities such as customer outreach on power quality, collaboration with Hydro One to manage the impact of Loss of Supply events and continuous improvement activities in the AM area.

Prior to amalgamation with STEI in 2018, Entegrus embarked on customer and community outreach activities focussed on ensuring that the customers of both utilities understood the nature of the amalgamation, experienced minimal inconvenience during the transition, and were given an opportunity to voice their concerns, preferences and expectations. To accomplish this important objective, Entegrus relied on a multi-channel strategy that included dedicated website pages, billing inserts, and "open house" sessions hosted by senior leaders and directors in the communities of St. Thomas, Strathroy and Chatham.

The following sections provide additional information on Entegrus' customer consultation activities, including those conducted specifically to inform this DSP document.

2.2.2.2 Regular Engagement and Consultation Activities

2.2.2.2.1 Residential Customers

Entegrus provides 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 Entegrus relies on the following channels:

- **Call Centre Communication**: inquiries, complaints and commentary conveyed to Entegrus' customer service representatives, equipped with a range of IT tools and information resources to accommodate requests or direct the inquiries elsewhere in the organization;

- **Engineering Department Communication**: all classes of Entegrus customers can contact the utility's Engineering Department to request a range of services or provide feedback on utility activities such as cable locates, move in / move-out support, metering accuracy verifications, modifications to utility pole attachments, small vegetation management projects, or resolution of other technical questions or concerns;

- **Neighbourhood Communication**: Prior to working on customer premises or nearby, Entegrus staff drop off information letters to the customers. 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 Entegrus contact. Entegrus staff frequently engage in dialogue with customers throughout the implementation process. In addition, prior to conducting work that will result in commercial outages, Entegrus staff visit customer premises to survey the best times for outages.

- **Website and Social Media Feeds**: Entegrus customers can gain a variety of information online regarding the utility's operational and planning activities on the company's website (redesigned in late 2020) as well as via social media feeds. This includes information about upcoming vegetation management processes, as well as an enhanced online outage map launched in later 2020 and which extended this technology to St. Thomas. Entegrus employs web traffic analytics to identify the issues of the greatest interest to the customer base to inform its future planning and communications efforts.

- **Survey Tools:** Entegrus' residential customers are able to share their feedback on a range of topics by way of a variety of surveys the utility conducts. These include surveys administered during the DSP Customer Engagement work, as well as bi-weekly transactional surveys that follow resolution of a customer-initiated request, annual "top-down" Customer Satisfaction

Surveys, Public Safety Awareness Surveys, and others administered over the phone, by mail or online.

- **Community Events:** Entegrus participates in a variety of public events throughout the communities in its service territory. These engagements create opportunities to increase public awareness on topics such as conservation, electrical safety, or new services available to customers. Moreover, public events are a unique source of informal and unsolicited feedback on the utility's performance, as they enable face-to-face interaction with individual consumers that may not otherwise contact the utility.
- **Advertising:** Entegrus 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 Entegrus 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.

2.2.2.2.2 Industrial and Commercial Customers

In addition to the engagement tools available to residential customers listed above, Entegrus consults with its Industrial and Commercial customers through issue-specific in-person discussions led by members of the Engineering, Metering, Customer Service or other teams that C&I customers can request by contacting the utility. Entegrus also carries out periodic information sessions for the members of the C&I rate classes on specific topics involving changes to government policy, the utility's own service offerings or strategic initiatives such as the Entegrus-STEI amalgamation. 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 filings, both through meetings and surveys.

The technical expertise and highly customized needs of many larger customers are a key source of information that helps calibrate Entegrus' plans on modifications to system capacity, local grid protection arrangements, or power quality requirements. Beyond their technical acumen, C&I customers are a key source of feedback on the scope, nature and practical implementation of Entegrus' Conditions of Service and planning insights regarding the trends affecting specific sectors of local economy.

2.2.2.2.3 Generators

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

2.2.2.3 Consultations with Municipal Authorities

Entegrus maintains a regular line of contact with municipal authorities throughout its service territory. Information sharing and planning / coordination meetings occur across the organizational levels and technical domains, including engineering, operations, finance, customer care, community outreach, and corporate strategy. Municipal governments are the primary means of connecting Entegrus to the local real estate development community. As such, they provide a key input on the volume and timing of potential new connections and plant relocation work, which collectively make up the bulk of the System Access spend. Moreover, given that Entegrus serves mature communities with diverse and extensive non-electrical infrastructure renewal needs, municipal consultations are a key conduit for coordinated planning of public works projects to help streamline costs and reduce inconvenience caused by construction activities.

2.2.2.4 Electricity Industry Consultations and Collaboration

Over the years, Entegrus staff have actively participated in numerous planning and policy consultations conducted by the Ministry of Energy, Northern Development and Mines and the Ontario Energy Board ("OEB"), including initiatives to establish and coordinate the delivery of electricity cost relief programs, the development of the Distributor Scorecard policy framework, various technical Distribution System Code amendments, and many others. Beyond the initiatives carried out by the government and its agencies, Entegrus collaborates with its industry peers through technical forums that pool expertise and resources in devising responses to common industry challenges.

This collaborative work includes cooperation to identify supply chain opportunities, refine load forecasting techniques and standardize equipment design and safety standards through the Utilities Standards Forum ("USF"), discussions of safety-related topics through the Infrastructure Health and Safety Association ("IHSA"), ongoing discourse on policy matters as a part of the Electricity Distributors Association ("EDA") and best practices sharing and a pooled equipment buying group through Grid Smart City ("GSC"). The outcomes of this work are directly reflected in Entegrus' planned capital work program in the form of materials procurement efficiencies, modern construction standards and other managerial insights.

In the latter half of 2020 and through 2021, the above-noted best practices sharing and pooled equipment buying assisted with pandemic-driven supply chain issue mitigation. Pandemic-driven shortages led to longer lead times and price inflation on key inputs. Management responded by establishing additional supplier relationships, increasing lead times on supply orders and working with customers and developers to increase awareness of the industry supply situation.

Entegrus is also a proud member of various mutual assistance groups, including three Ontario-based groups and two groups whose membership consists predominantly of American utilities:

- The CEA Ontario Mutual Assistance Group (ONMAG)
- The Western District LDC Mutual Assistance Group
- The South-Central Ontario LDC Mutual Assistance Group
- The Great Lake Regional Mutual Assistance Group (GLRMAG)
- The North Atlantic Regional mutual Assistance Group (NAMAG)

Membership in mutual aid arrangements makes Entegrus eligible to provide and receive mutual assistance in the event of emergencies. Participation in mutual restoration efforts provides valuable training and skill development and exposes its staff to alternative work execution and management approaches.

Overall, Entegrus sees industry collaboration as an important source of technical and economic insights, and an opportunity to stress-test the validity of its own assumptions regarding customer needs, technical and regulatory requirements, or the optimal ways of meeting them. As such, industry collaboration also acts as an ongoing informal source of peer feedback and comparison that helps Entegrus managers strive for continuous improvement.

2.2.2.5 Overall Impact of Customer Consultations (5.2.2b)

Filing Requirement 5.2.2b: Where a final deliverable is available, provide details of the final deliverable; or where a final deliverable is expected but not available at the time of filing, provide information indicating:

- The role of the distributor in any consultation
- The status of the consultation process
- Where applicable the expected date(s) on which final deliverables are expected to be issued

2.2.3 Regional Planning Process

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

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

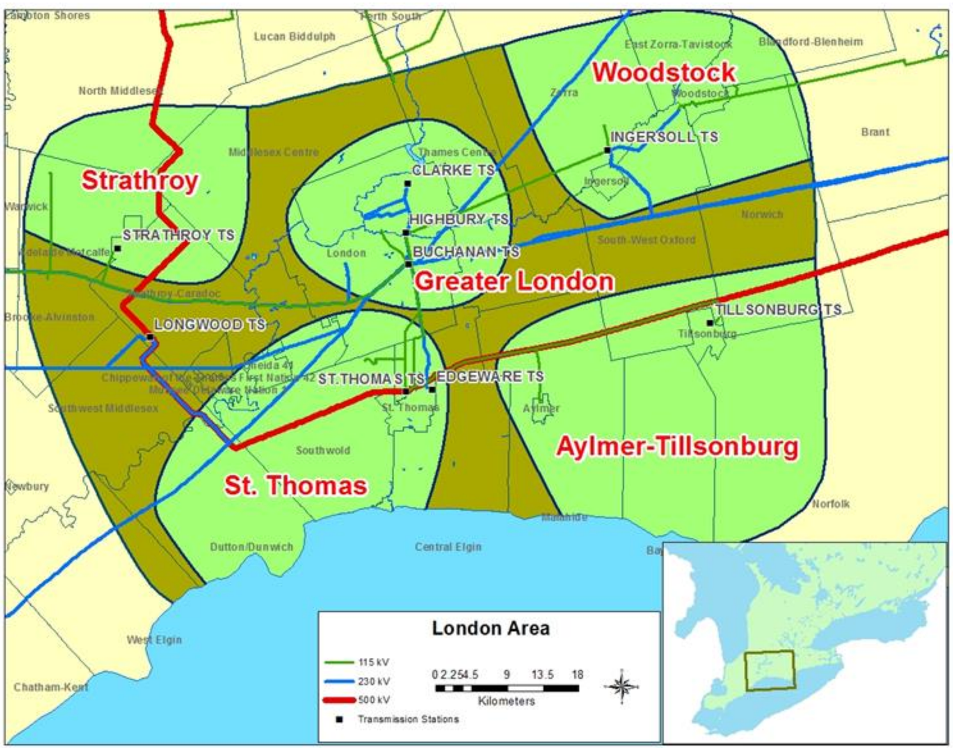
While logistically challenging, Entegrus' participation in four separate planning regions enables it to maintain a direct line of contact on the longer-term planning matters with the Independent Electricity System Operator ("IESO"), Hydro One's Transmission and Distribution subsidiaries, and all other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

2.2.3.1 London Area Region

As shown in the map below, the London Area Region and the five sub-regions that comprise it:

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

Figure 2-8: London Area Region and Sub-Region



Entegrus has assets in two London Area sub-regions, namely the Strathroy and St. Thomas planning zones. Entegrus was invited to participate in the latest round of the regional planning for the London Region, for which the beginning coincided with the submission of Entegrus' 2016 DSP. At that point, Hydro One completed the Needs Screening for the area in April of 2015, concluding that certain needs in the region could benefit from regional coordination, which in turn led to a Scoping Assessment completed by the IESO in August of the same year. While the report recommended that an Integrated Regional Resource Plan (IRRP) be developed for the Greater London sub-region, it found no need for further regional planning activities in the St. Thomas sub-region and recommended to address the Strathroy sub-region needs by way of local wires-only planning between Entegrus and Hydro One.

Hydro One and Entegrus jointly issued a Local Planning Report on Strathroy TS Transformation Capacity in September of 2016 to address the potential need for additional transformation capacity at Strathroy TS.

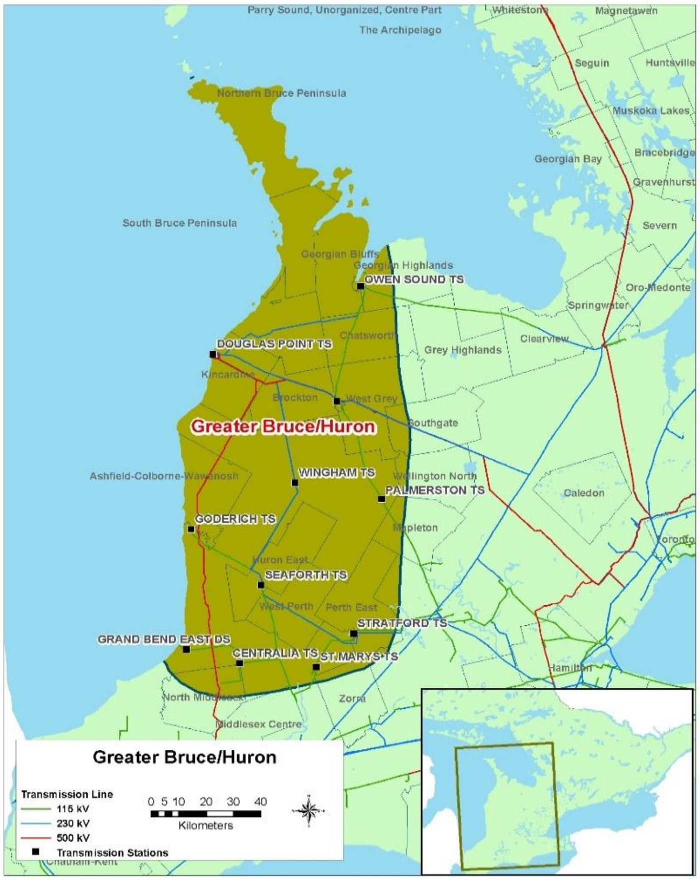
At the time of the report being produced, Hydro One was in the early stages of replacing transformer T1 at the station on a like-for-like basis, the work on which was completed in 2017. The station's second transformer T2 was replaced in 2012. The aim of the study was to address in detail the station's load forecast, since the 2015 Needs Assessment projected that Strathroy TS would exceed its 10-Day Summer Limited Time Rating ("LTR") over the next decade. Having reviewed the latest load information in 2016, Hydro One and Entegrus found that the original 2015 forecast assumptions overestimated the station's load by 23% and agreed to revise the net 10-year forecast by 17%. As a result of this revision, the study participants concluded that no further actions were required.

The IESO's London Area Scoping Assessment and Hydro One-Entegrus Local Planning Report are attached in Attachment D and Attachment E respectively. While the regional planning activities in the London Region continued with the preparation of the Greater London IRRP and a Regional Infrastructure Plan ("RIP") in 2017, Entegrus is not appending them as they have no relevance to its infrastructure. The next round of planning for the region is expected to commence in the next three to five years.

2.2.3.2 Greater Bruce-Huron Region

The map below showcases the planning boundaries for the Greater Bruce-Huron planning area, which includes Hydro One's Centralia TS that feeds the Entegrus community of Parkhill. This area is currently undergoing its second cycle of regional planning activities that commenced in 2019. Entegrus was invited to participate in these regional planning activities by the IESO.

Figure 2-9: Greater Bruce-Huron Planning Region



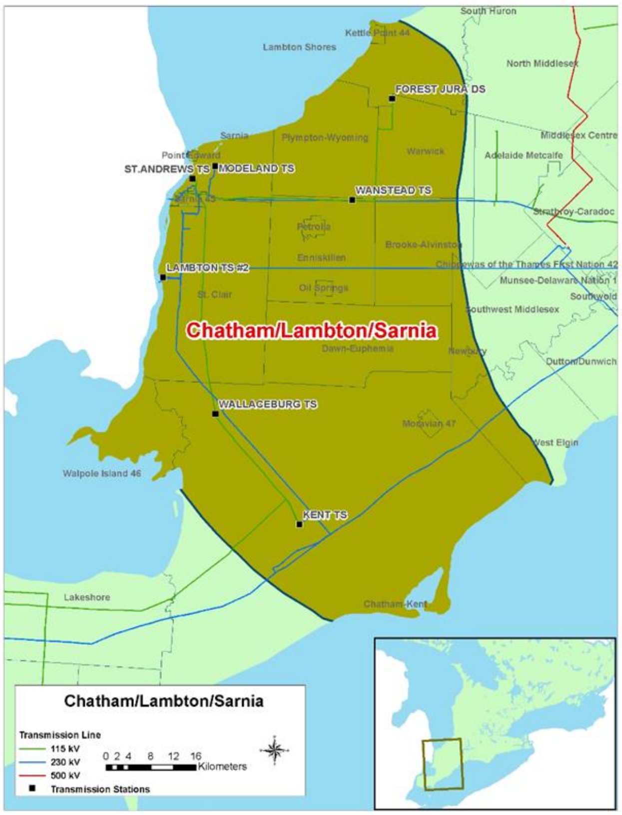
As a part of the latest round of regional planning, Hydro One completed a Needs Assessment in May 2019, which was followed up by the IESO's Scoping Assessment completed in September of the same year. Both studies identified Hydro One's 115 kV circuit L7S as a particular area of focus, given the capacity constraints on the line itself and the delivery point performance of the substations that the line feeds. Based on these conclusions, the IESO Scoping Assessment has determined that an IRRP be undertaken for the sub-region supplied by the L7S circuit, while a number of end-of life station transformer replacement projects in the area proceed further by way of local wires-only planning between Hydro One and the relevant utilities. Since none of these stations feed Entegrus communities under normal circumstances, the utility is not actively participating in these discussions.

The IRRP process is currently underway and was not completed in time to be included in this DSP. The IESO Scoping Assessment is attached in the Attachment F.

2.2.3.3 Chatham-Kent/Lambton/Sarnia Region

Figure 2-10 below shows the Chatham-Kent / Lambton / Sarnia planning region, which encapsulates the majority of Entegrus' physical service territory. The latest round of the planning activities in the region concluded in 2017 with the release of Hydro One's Regional Infrastructure Plan ("RIP"). Entegrus was invited to participate in these regional planning activities by the IESO.

Figure 2-10: Chatham / Sarnia / Lambton Region



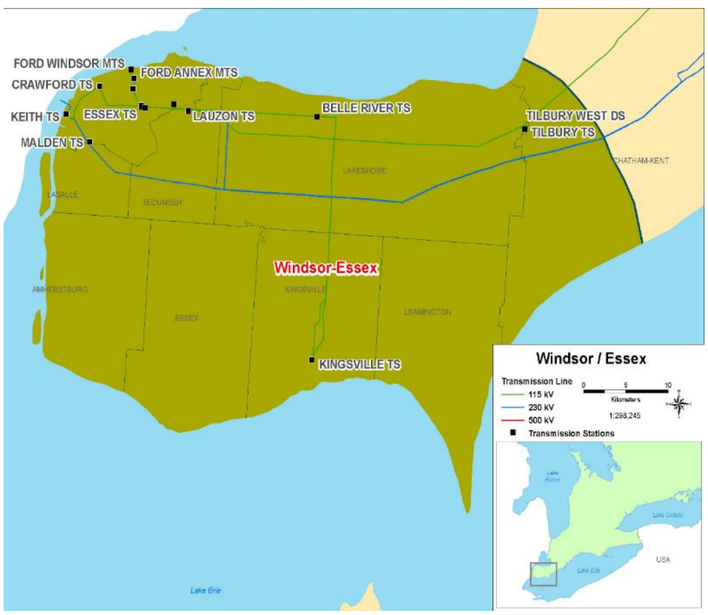
Along with Entegrus, the entities that take part in the planning work for this area are the IESO, Hydro One and Bluewater Power. Having completed the Needs Assessment, Hydro One identified that no IESO Scoping Assessment to consider any potential upside for integrated resource planning work was required. As such, all subsequent planning work identified in the Needs Assessment was to be completed by Hydro One and the relevant local distributors. This included several System Renewal projects involving replacement of Hydro One's station transformers, and a local study to investigate potential capacity overload of transformer T3 at Kent TS that supplies Entegrus. Using the latest available load forecast data, the Needs Assessment identified that Kent TS unit T3 would exceed its 10-Day LTIR over the next decade in the event of an outage to its companion unit T4.

Following the direction from the Needs Assessment, Hydro One and Entegrus jointly developed a Local Plan, which determined that no immediate capacity expansion investments were required at Kent TS, since the downstream distribution system could accommodate sufficient load transfers to offload the potential overloading at Kent TS. An August 2017 RIP is attached in Attachment G re-iterated this finding and outlined the scope for several local station renewal projects that do not impact Entegrus. As such, there are no final deliverables from the consultation project to be included in the DSP. The next round of regional planning for the Chatham-Kent / Lambton / Sarnia is underway. Entegrus understands that a new transmission reinforcement line from Longwood TS to the Sarnia area is under consideration, among other initiatives.

2.2.3.4 Windsor-Essex Region

The regional planning activities for the Windsor-Essex Region were completed in the fall of 2019. Entegrus was invited to participate in these regional planning activities by the IESO. Aside from Entegrus, Hydro One and the IESO, other utilities in the regional planning activities are ENWIN Utilities, E.L.K. Energy, and Essex Powerlines Corporation. Figure 2-11 displays the region's boundaries but does not show the Kent TS which was included into the scope of the most recent cycle as discussed below.

Figure 2-11: Windsor-Essex Region



The Windsor-Essex area has recently seen rapid and very significant growth, largely due to continued commercial greenhouse activity expansion in the Kingsville and Leamington areas, further invigorated by the legalization of cannabis. Following significant recent transmission system enhancements such as the Supply to Essex Country Transmission Reinforcement ("SECTR") project, the September 2019 IRRP identified several incremental wires and non-wires projects that may be required in the area.

The most significant element of the Windsor-Essex planning process for Entegrus was the inclusion into its scope of the anticipated capacity needs at the Kent TS, which technically lies outside of this planning area's boundaries. The concerns regarding Kent TS capacity arose as a result of the plans for a new agricultural cultivation operation requiring upwards of 55 MW of system capacity being planned in the Chatham area. Since the regional planning activities for the Chatham-Kent / Lambton / Sarnia area (where the Kent TS normally belongs) concluded in 2017, the participants included the Kent TS needs into the Windsor-Essex evaluation work. However, once the potential agricultural cultivation customer in question withdrew its connection application, Entegrus and the IESO updated the area's load forecast by reducing the anticipated load requirements accordingly.

The IRRP was completed in 2019 and identified the need for a new Dual Element Spot Network ("DESN") station in the Chatham area, to accommodate the load requirements that were set to exceed the available capacity at Kent TS by 2023. In the immediate term, Hydro One and Entegrus worked to plan for amendments the local area protection schemes required to accommodate the project's first phase expected as early as 2020. However, due to the downturn that the cannabis industry in the second half of 2019, the applicant withdrew its connection request. Given this development, the need for the new station or any other system configuration changes disappeared, leading the planners to suspend any further work. Attachment H contains the IESO's IRRP for the Windsor-Essex region.

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

As the preceding sections indicate, Entegrus has been actively involved in the regional planning work across many parts of Southwestern Ontario. In the process, it built up and refined increasingly detailed load forecasts, while supporting its partner utilities with expert knowledge of the local distribution systems. The outcomes of this work are technical planning decisions reflected in the 2016 Strathroy TS Local Planning Report and the 2017 Kent TS T3 Local Plan, where in-depth joint Hydro One - Entegrus analysis mandated through the Regional Planning Proceedings, ultimately revealed opportunities to forgo costly reinforcements in the near term. While it is impractical to speculate as to whether these projects would be proceeding forward without the rigour inherent in the Regional Planning framework, Entegrus' experience over the Historical Period points at a number of value gains for the utility and its customers from participating in Regional Planning work.

Based on the insights obtained form the Regional Planning work, this DSP does not include any investments identified during formal regional planning activities. However, the Plan does include a System Service project associated with local capacity constraints – namely the addition of a new breaker position and associated protection and feeder infrastructure at Hydro One's Edgeware TS to maintain operating flexibility in the St. Thomas area. While the impact of COVID-19 makes near-term load forecasting work more challenging, Entegrus will continue participating in all relevant facets of the Regional Planning activities to remain flexible in the face of future economic fluctuations.

2.2.4 IESO Comment Letter (5.2.2d)

Filing Requirement 5.2.2d: For REG investments a distributor is expected to provide the comment letter provided by the IESO in relation to REG investments included in the distributor's DSP, along with any written response to the letter from the distributor, if applicable. The OEB expects that the IESO comment letter will include: Whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO, the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments, whether the REG investments proposed in the DSP are consistent with any Regional Infrastructure Plan

Entegrus submitted a request for letter of comment to the IESO in July of 2020. The IESO reviewed the letter containing Entegrus' 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 I) the IESO notes that Entegrus has consulted the with the IESO. In its correspondence, the IESO confirms that Entegrus 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 Entegrus REG Plan does not include any investments specific to connecting REG for the Forecast Period 2021-2025. With no required REG investments, the system operator concluded that no comment letter was required to address the substance prescribed in the OEB's Chapter 5 Filing Requirements, Section 5.2.2.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

Filing Requirement 5.2.3: Distributors are expected to use qualitative assessments and/or quantitative metrics to monitor the quality of their capital expenditure plans, the efficiency with which plans are implemented, and/or the extent to which planning objectives are met. This information should be used to continuously improve a distributor's asset management and capital expenditure planning processes.

2.3.1 Overview

This section describes the utility's approach to measuring performance in the areas supporting the development and delivery of the capital work program. The discussion addresses historical performance of Entegrus' two predecessors and that of the integrated utility since the amalgamation. It also sets out the measures that Entegrus plans to track and report on over the 2021-2025 Forecast Period.

The last DSP submissions for both the Legacy Entegrus and the former STEI included tracking of metrics that also appeared in the distributor scorecards, as well as additional custom metrics. Entegrus is proposing some updates to the previous approach, including an additional subset of custom DSP metrics to track for the 2021-2025 timeframe. These metrics are summarized in Table 2-5 and then more are more fully described below.

2.3.2 Scorecard

Please see Attachment J and Attachment K for copies of the most recent Entegrus scorecard and the former STEI's 2017 scorecard. Note, that the Entegrus scorecard includes the 2018 and 2019 results of the integrated utility's operations, and that the historical comparators post-merger is shown from the Legacy Entegrus (Entegrus- Main) perspective.

2.3.3 Measures for Distribution System Planning Process Performance (5.2.3a/b/c/d)

Filing Requirement 5.2.3a: Identification and definition of the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and driver (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to: Customer oriented performance (e.g. customer bill impacts, reliability, power quality), Cost efficiency and effectiveness with respect to planning quality and DSP implementation (e.g. physical and financial progress vs. plan, actual vs. planned cost of work completed), Asset and/or system operations performance (e.g. line losses)

Filing Requirement 5.2.3b: Unit cost metrics for capital expenditures and operating & maintenance (O&M) per customer, kilometer of line, and peak capacity as outlined in Appendix 5-A.

Filing Requirement 5.2.3c: summary of performance for the historical period using the methods and measures (metrics/targets) identified and described above, and how this performance has trended over the period.

Filing Requirement 5.2.3d: An explanation of how historical performance has affected the DSP (e.g. objectives, investment priorities, and expected outcomes) and how it has been used to continuously improve the asset management and capital expenditure planning process.

This section discusses the measures which Entegrus tracked over the previous DSP period, as well as those it proposes to track over the 2021-2025 Forecast Period. As noted, many of the 2021-2025 measures represent a continuation of those used in the last DSP. There are also new indicators that management plans to monitor and vet via internal consumption over the Forecast Period.

Given its Historical Period experience discussed in this Section 1.3, Entegrus may augment or discontinue its use of any the below metrics at any point during the 2021-2025 Forecast Period, should it determine that the cost of measurement does not match the value of any incremental insights.

The following table provides a summary of the metrics tracked in this DSP Plan. It should be noted that Entegrus tracks additional (all) scorecard measures, but the table below includes only those measures directly relevant to this DSP filing.

Table 2-5: 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

2.3.3.1 Customer Oriented Measures

2.3.3.1.1 Customer Bill Impacts

Description: Two measures can be used to quantify the impact of Entegrus' rate application on customers' electricity bills:

- Percentage Average Total Bill Impact; and
- Average Dollar Impact.

Entegrus' historical and future target is to keep the bill impact lower than 10% for all customer classes. This aligns with the customer preference to keep distribution rates affordable (see Section 4.1.2) and mitigates rate shock.

In this context, as discussed in Section 0, it should be noted that there are no bill impacts from 2021-2025 arising from this Application. T

Customer bill components controllable by Entegrus include distribution rates (comprised of monthly service charges and volumetric rates), commodity loss factors and regulatory asset recovery rate riders to dispose of the balances in the Deferral and Variance Accounts requested.

The Figure below captures these controllable 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.

Table 2-6: Entegrus Residential Customer Bill Impacts

Description	2016	2017	2018	2019	2020
Entegrus - Main Rate Zone					
Percentage Average Total	-1.23%	-2.08%	2.68%	0.19%	1.14%
Average Dollar Impact	-$1.80	-$2.68	$2.73	$0.19	$1.60
Entegrus - St. Thomas Rate Zone					
Percentage Average Total	-0.73%	2.24%	-1.16%	0.36%	-1.01%
Average Dollar Impact	-$0.97	$2.85	-$1.24	$0.38	$1.42

Impact on DSP: The relatively low recent bill impacts are consistent with the Entegrus re-basing deferral until 2026, as well as the fact that ICMs have not been filed. This is consistent with Entegrus' intention to keep distribution rates affordable for customers. As noted in Section 0, there are no proposed incremental rate impacts arising from this DSP filing for the period from 2021-2025.

2.3.3.1.2 Reliability

Description: Entegrus 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 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 customer interruptions by the total average number of customers served.

The table below presents the overall reliability results for Entegrus and its predecessor entities across the metrics noted above. Please note, the results presented in the table below are on a combined basis for all years shown.

Table 2-7: Overall Reliability Performance Statistics: Entegrus and Predecessors

Description	2016	2017	2018	2019	2020
All Cause Codes					
SAIDI	1.02	2.77	4.23	3.37	2.22
SAIFI	1.00	2.02	2.35	1.99	1.74
CAIDI	1.02	1.38	1.80	1.69	1.27
MAIFI	3.06	4.36	5.87	4.34	4.21
Excluding Loss of Supply					
SAIDI	0.67	1.35	2.59	1.73	1.47
SAIFI	0.73	0.92	1.48	1.02	1.18
CAIDI	0.91	1.46	1.74	1.69	1.25
MAIFI	2.89	3.07	3.99	2.42	2.97
Excluding Loss of Supply and Major Event Days					
SAIDI	0.67	1.35	1.89	1.73	1.47
SAIFI	0.73	0.92	1.21	1.02	1.18
CAIDI	0.91	1.46	1.56	1.69	1.25
MAIFI	2.89	3.07	3.99	2.42	2.97

Although 2016 experienced relatively low reliability metric results, the recent deterioration in reliability, which started in 2017 and remains above historical levels, is consistent with the asset condition assessments noted in the ACA (Attachment C). This reliability trend is more evident in Table 2-11 below.

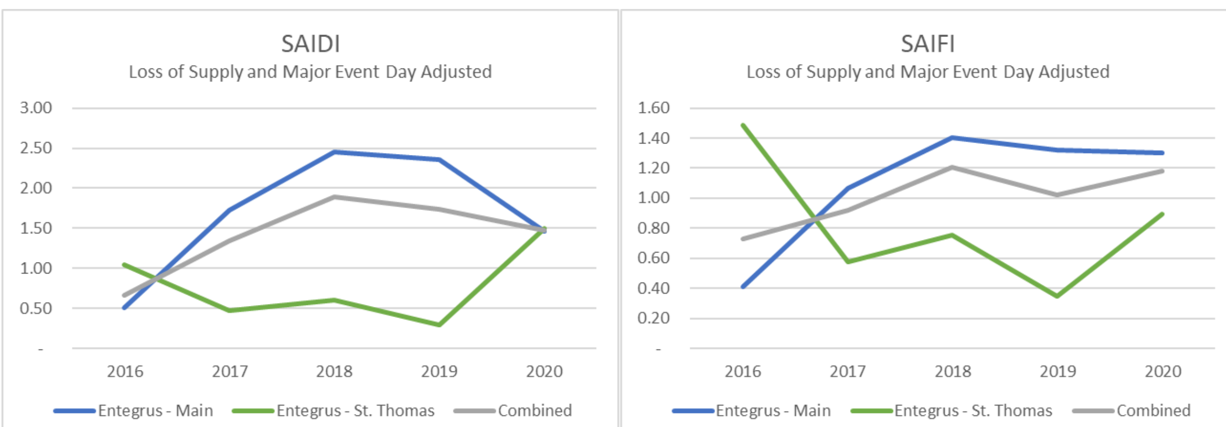
Reliability metrics are further dissected by region (rate zone), cause code below. The definition and impact of Major Event Days is also discussed.

2.3.3.1.2.1 Reliability by Rate Zone

Since Entegrus currently serves two separate customer Rate Zones that correspond to the pre-amalgamation service areas, it was determined that reliability statistics should be tracked by rate zone to provide more granular detail. It should be noted that Entegrus reliability targets are based on unified results

The Figure below graphically reproduces a portion of the above table, namely the Loss of Supply and Major Event Day adjusted SAIDI and SAIFI metrics for Legacy Entegrus and the former STEI, both ahead of, and following, amalgamation. As the figure suggests, the overall duration and frequency of outages have trended upwards in recent years, suggesting that sustained outages are on average occurring more frequently and are lasting longer relative to the beginning of the Historical Period. As noted in Section 1.5.1, Entegrus attributes this trend primarily to aging infrastructure. Enhancements to outage tracking and investigation practices have also been implemented since the previous 2016 DSP filing.

Figure 2-12: SAIDI and SAIFI Results by Rate Zone



As the figure suggests, the St. Thomas rate zone has enjoyed relatively stable reliability and lower SAIDI/SAIFI relative to the Main rate zone. This 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. In comparison, the Entegrus-Main rate zone includes 16 separate communities which are supplied from a variety of different TS's, and some outlying communities are served off long radial feeders.

It should also be noted that there is a one-time notable deterioration in Entegrus - St. Thomas' 2020 SAIDI score as the result of a single incident in August 2020. This incident resulted in a significant portion of St. Thomas customers losing power for approximately 3 hours and contributed to a 67% increase in the SAIDI score for Entegrus – St. Thomas. Although this incident did not qualify as a Major Event Day and therefore was included in the SAIDI score, had it been excluded from the metric, Entegrus – St. Thomas would have experience a SAIDI of approximately 0.50, which is consistent with historical St. Thomas SAIDI values.

Section 2.3.3.1.2.4 explores in more detail the drivers behind the observed reliability decline in the Entegrus – Main Rate Zone. Given the stable reliability performance in the Entegrus – St. Thomas Rate Zone, an equivalent discussion for St. Thomas has not been undertaken.

2.3.3.1.2.2 Historical Outage Data

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.

As noted above, the predominant contributor to these statistics is Entegrus – Main.

Table 2-8: Number of Interruptions by Cause Code (Excluding 2018 MED)

Line No.	Cause Code	2016	2017	2018	2019	2020	Total Outages	Percent Share
1	0 - Unknown / Other	18	19	15	36	25	**113**	5%
2	1 - Scheduled	119	98	145	139	62	**563**	27%
3	2 - Loss of Supply	22	39	47	58	37	**203**	10%
4	3 - Tree Contacts	36	33	43	28	42	**182**	9%
5	4 - Lightning	2	1	9	5	14	**31**	1%
6	5 - Defective Equipment	182	145	141	132	120	**720**	34%
7	6 - Adverse Weather	-	8	10	6	6	**30**	1%
8	7 - Adverse Environment	-	-	3	5	2	**10**	0%
9	8 - Human Element	3	3	1	4	3	**14**	1%
10	9 - Foreign Interference	35	49	62	59	48	**253**	12%
11	**Total**	**417**	**395**	**476**	**472**	**359**	**2,119**	**100%**

Entegrus understands that the above outage occurrences metric 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 Entegrus operating centre, and a degree of randomness.

Table 2-9: Number of Customer Interruptions by Cause Code (Excluding 2018 MED)

Line No.	Cause Code	2016	2017	2018	2019	2020	Total Outages	Percent Share
1	0 - Unknown / Other	1,510	4,675	7,675	10,336	8,644	**32,840**	6%
2	1 - Scheduled	2,529	4,078	2,826	5,643	2,955	**18,031**	3%
3	2 - Loss of Supply	15,338	63,518	50,138	57,545	34,429	**220,968**	43%
4	3 - Tree Contacts	6,171	8,053	12,092	7,470	10,788	**44,574**	9%
5	4 - Lightning	57	33	345	22	12,513	**12,970**	2%
6	5 - Defective Equipment	15,090	31,174	40,143	32,144	33,222	**151,773**	29%
7	6 - Adverse Weather	-	3,140	1,005	952	220	**5,317**	1%
8	7 - Adverse Environment	-	-	27	1,258	21	**1,306**	0%
9	8 - Human Element	14,933	615	1,195	34	5	**16,782**	3%
10	9 - Foreign Interference	1,919	1,441	4,812	3,015	3,372	**14,559**	3%
11	**Total**	**57,547**	**116,727**	**120,258**	**118,419**	**106,169**	**519,120**	**100%**

Table 2-10: Number of Customer Hours of Interruption by Cause Code (Excluding 2018 MED)

Line No.	Cause Code	2016	2017	2018	2019	2020	Total Outages	Percent Share
1	0 - Unknown / Other	937	13,194	3,431	6,112	7,293	**30,967**	4%
2	1 - Scheduled	3,069	8,721	6,068	15,813	6,515	**40,185**	5%
3	2 - Loss of Supply	20,120	82,678	95,646	97,182	45,627	**341,253**	45%
4	3 - Tree Contacts	17,115	9,254	36,074	16,764	30,211	**109,418**	14%
5	4 - Lightning	69	118	791	39	10,353	**11,370**	1%
6	5 - Defective Equipment	13,497	31,329	43,794	57,547	30,041	**176,208**	23%
7	6 - Adverse Weather	-	11,598	3,232	1,090	989	**16,909**	2%
8	7 - Adverse Environment	-	-	117	834	133	**1,083**	0%
9	8 - Human Element	1,586	998	8,285	64	9	**10,943**	1%
10	9 - Foreign Interference	2,241	2,669	7,931	4,741	3,909	**21,492**	3%
11	**Total**	**58,634**	**160,559**	**205,371**	**200,186**	**135,078**	**759,828**	**100%**

2.3.3.1.2.3 Major Event Days (“MED”)

The Entegrus Major Event reporting approach is based on the OEB reporting option (c) prescribed in the OEB guidance, the Fixed Percentage Approach. This option defines a Major Event threshold as an outage reaching the magnitude of a fixed percentage of customers affected. Entegrus has selected 10% as this threshold, as it believes this option best aligns with the customer experience and is the easiest to apply and communicate. It also provides ease of calculation in quickly determining an event’s impact and thereby assists in streamlining internal reporting.

During the Historical Period, there was one Major Event Day (“MED”) that affected Entegrus or its predecessors. The event occurred between April 14, 2018, and April 16, 2018, as a result of an ice storm that affected the three largest Entegrus communities (Chatham, Strathroy and St. Thomas). At its peak, the event left approximately 12,597 (22%) of Entegrus customers without electricity, while the total number of affected customers during the event was 16,190 or 28% of customer base at the time.

The weather event affected Entegrus' overhead system, resulting in outages attributed to the following Cause Codes: Adverse Weather, Tree Contact and Defective Equipment.

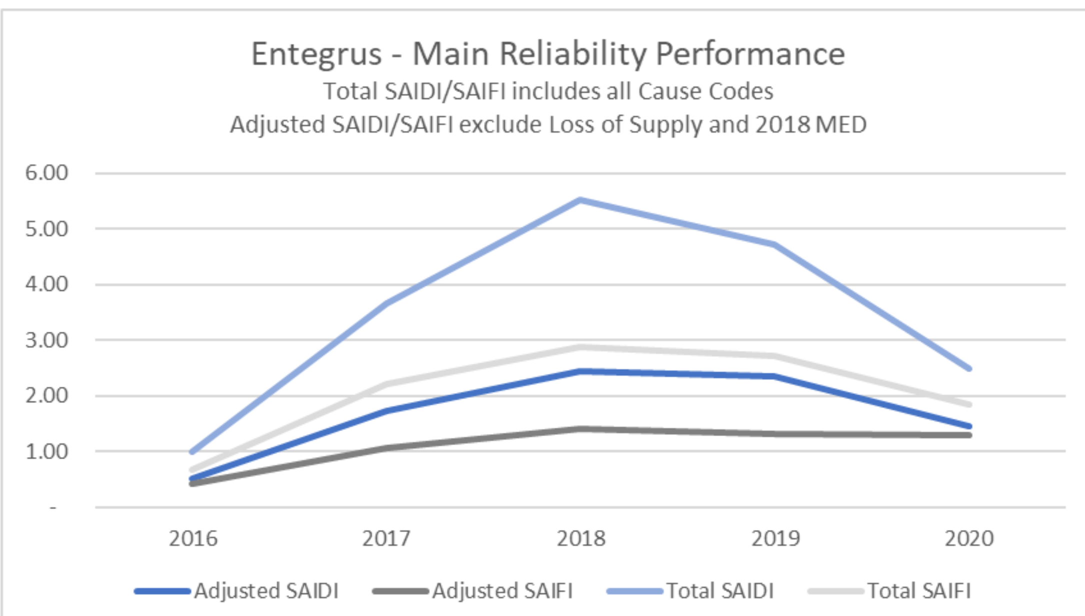
While not contributing to "loss of supply" adjusted reliability metrics, the same event also resulted in sustained Loss of Supply outages affecting Entegrus' communities of Parkhill and Ridgetown due to storm damage to the upstream supplier's assets. While Entegrus did not draw on the mutual assistance support from the neighbouring utilities, it provided mutual assistance to the upstream supplier's crews operating in the vicinity of Parkhill.

To keep its customer base informed on the progress of the restoration efforts, Entegrus issued a total of 13 Estimated Time of Restoration ("ETR") notices between April 14, 2018, and April 16, 2018. Additional information on the event is available in Attachment L, which contains the Major Event Report filed with the OEB in accordance with the Electricity Reporting and Record-Keeping Requirements ("RRR").

2.3.3.1.2.4 Entegrus-Main Historical Period Reliability Performance

Entegrus recognizes that its historical reliability performance across its pre-amalgamation service territory (referred to as "Entegrus – Main" Rate Zone) is exhibiting a deteriorating trend and warrants more discussion. Both SAIDI and SAIFI results have trended upwards over the Historical Period as isolated below in Figure 2-13.

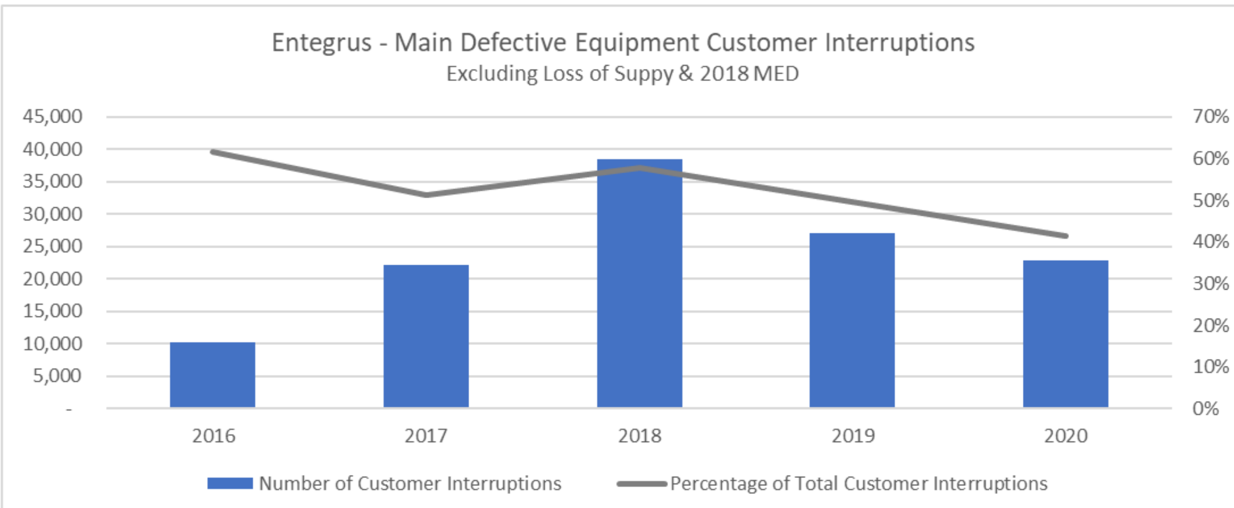
Figure 2-13: Entegrus - Main Reliability Performance

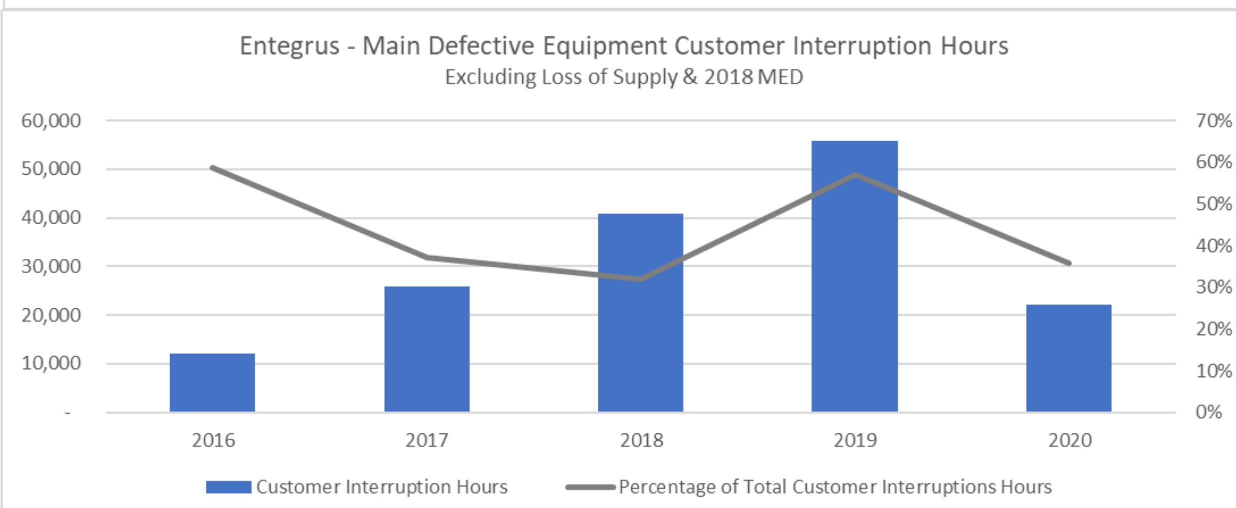


While as an embedded distributor Loss of Supply is not fully controllable by Entegrus, the Figure above shows that the impact on customers can be significant. Loss of Supply outages have historically amounted to an average of 46% of all Customer Interruptions ("CI") and 48% of all Customer Hours of Interruption ("CHI") experienced by the Entegrus – Main customers. In recognition of these impacts these type of power outages has on its customers, Entegrus and the upstream supplier have collaborated over the Historical Period to successfully reduce the impact of the Loss of Supply outages. This includes notable success stories across the communities of Wallaceburg, Tilbury, Blenheim and Ridgetown, as discussed in Section 4.4.4.5.2

In contrast, the Figure below shows Legacy Entegrus (Entegrus – Main) Customer Interruptions ("CI") and Customer Hours of Interruption ("CHI") for the Outage Cause Code considered to be most controllable and most closely related to the impact of capital and O&M work – Defective Equipment.

Figure 2-14: Defective Equipment Outages for Entegrus - Main





As the above figure indicates, when controlling for the impact of Loss of Supply and Major Event Day ("MED") events, the Defective Equipment cause code accounts for a significant proportion of Customer Interruptions ("CI") and Customer Interruption Hours ("CHI") affecting Entegrus – Main customers. While the percentages across other cause codes remained relatively stable, the magnitude of both CI and CHI for this Cause Code increased significantly in absolute terms, particularly in 2018 and 2019.

As the preceding discussion indicates, Entegrus analyzes its reliability performance in detail on an ongoing basis, in order to understand the intricacies of performance statistics across the system and identify potential ways of improving the most vulnerable performance areas.

Some improvement can be seen in the 2020 reliability numbers, which may be attributable to early returns on the recent System Renewal investment focus, as well as System Service benefits (see Distribution Automation discussion below). Ultimately, however, weather and pandemic-related factors, such as fewer scheduled outages and less foreign interference (i.e. fewer vehicle accidents impacting the distribution system), also made contributions to the 2020 results. Ultimately, the replacement of aging infrastructure to ensure customer reliability remains a key investment driver over the 2021-2025 Forecast Period, as detailed elsewhere in this DSP filing

2.3.3.1.2.5 Impact of Smart Grid / Distribution Automation

As noted throughout this document, the Historical Period investments in automated or remotely controlled switching equipment are enabling it to reduce the impact of outages on customers in specific communities. Where permitted by circuit configuration, this also includes managing the impact of any upstream supplier outages. Entegrus estimates that the Smart Grid / DA switching schemes deployed over the Historical Period helped Entegrus avoid at least 18,000 Customer Hours of Interruption ("CHI") – an amount comparable to a 2019 value of all tree-contact related outages experienced. The benefits of this technology help mitigate Loss of Supply.

As the benefits of such projects continue and as additional distribution automation devices (i.e. interties) are deployed, Entegrus expects that its customers will benefit further from these reliability-driven System Service investments. These benefits are expected to be particularly seen with the additional 2024/2025 automated switching projects intended to create dynamic distribution grids in Chatham and St. Thomas, as further described in Section 4.1.3.2. These benefits will mitigate reliability across Defective Equipment and multiple other cause codes.

2.3.3.1.2.6 Response to Recent Reliability Trends

With particular focus on the deterioration in Loss of Supply and Major Event Day Adjusted SAIDI and SAIFI, Entegrus asset planners studied system condition and its potential impact on customer reliability over the Forecast Period and beyond. The review included investment prioritization of renewal versus automation, including voltage conversion across different potential spending and reliability levels.

The review, including the percentage of key asset categories assessed as being in "Very Poor" condition in the ACA (see Attachment C), served to confirm that the deterioration in Entegrus' reliability measures required timely and proactive intervention to maintain strong focus on reliability and start to slow, or halt, the recent reliability deterioration trend before it becomes irreversible.

In summary, customer reliability remains a key investment driver over the 2021-2025 Forecast Period.

2.3.3.1.2.7 Setting Reliability Targets

Entegrus accepts that its reliability targets for the Forecast Period for SAIDI and SAIFI will be based on the standard OEB's 5-year average baseline method. Entegrus will also continue to monitor CAIDI and MAIFI.

In terms of SAIDI and SAIFI, management recognizes that the 5-year average methodology may establish a relatively low target by virtue of the inclusion of the unusually small 2016 reliability metrics included in the average. This is demonstrated by the 10-year SAIDI / SAIFI historical information shown in the Table below.

Table 2-11: 10 Year Historical SAIDI/SAIFI Results (excluding Loss of Supply and MEDs)

Line No.	Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	5-Year Average 2016-2020	4-Year Average 2017-2020
1	**SAIDI**												
2	Legacy Entegrus	0.88	1.18	1.23	1.31	1.18	0.51	1.72	2.45	2.34	1.46	1.70	1.99
3	St. Thomas	0.99	0.22	0.99	0.57	0.35	1.04	0.47	0.55	0.30	1.50	0.77	0.70
4	**Total Entegrus**		**0.90**	**1.16**	**1.09**	**0.94**	**0.67**	**1.35**	**1.89**	**1.74**	**1.47**	**1.42**	**1.61**
5	**SAIFI**												
6	Legacy Entegrus	0.72	0.97	0.94	0.84	0.87	0.41	1.07	1.40	1.15	1.30	1.07	1.23
7	St. Thomas	1.00	1.05	1.42	1.58	1.04	1.49	0.58	0.76	0.35	0.89	0.81	0.64
8	**Total Entegrus**		**0.99**	**1.08**	**1.06**	**0.92**	**0.73**	**0.92**	**1.21**	**1.02**	**1.18**	**1.01**	**1.08**

The above Table demonstrates that 2016 was a "low water mark" year for both legacy utilities in terms of both SAIDI and SAIFI. Entegrus closely reviewed its SAIDI and SAIFI results and concluded that, while the number of interruptions were relatively consistent with other years, a higher percentage of the 2016 outages were on feeders serving a relatively low number of customers.

Entegrus accepts the 5-year average methodology for establishing the SAIDI and SAIFI targets, which as shown in the Table 2-11 above, results in a 2021-2025 SAIDI target of 1.42 and 2021-2025 SAIFI target of 1.01 (excluding of MEDs and Loss of Supply). These targets will be the primary SAIDI / SAIFI metrics for Entegrus and will be shown in its RRRs and on its scorecard.

In addition to this, for internal tracking purposes only, Entegrus will also track SAIDI/SAIFI against a 4-year average. The 4-year average, a custom measure used internally only, will serve to normalize for the 2016 year and its anomalous weather conditions, and will result in additional internal tracking targets of 1.61 for SAIDI and 1.08 for SAIFI.

Impact on DSP: As noted above, maintaining reliability performance remains a key priority over the Forecast Period, and there are significant planned investments dedicated towards System Renewal in this DSP filing. As discussed above and in Section 1.5.1, reliability measures have recently deteriorated, and additional System Renewal investments are planned to remediate this. Tracking against the above-described scorecard measure based on the 5-year average SAIDI/SAIFI Loss of Supply and Major Event Day Adjusted performance targets will assist management in ensuring that 2021-2025 Forecast Period investments and other programs and mitigants are appropriately remedying aging infrastructure and enabling reliability performance. Management will also be assisted by the tracking against the custom 4-year average SAIDI/SAIFI described above.

2.3.3.1.3 Active Power Quality Investigations

Description: Power Quality was a key focus area for Entegrus ahead of its last DSP and accordingly, management established this custom measure at that time, along with a corresponding proactive program. The program surveys a portion of C&I customers every year to ensure that any potential power quality concerns are identified and resolved as expediently as possible.

Entegrus reports the number of Power Quality investigations completed during or ongoing as of December 31 of every calendar year. For the purposes of this measure an investigation is considered to be resolved when the cause of the suspected power quality issue is determined to the satisfaction of all parties involved, a preliminary path forward (if any) is identified, and no follow-up from the customer or other third parties occur within a month of the resolution.

Table 2-12: Active Power Quality Investigations Results

Description	2016	2017	2018	2019	2020
Active Power Quality Investigations	10	8	12	11	7

Impact on DSP: Historically, power quality has been an important concern for Entegrus' Commercial and Industrial Customers. Although the success of this program appears to have somewhat reduced customer demand for the service, the customer engagement process for this DSP filing again identified that power quality is a focus area for GS>50 kW customers moving forward. Accordingly, continuing to track this custom measure will help maintain focus on any emerging issues affecting this category of customers. Further, tracking power quality investigations is a prudent practice given the gradual emergence of customer-owned technologies like small-scale renewables or electric vehicles, and Entegrus' plans to deploy more Distribution Automation units that may impact the number of momentary interruptions that customers experience. Going forward, Entegrus seeks to complete 5 power quality investigations annually as sought by customers.

2.3.3.1.4 Worst Performing Feeder

Description: Entegrus established a Worst Performing Feeder ("WPF") custom reporting measure in its 2016 DSP and has reviewed the associated statistics throughout the Historical Period. The measure tracked, calculated, and monitored the average SAIDI/SAIFI of the top 5 WPF without an associated specific quantitative target.

Entegrus will continue tracking WPF measure by measuring the average SAIDI and SAIFI of the five trunk feeders with the worst SAIDI / SAIFI results during the year. The measure will exclude outages caused by Major Events or Loss of Supply Events.

Table 2-13: Worst Performing Feeder Results

Description	2016	2017	2018	2019	2020
Average SAIDI of Top 5 WPF	2.33	5.39	8.54	6.18	4.47
Average SAIFI of Top 5 WPF	1.13	3.58	4.19	2.92	2.53

Impact on DSP: Entegrus' investment plan targets improvements to system reliability through System Renewal investments as well as System Service (i.e. Distribution Automation) investments. Entegrus will continue to track and monitor this custom measure (and the feeder specifics underlying it) during the annual investment project planning cycle as an input into the identification of candidate projects. The goal of the metric is to gradually reduce the average SAIDI / SAIFI indicator of the top 5 worst feeders, thus helping improve the system's overall reliability performance in the longer term.

2.3.3.2 Cost Efficiency and Effectiveness Measures

2.3.3.2.1 DSP Implementation Progress

This metric was tracked from 2016 to 2020, both as a key DSP metric and scorecard measure.

This metric was calculated by dividing net combined Legacy Entegrus and STEI capital expenditures by the combined Legacy Entegrus and STEI DSP Plan numbers. (The STEI 2019 Plan number was extended to 2020 to align with the Legacy Entegrus 2016 DSP timeframe, as the previous STEI DSP Plan ran from 2015-2019.)

Table 2-14: DSP Implementation Results

Description	2016	2017	2018	2019	2020
Financial Project Progress vs. Plan	22.00%	44.00%	60.41%	85.60%	112.40%

That the metric exceeded over 100% at the end of 2020 is a function of: the STEI 2019 Plan number extension to 2020, inflationary pressures, the heavier than anticipated System Access work in the latter part of the Historical Period, and the need for increased System Renewal work in 2019 and 2020 beyond the original scope of the historical DSPs, as more fully described in Section 1.5.1.

Impact on DSP: Financial Project Progress vs. Plan provides a snapshot of DSP progress from a financial viewpoint which helps management recognize its headway on DSP achievement. This is also scorecard metric and Entegrus will continue to track it on an annual basis with a goal of attaining 100% by the end of 2025.

2.3.3.2.2 Planning Quality / Investment Optimization

In the Legacy Entegrus 2016 DSP, it was noted that management was investigating solutions to enhance analysis of project component level completion data, specifically relating to project quality metrics. The envisioned solution would have transferred asset management information to a comparative cost platform, which would then communicate with design estimating / job management system and the financial information system.

Work on this initiative was initially slowed due to unforeseen enhancements needed with the design estimating / job management system. Subsequently, turnover in the Distribution Engineering department, combined with the 2018 Entegrus / STEI merger and requirement thereafter to harmonize legacy systems post-merger, led to a discontinuation of the project. Accordingly, tracking of the metrics for the Historical Period did not occur.

Entegrus remains committed to tracking this metric as means by which to continuously improve planning quality and investment optimization. Accordingly, for the 2021-2025 Forecast Period, Entegrus will track and monitor the following measures. These measures align with the OEB's ongoing Activity Performance Benchmarking (EB-2018-0278) initiative, which utilizes unit cost benchmarking as its primary method of comparison and notes that such unit cost tracking allows for simplicity and ease of replication, data availability and understandability. Accordingly, management will seek to align its unit cost calculation methodologies with the OEB methodology for the following large and key capital metrics:

- Poles, Towers and Fixtures Gross Capital Unit Cost
- Transformers (excluding station transformers) Gross Capital & Unit Cost

Since these are newly defined measures and the EB-2018-0278 initiative is in progress, Entegrus does not yet have historical performance information to report.

Impact on DSP: Management will track and monitor the above-noted non-scorecard metrics. This will assist in observing and recognizing where modifications are required to ensure planning quality and investment optimization and thereby achieve sustainable long-term efficiencies to meet the DSP plan.

2.3.3.2.3 Efficiency Assessment

Entegrus takes pride in being a strong cost performer, as consistently supported by industry benchmarking results. The Entegrus Efficiency Assessment was tracked from 2016 to 2020 as a key DSP metric and scorecard measure.

The Efficiency Assessment is based on a statistical total cost benchmarking study commissioned by the OEB, which uses econometrics to make inferences on the cost efficiency of individual distributors. The Entegrus overriding goal for the Efficiency Assessment continues to be for its actual costs to be below the total costs predicted by the associated econometric model. Note that the years reference below represents the year in which the report was released by the OEB.

Table 2-15: Efficiency Results

<table>
<tr><th>Description</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th></tr>
<tr><td colspan="6">OEB Efficiency Assessment, Actual vs. Econometric Model Predicted Costs:</td></tr>
<tr><td>Entegrus</td><td>-15.4%</td><td>-13.5%</td><td>-16.8%</td><td rowspan="2">-16.0%</td><td rowspan="2">-21.0%</td></tr>
<tr><td>STEI</td><td>-10.3%</td><td>-7.7%</td><td>-14.8%</td></tr>
</table>

As noted above, Entegrus continues to be successful with its performance for this metric. Entegrus consistently resides in the 2nd of the OEB's Efficiency Cohorts, which includes distributors whose actual operating costs are 10%-25% lower than the "average efficiency" cost levels predicted by the OEB's econometric model.

The 2020 assessment found that Entegrus' 2019 costs were 21% below the econometric model's predicted costs. This result is particularly notable since the Entegrus / STEI merger occurred on April 1, 2018, and 2019 represented the first full year of post-merger integrated operations.

In the 2020 assessment, Entegrus had 15th lowest Total Cost per Customer in the province, and the 25th lowest Total Cost per km of the Line.

The Table below contains the details used in the calculation of the Appendix 5-A cost metrics requirements.

Table 2-16: Entegrus Unit Costs by Year

Line No.	Category	Description	2016	2017	2018	2019	2020
1	$000's	CAPEX	$9,351	$9,820	$10,420	$10,559	$13,176
2		O&M	$4,158	$3,916	$3,946	$4,341	$3,963
3		Total	$13,509	$13,736	$14,366	$14,900	$17,139
4	Stats	Number of Customers	58,079	58,661	59,186	59,810	60,589
5		km of Line	1,195	1,236	1,243	3,083	3,043
6		MW Demand	190.899	184.785	184.558	190.625	188.191
7	Cost Metrics	Total Cost per Customer	$233	$234	$243	$249	$283
8		Total Cost per km of Line	$11,304	$11,113	$11,557	$4,833	$5,632
9		Total Cost per MW	$48,985	$53,144	$56,458	$55,392	$70,012
10	CAPEX Metrics	Total CAPEX per Customer	$161	$167	$176	$177	$217
11		Total CAPEX per km of line	$7,825	$7,945	$8,383	$3,425	$4,330
12	O&M Metrics	Total O&M per Customer	$72	$67	$67	$73	$65
13		Total O&M per km of Line	$3,479	$3,168	$3,175	$1,408	$1,302

As per the filing requirements, the unit costs metrics as prescribed by Appendix 5-A, are shown below.

Table 2-17: Entegrus Unit Costs, Appendix 5-A

Line No.	Metric Category	Metric	Measures	
			2020 Actual	5 Year Average
1	Cost	Total Cost per Customer	$283	$249
2		Total Cost per km of Line	$5,632	$7,515
3		Total Cost per MW	$70,012	$56,786
4	CAPEX	Total CAPEX per Customer	$217	$180
5		Total CAPEX per km of line	$4,330	$5,441
6	O&M	Total O&M per Customer	$65	$69
7		Total O&M per km of Line	$1,302	$2,074

The increased System Renewal investment focus described in Section 1.5.1, as well as pandemic-related impacts, are apparent in the 2020 measures above. More specifically, the increased System Renewal investment focus has driven an increase in 2020 as compared to the 5-year average.

It should be noted that the unit cost metrics shown above differ from the unit costs shown on the scorecard due to additional calculations within the scorecard to "right-size" the metrics to allow for comparability between LDCs.

Impact on DSP: The above-noted Efficiency Assessment, Cost per Customer and Cost per km of Line metrics are important in order for management to gauge progress throughout the Plan period, as well as ensuring investment efficiency. Despite the increased focus in System Renewal investment, Entegrus expects to be able to balance increased the increased investment focus while maintaining lower costs than anticipated by the benchmarking model over the Forecast Period. Management recognizes that this balance is congruent with managing customer distribution rates and bill impacts. Entegrus will continue to track these metrics for 2021-2025 and will continue to seek lower-than-anticipated benchmarking costs.

2.3.3.3 Asset and System Operations Performance Measures

2.3.3.3.1 Line Losses

Description: Entegrus originally introduced this measure in its 2016 DSP. Line losses are calculated as the percentage of electrical energy lost, due to heat and transformer losses, in the transmission of electrical energy from Entegrus' supply points to its customers. Losses will be calculated as the difference between the total kWh purchased and the total kWh delivered within in a calendar year. The final metric will be expressed as a ratio of kWh of losses to the total kWh purchased.

Entegrus does not have a target for this metric but strives to see a year-over-year decrease, while recognizing that a variety of factors and randomness can contribute to annual results.

Table 2-18: Line Losses Results

Description	2016	2017	2018	2019	2020
Losses as a Percentage of Total Purchases kWh	4.11%	3.43%	3.58%	4.18%	3.91%

Impact to DSP: Voltage Conversion is among Entegrus' largest investment programs planned over the 2021-2025 timeframe. One of the benefits of the program is the reduction of losses associated with lower-voltage conductors and distribution substations that will become redundant once line equipment conversions in each local area reach completion. See Section 1.4.7.2 for additional discussion. Entegrus will continue to track this RRR information and custom metric for 2021-2025 and will continue to seek year-over-year decreases.

2.3.3.3.2 Defective Equipment Reliability

Section 2.3.3.1.2 outlines the extent to which Defective Equipment-caused outages have contributed to Entegrus' reliability performance, particularly in the Entegrus – Main Rate Zone. With System Renewal work as a major investment priority for Entegrus for the 2021-2025 Forecast Period, measurement of Defective Equipment Reliability serves to track operational performance in terms of the DSP. It will also enhance management's understanding of the types of equipment that are most susceptible to failures or malfunctions, and/or circumstances in which these events occur.

The impact of outages caused by defective equipment have trended upwards recently, as shown in Table 2-10. Equipment failures are primarily due to deteriorated assets, an increasing number of which are now beyond repair, nearing end of life, or in "Very Poor" condition. This is corroborated by the ACA (Attachment C), which determined the following "Very Poor" asset category percentages: Wooden Poles (25%), Submersible Transformers (22%), Overhead Transformers (20%), Substation Ground Grids (43%) and EPR / XLPE Cable (25%). As noted, a key emphasis of this DSP filing is to mitigate aging infrastructure through focused investment in System Renewal, specifically to address assets at risk of failure due to their condition.

To this end, Entegrus is working to formally establish a framework of Sub-Cause Codes for Defective Equipment outages, leveraging in part the experience of the former STEI with this measure. This framework would enable response personnel to identify what major type of equipment caused an outage and give asset managers additional objective planning information. Accordingly, Entegrus will adopt and monitor annual performance for the 2021-2025 Forecast Period on a custom reliability metric related to defective equipment. This metric will track the subset of SAIDI and SAIFI (excluding Loss of Supply and Major Event Days) by rate zone attributable to the Defective Equipment outage cause code. The SAIDI/SAIFI methodology will remain the same as described above in Section 2.3.3.1.2 with the exception being that only Defective Equipment cause code outages will be tracked in the numerator.

Since this is a newly defined measure, Entegrus does not have historical performance information to report.

Impact to DSP: The enhanced understanding of the relationship between the age, condition and type of equipment that fails across the distribution system, will help Entegrus refine its planning assumptions, most notably those related to the probability of asset failure. Thus, this custom metric is not only an Asset and Systems Operations Performance metric, but also an indicator as to the efficiency and effectiveness of DSP implementation over the 2021-2025 Forecast Period. The data collected to support this measure will help Entegrus to identify any emerging trends across specific asset classes or age/condition cohorts and improve the quality of assumptions underlying its risk-based asset management tools.

2.3.3.4 Safety Measures

Entegrus relies on a framework of five Core Values to drive strategic and operational decision-making. Safety is the first and most fundamental Core Value, as exemplified by the statement, *"Safety first in everything we do".*

Entegrus' longstanding fundamental safety focus was further reinforced by the 2016 electrical contact accident described in Section 1.5.1. As noted, the accident prompted a thorough revaluation of Entegrus' safety systems and processes and resulted in recognition of the need for additional System Renewal focus.

2.3.3.4.1 Level of Compliance with O. Reg 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 of 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. Entegrus seeks to be fully compliant with O. Reg 22/04.

Table 2-19: Level of Compliance with O. Reg 22/04 Results

Description		2016	2017	2018	2019	2020
Level of Compliance with O. Reg 22/04	Entegrus	C	C	NI	C	C
	STEI	C	NC			

A key focus arose out of the former STEI's 2017 O. Reg. 22/04 audit, which found the former STEI to be non-compliant with the regulation due to the issues involving inspection document management, testing of spare transformer equipment and maintenance of the major electrical plant in service list. These findings were addressed in 2018 and 2019. Thereafter, O. Reg. 22/04 compliance has been assessed as compliant, starting with the 2019 audit.

Impact to DSP: Compliance with O. Reg 22/04 helps ensure public safety and serves as a DSP quality indicator. This is both an ESA and scorecard metric and Entegrus will continue to track O. Reg 22/04 audit results of the 2021-2025 Forecast period and will continue to target annual assessments of "compliant". Entegrus recognizes that any audit findings represent opportunities represent opportunities for improvement which will be embraced.

2.3.3.4.2 Non-Occupational Serious Electrical Incidents

Description: The Non-Occupational Serious Electrical Incident Index metric is a component of the public safety measure and is intended to address the resultant impact in improving public electrical safety on the distribution network over time. It measures the number of, and rate of serious electrical incidents occurring on a distributor's system. Entegrus seeks to observe no such incidents per year.

Table 2-20: Non-Occupation Serious Electrical Incidents Results

Description	2016	2017	2018	2019	2020
Non-Occupational Serious Electrical Incidents	-	-	2	1	4

It should be noted that electrical incidents are reported on a one-year lag for the purpose of this scorecard metric. While neither predecessor had a non-occupational electrical incident in the years prior, two events involving members of the public occurred in 2017, which are shown in 2018 as per reporting requirements. One of these incidents involved a motor vehicle collision with an Entegrus pole. The other incident occurred when a member of the public (not working for Entegrus), was performing vegetation management work near energized equipment. In 2018, another incident occurred (reported as per requirements in 2019), involving a motor vehicle accident that caused broken poles and downed overhead wires.

In accordance with its foremost core value of Safety, starting in 2019, Entegrus instituted a process to ensure deeper reporting of electrical incidents involving the public, based on the ESA's updated Guideline for Section 12 of Ontario Regulation 22/04: Electrical Distribution Safety Reporting of Serious Electrical Incidents. Accordingly, for 2019 (reported as 2020 above), Entegrus reported 4 incidents. The first incident involved the failure of a degraded hydro pole. The other three incidents involved weather-related vegetation contacts with overhead conductor, all of which resulted in the conductor being isolated before failure.

Entegrus' staff have examined the circumstances surrounding these incidents and incorporated their insights into the content of relevant employee safety training and public safety awareness programs. These programs include periodic radio and media public safety messages, as well as Entegrus providing training to Fire, Police and EMS on approaching emergency downed-wire situations. The 2019 incidents (reported as 2020 above) reinforced the ongoing importance of vegetation management, as well as the need for replacement of aged and deteriorated assets, which is a key focus of this DSP filing.

Impact to DSP: Learnings from non-occupational serious electrical incidents is an ESA metric and incorporation of associated insights is vital to ensure public safety. This is also a scorecard metric and Entegrus will continue to track it through the 2021-2025 Forecast Period. Entegrus will continue to seek to observe no such incidents per year, while recognizing that the nature of most public incidents, along with recent changes to the process by which Entegrus reports to the ESA, may limit the ability to meet this goal. As noted above, the key will be to incorporate learnings to ensure public safety.

2.3.3.4.3 Lost Time Hours

Description: Lost time hours is an industry measure used to measure employee safety in the workplace. The measure specifically focuses on injuries or illness triggered from the workplace which results in employee time off from work after the incident.

As previously noted with respect to Core Values, Entegrus treats safety of its employees (as well as contractors and the general public) as the number one priority. Entegrus strives to maintain zero employee lost time hours each year.

Table 2-21: Lost Time Hours Results

Description	2016	2017	2018	2019	2020
Lost Time Hours	1,399	32	108	-	-

The impact of the 2016 electrical contact incident can be seen above. Putting aside metrics, management is relieved and grateful that both injured employees later recovered and continue to work for Entegrus. Management recognizes that the risks associated with the electrical distribution industry and will continue to maintain a strong focus on Health and Safety.

Impact on DSP: The tracking of Lost Time Hours is integral to the foremost Entegrus core value of Safety. As previously noted, Entegrus' long-time focus on safety (as described above), was further reinforced by the impact of the 2016 electrical contact accident and led to a re-evaluation of Entegrus' safety systems and processes and recognition of the need for additional System Renewal focus. The custom metric of Lost Time Hours will continue to be tracked and Entegrus will continue to strive to maintain zero employee Lost Time Hours each year.

2.4 Realized Efficiencies due to Smart Meters (5.2.4)

Filing Requirements 5.2.4: Since 2006, distributors have deployed smart meters for residential and small industrial and commercial customers. This initial deployment has been completed and smart meters have been in operation for a number of years. Distributors are also required to deploy metering inside the settlement timeframe (MIST) meters to applicable GS > 50 kW customers by December 31, 2020.

A distributor is required to document capital and operating efficiencies that it has realized as a result of the deployment and operationalization of smart meters and related technologies (e.g., Advanced Metering Infrastructure (AMI) communications networks, Operational Data Storage) in its networks, such as, for example, if smart meter and AMI "last gasp" technology enhances a distributor's SCADA system to assist in restoration response to service interruptions. Both qualitative and quantitative descriptions and support should be provided.

Entegrus' predecessor utilities were among the early adopters of smart meters, with the technology already having been assessed internally prior to the Ontario government's May 2004 industry implementation announcement. Entegrus was among 13 licensed distributors authorized by Ontario Regulation 427/06 to carry on discretionary smart metering activities and commenced deploying smart meters starting from a November 2004 pilot. Since the time of smart meter deployment, Entegrus' current service territory has seen multiple M&A transactions as described in Section 1.3. Considering the diversity of historical approaches to format, granularity, and availability of data across its multiple predecessors, it would be impractical for Entegrus to attempt to estimate the quantitative impact of smart meter-related efficiencies.

In general, however, the deployment of smart meters enabled Entegrus and its predecessors to accomplish the following important objectives:

- **Revenue Lag Reduction**: the elimination of time lag between the meters being read in the field and being processed by the billing function has reduced the length of time between the utility incurring costs and receiving revenues to cover them. This reduction has, in turn, led to the reduction of the Working Capital Allowance and a lower rate trajectory.

- **Fleet Expenditures Rationalization**: the reduction of truck rolls required for reading of analog meters led to lower fuel and maintenance expenditures, and enabled Entegrus to rationalize its fleet requirements during successive rounds of post-amalgamation optimization activities.

- **Service Quality Enhancements**: while smart meters freed up considerable time on the part of staff involved in meter data reading and processing, the timing of their implementation coincided with the beginning of an increased focus on service quality and reliability performance across the industry. Entegrus was able to channel the labour resources freed up by smart meter deployment towards performance improvement initiatives in data collection, reporting and performance management across many of these important areas of focus.

- **Reliability Data Capturing**: the “last gasp” capability available on all Entegrus meters enable the Control Room to identify and calibrate power outages virtually in-real time and notify the response crews without waiting for customers to notify the utility of an outage by phone. The “last gasp” feature is a key input to the Entegrus online outage map system.

3 ASSET MANAGEMENT PROCESS (5.3)

The asset management process is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus.

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

This section provides an overview of Entegrus' asset management process, a description of assets that make up Entegrus' system, and the tools and processes underlying the asset lifecycle optimization work. Overall, this section aims to articulate the main issues characterizing Entegrus' 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.

3.1 ASSET MANAGEMENT PROCESS OVERVIEW (5.3.1)

The distributor must provide the OEB and stakeholders with a high-level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan.

3.1.1 Asset Management Objectives (5.3.1a)

A description of the distributor's asset management objectives and related corporate goals, and the relationships between them, including an explanation of how the distributor ranks asset management objectives for the purpose of prioritizing investments.

Entegrus' Asset Management ("AM") Objectives articulate the main forms of value that it expects to provide to its customers, staff and shareholders by operating and modifying its asset base over time. The objectives are in place to help Entegrus asset managers evaluate whether and how their investment decisions, or changes to the AM process itself, position the utility to achieve its core value outcomes into the future.

Entegrus' AM objectives are grounded in Entegrus' overall Corporate Values framework, ensuring alignment of key decision-making principles across all facets of operations. Each of the six individual AM objectives is assigned a specific weighting, determined by Entegrus' executives to help asset managers make trade-off decisions between potential investment candidate activities or AM process improvements. 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. Table 3-1 presents Entegrus' AM objectives, along with their relationship to the utility's Corporate Values, Key Performance Indicators, and their relative weighting used to inform investment activities prioritization.

Table 3-1: Entegrus' Asset Management Objectives

AM Objectives	Articulation of Objectives	Relevant Corporate Values	Related KPIs	Prioritization Weighting
Public 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** first in everything we do.	• Non-Occupational Serious Electrical Incidents	5
Employee Safety			• Lost Time Hours	5
Environment	Continuously explore and execute on ways to manage the impact of Entegrus' asset base and operating activities on the natural environment.	• Delivering **Sustainable Growth** for our stakeholders. • **Safety** first in everything we do.	• System Losses Reduction	4
Reliability	Deploy an optimal mix of System Renewal, System Service and O&M solutions to minimize the duration of power outages experienced by Entegrus customers, including those occurring due to loss of upstream supply.	• Exceeding the needs of customers and the communities we serve, by having a **Customer and Community focus**. • Achieving **Operational Excellence** by always striving for continuous improvement.	• SAIDI • SAIFI • Worst Performing Feeders	3
Operational Efficiency	Continuously explore and execute on opportunities to reduce the labour-intensive components of Entegrus' capital and maintenance work through investments in new technology and managerial innovation.		• OEB Efficiency Assessment	2
Cost Effectiveness	Deploy new capital in a manner that seeks to minimize asset lifecycle costs across all utility functions.	• Delivering **Sustainable Growth** for our stakeholders	• Planning Quality: Actual vs. Budgeted Project Costs	3

While Entegrus retained the concept of relative weightings associated with individual AM Objectives, the manner in which it relies on this framework has changed since the 2016 DSP. In preparing the 2016-2020 DSP submission, planners manually scored individual System Renewal and System Service candidate projects using the above framework to determine the optimal sequencing of investments. In delivering the current 2021-2025 DSP, planners leveraged a more data-driven, and automatically administered risk-based prioritization approach on a system-wide level, as described in Sections 3.1.2 and 3.3.

This approach enabled Entegrus to identify an initial list of asset intervention opportunities with the highest potential of reducing asset lifecycle costs. Having performed the first tier of prioritization, planners then used the relative weightings of individual AM Objectives to ensure that ultimate project selection reflected site-specific considerations, customer preferences, and/or broader managerial and policy objectives that cannot be reasonably captured through automated scoring. This two-pronged approach enabled Entegrus planners to rely on objective and granular automated analysis to scan the system and "predict" the best investment opportunities, and then apply expert managerial and technical judgment to refine the predicted list.

3.1.2 Components of the Asset Management Process (5.3.1b)

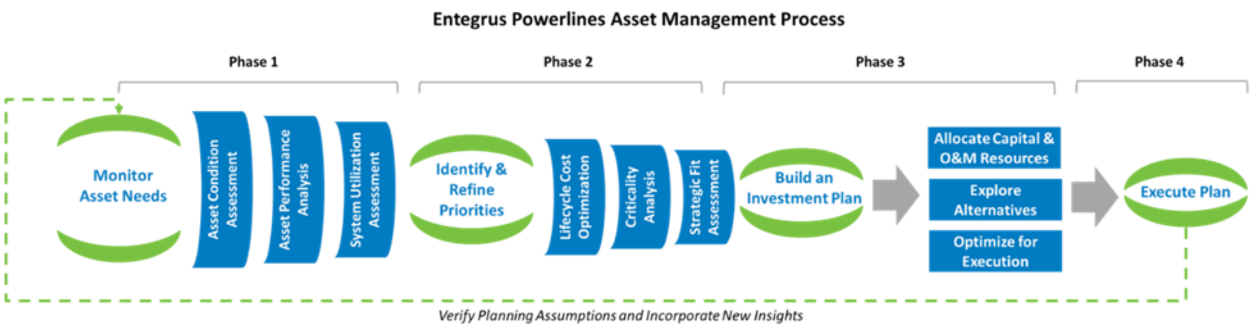
Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, including the identification and description of the data, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments, for example: Asset register, asset condition assessment, asset capacity utilization/constraint assessment, historical period data on customer interruptions caused by equipment failure, reliability-based 'worst performing feeder' information and analysis, and Reliability risk/consequence of failure analyses.

Use of a flowchart illustration accompanied by explanatory text is recommended.

This section describes the nature and sequencing of tools and processes Entegrus uses to collect, analyze and operationalize information that informs its asset intervention decisions. See Section 3.3 for the discussion of specific policies and principles underlying the use of these tools and processes.

Figure 3-1: Entegrus Asset Management Process depicts the key functional elements of Entegrus' Asset Management process. As the graphic indicates, the overall process entails a constant information feedback loop assessed and refined though dedicated tools and processes that enable Entegrus 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 3-1: Entegrus Asset Management Process



Phase 1: Asset Needs Monitoring

The first phase of the AM Process attempts to capture the information on the current state of Entegrus' 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:

- 1.1 Asset Condition Assessment
- 1.2 Asset Performance Analysis
- 1.3 System Utilization Assessment

1.1 Asset Condition Assessment

Entegrus 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, Entegrus gains a critical input that helps it plan the types, volumes, and timing of future asset intervention activities.

Entegrus performs several major types of Asset Condition Assessment ("ACA") work that vary in their frequency, formality and types of equipment targeted:

- *System Assets ACAs* – quantitative assessments of health of Entegrus' major electrical system assets using results of field inspection and testing activities. The results of the latest System Assets ACA performed by METSCO are described in Section 0;

- *Metering Assets Verification Work* – regular cyclical or reactive activities in response to customer requests undertaken to verify the accuracy of Entegrus' revenue meters discussed in 4.4.5.3.3;

- *Fleet Assets Inspection Work* – evaluation of mechanical and structural integrity of Entegrus' vehicles and other rolling stock in the course of regular or reactive maintenance discussed in Section 3.3.5;

- *Facilities Assets Inspection Work* – evaluation of structural integrity, observable wear and tear and other deficiencies of Entegrus' buildings and key building systems discussed in Section 3.3.4; and

- *IT Asset Lifecycle Evaluation* – assessment of whether and how the deployment of Entegrus' software and hardware assets aligns with the utility's IT Asset Management strategy discussed in Section 3.3.3.

As discussed in Section 2.1.6.2, Entegrus stores all system 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. Entegrus staff capture condition information associated with other types of assets in a variety of dedicated tracking and reporting tools.

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.

Entegrus gathers system performance information through a variety of activities:

- *Reliability Monitoring*: tracking of duration, frequency and causes of electrical service interruptions experienced by Entegrus customers.

  While it historically tracked its outage causes using the standard Canadian Electricity Association ("CEA") Cause Codes, the best practices exchange in the process of integration with STEI exposed Entegrus to the benefits of tracking more granular sub-cause codes as well, particularly with respect to Defective Equipment outages. Entegrus is currently exploring the rollout of such sub-cause code tracking framework across its service territory in 2021. Section 2.1.6.2 discusses the improvements Entegrus already undertook to its reliability tracking capabilities since the time of its previous DSP filing.

- *Power Quality Monitoring*: as described in Section 2.1.6.2, Entegrus has taken significant steps to investigate and resolve the power quality concerns identified by its customers and maintains an ongoing program that proactively surveys its largest customers as to the evidence of any emerging power quality concerns.

- *System Loss Monitoring*: Entegrus targets electrical loss reductions through its continued investments into voltage conversion projects across its service territory. While voltage conversion carries a number of benefits beyond loss reduction, Entegrus 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 Section 0, Safety and Environment are among Entegrus' 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 Entegrus regularly receives from its customers, contractors, neighbouring transmitters / distributors, municipalities, 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*: Entegrus regularly reviews a variety of formal and informal operating metrics that track performance 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 Entegrus 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.

1.3 System Utilization Assessment

Whereas the previous two steps inform Entegrus as to 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*: Entegrus' Conditions of Service prescribe the steps that it 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 Entegrus track the rates at which formal connection applications and informal inquiries across different asset classes materialize into actual customer additions. This analysis helps Entegrus calibrate its longer-term System Access requirements and provides an input into its load forecasting activities.

- *Load Forecasting Work*: Entegrus publishes five-year forecasts of station peak load for all three of its system "sub-regions" (Chatham, St. Thomas, Strathroy), updating them as required by the regional planning processes or other emerging needs. From time to time, and as required by the Regional Planning process activities described in Section 2.2.3, Entegrus collaborates with Hydro One and/or IESO to develop longer 10-year load forecasts for parts of its system involved in an active regional planning undertaking. See Section 4.2.2 for additional details on Entegrus' current load forecasting work.

- *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, Entegrus periodically analyzes the opportunities to accommodate new load and/or defer potential system capacity expansion work through load transfers on its distribution system. See Section 3.2.4 for additional information on Entegrus' system utilization assessment work.

- *General Plant Assets Utilization Analysis*: Entegrus 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). As discussed in Section 2.1.3.2, the amalgamation with STEI provided an opportunity to explore and eliminate a number of cost drivers that were made redundant as a result of the transaction.

In summary, the first phase of Entegrus' AM Process aggregates the initial evidence on the total range of known and forecasted asset needs over the next five-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.

Phase 2: Identify and Refine Priorities

The second phase of Entegrus' 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 Entegrus' strategic values. This phase consists of three elements:

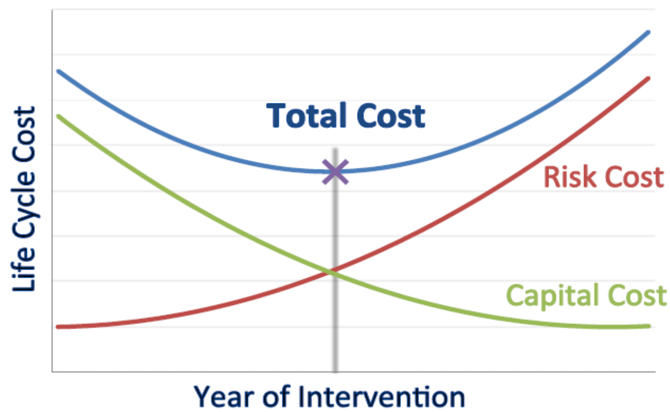
- 2.1 Lifecycle Cost Optimization
- 2.2 Criticality Analysis
- 2.3 Strategic Fit Assessment

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.

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, Entegrus seeks to execute its asset intervention activities in alignment with lifecycle cost minimization principle captured in the Figure 3-2.

Figure 3-2: Asset Lifecycle Minimization Approach



The above figure showcases three curves: an annualized capital cost of an existing asset shown by the light green curve, an annualized risk cost inherent in the same asset shown in red, and the total lifecycle cost curve which is the sum of the two other curves which is shown in light blue. As the utility and its customers derive the expected economic value from an existing asset over time, its annualized cost gradually declines. At the same time, the longer that the asset remains in service – the higher is its likelihood (probability) of failure or other type of malfunction. The product of the increasing failure *probability* and the economic *impact* brought about by the failure (direct costs to the utility to rectify the failure, and indirect costs experienced by customers and the society) is the *risk cost* associated with that asset.

Aside from reactive expenditures to rectify in-service asset failures, the increasing risk cost curve also captures the higher maintenance expenditures associated with an older or more degraded asset. In the context of electric system plant, these may represent higher expenditures to locate spare parts of an outdated piece of equipment or major transformer overhauls. For an IT asset, this may involve commissioning software patches or paying for reactive support by third parties after regular vendor support ends. In the case of Fleet or Facilities assets, this represents more comprehensive overhauls or refurbishment activities that may extend an asset's lifecycle by a fraction of the economic life of a newly commissioned asset.

Given the combination of a declining annualized capital cost and the increasing annualized risk cost of a given in-service asset, the economically optimal time to replace that asset is at the point where the two curves intersect. As the Figure 3-2 shows this, intersection corresponds to the lowest point on the light blue total lifecycle cost curve marked by an "x".

It is important to note that Entegrus operationalizes the above asset lifecycle cost management logic to establish the optimal volumes of replacement investments and outlined the anticipated sequencing of its asset intervention needs relative to one another, rather than determine the exact timing of intervention for any given asset, due to the size of its annual System Renewal portfolio and the number of potential investment candidates.

Electrical System Plant Lifecycle Cost Analysis

For the 2021-2025 DSP planning work, Entegrus was able to enhance lifecycle cost analysis by incorporating the industry failure probability distribution data (asset failure curves), and the detailed estimates of both the direct utility costs and the indirect cost estimates associated with customer impact based on the Customer Interruption Cost ("CIC") studies available through the Interruption Cost Estimate ("ICE") Calculator database sponsored by the U.S. Department of Energy.[9]

Prior to executing the asset lifecycle cost analysis, Entegrus asset managers reviewed the input parameters for the asset failure probability curves and the CIC estimates used in the model, to confirm their general alignment with the conditions of Entegrus service area. While the volume of Entegrus' own asset failure records and the cost of performing utility-specific CIC studies required Entegrus and METSCO to rely on industry data, both failure curves and interruption cost estimates underwent local SME validation prior to use. Overall, the utility sees the use of the more extensive utilization of the risk-based planning methodology as a significant step forward, as it entails the consideration of the full scope of value created by electricity service – in a consistent manner across all electrical system assets and customer locations. See Section 3.3.2 for additional information on the analytical work performed.

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 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 3.3 for more information regarding these policies and practices.

2.2 Criticality Analysis

Entegrus 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 Entegrus 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. By pursuing investments deemed to be more critical relative to other potential

[9] https://icecalculator.com/home, accessed April 20, 2020.

candidates, Entegrus seeks to reduce the aggregate risk inherent in its system's status quo. There are several ways in which Entegrus undertakes criticality-based prioritization:

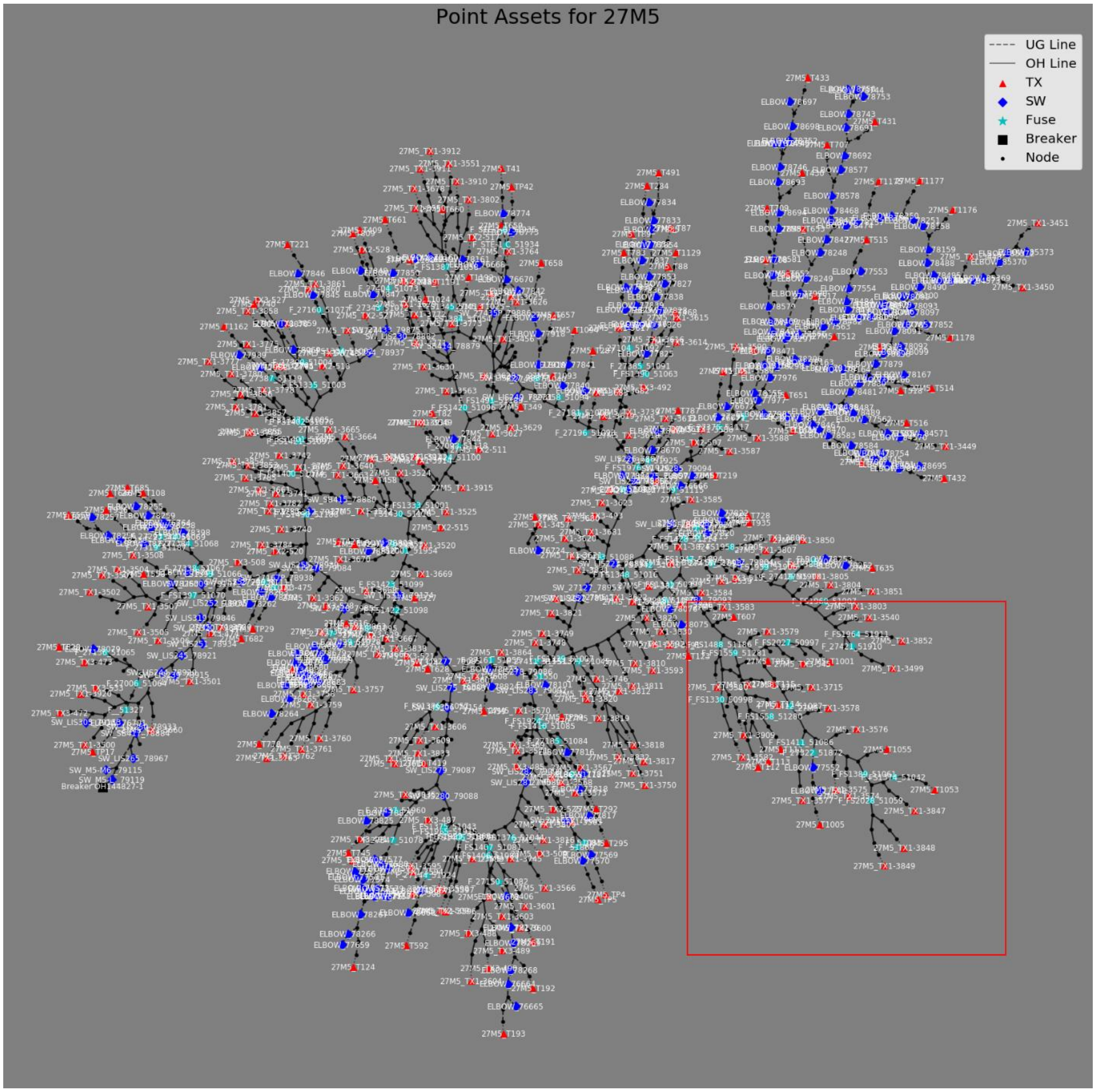
- *Safety Related Criticality:* capital investments or operational activities targeting reduction of public and/or safety risks are assigned the highest criticality across all asset classes and are usually executed without delay.

- *Compliance-based Criticality*: activities prescribed by law, industry codes or conditions of Entegrus' distribution license are considered as more critical than activities where Entegrus has discretion over the scope and/or timing of work. For example, Entegrus allocates funding to the anticipated System Access investments without carrying out any prioritization activities relative to other types of investments. In the event where 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 that it maintains compliance with the conditions of its Distributor License.

- *Electrical Connectivity Criticality:* other things being equal, assets located higher upstream on feeders that lack interconnection points downstream are automatically assigned higher criticality in the asset lifecycle cost analysis. For example, the assets located in the upper left corner of the red square in the Figure 3-3 which depicts an Entegrus feeder, are seen as more critical than those located further down the feeder. 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 towards the bottom right of the red square would leave less customers without power.

- *Equipment Type Criticality*: outages of different types of assets require different amount of time and effort to rectify. Consequently, a potential catastrophic failure of a station transformer is seen as more critical than a potential catastrophic failure of a pole-top transformer in the lifecycle cost prioritization analysis.

Figure 3-3: Connectivity Analysis of a Feeder in St. Thomas



Customer Load Type Criticality: Entegrus recognizes that different types of customers value the cost of power interruption in a different way. Recognizing this fact, the ICE Calculator values underlying the AM analytics use different cost interruption values for the occurrence and duration of outages for different customer classes. Consequently, a hypothetical mid-week outage that interrupts 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 sensitive 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 Entegrus' IT, Fleet and Facilities assets generally follows the same principles as the work that considers electrical plant. The SMEs 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 Entegrus' 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.

2.3 Strategic Fit Assessment

The final dimension of prioritization work that supports Entegrus' asset intervention planning involves consideration of potential investments against the utility's Asset Management Objectives described in Section 0. While most elements of the prioritization work described above are aligned with Entegrus' 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 largely entail formulaic application of economic principles and/or technical considerations. In contrast, this dimension of planning work enables the use of managerial judgment by SMEs in a structured manner that reflects the balance of strategic priorities set by the Executive. Considering the complexity characterizing electric utility planning and work execution, Entegrus 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.

Phase 3: Constructing the Investment Plan

The third phase of Entegrus' AM Process entails preparation of annual Investment Plans using the insights collected through analytical work described above, and the 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

Entegrus' 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 focussed 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:

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

These stages are described in more detail in Section 4.3 that describes the specifics of the Capital Investment Planning Process. The subsections below provide brief summaries of the underlying objectives and activities.

3.1 Allocating Capital and O&M Resources

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

- macroeconomic outlooks for Canada, Ontario and the province's southwestern region;
- the outcomes of regional planning work concerning Entegrus and its assets;
- shareholder guidance gathered through ongoing consultations;
- capital needs outlooks developed through earlier phases of the AM Process;
- load growth and customer growth forecasts;
- commitments made by Entegrus 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 the optimal way allowed by the funding envelope.

With top-level budget constraint having been applied to their departmental budgets, Entegrus' 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.

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, Entegrus 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. Other alternatives that Entegrus planners consider depend on a type of an asset undergoing intervention, the party performing the work, the length of completion and materiality of an underlying investment, and others.

Where relevant, Entegrus 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, some options analysis may take place by the field crews in the course of executing the work, where unanticipated difficulties or opportunities to realize incremental value emerge in the course of completing the work. Entegrus attempts to limit the opportunities for these 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 (if deemed 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.

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.

Phase 4: Executing the Plan

The final component of Entegrus' 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 Entegrus' crews and/or other individuals executing the work and the types of tools, equipment and other implements available to undertake the work.

As noted in Section 2.1.6.4, Entegrus made a number of notable enhancements to its capabilities supporting work execution since the 2016 DSP filing and is targeting further improvements over the Forecast Period. An area of particular interest for Entegrus' electrical system construction work is the detailed reconciliation between detailed planning cost assumptions underlying project budgets and the actual costs of completed work. This facet of managerial improvement targeted over the Forecast Period is consistent with the feedback loop element that connects the last and the first phases of the AM Process diagram presented in Figure 3-1, to emphasize the importance of continuous review, validation and re-calibration of assumptions supporting the analytical work throughout the AM Process.

3.2 Overview of Assets Managed (5.3.2)

Assessment of DSPs requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment and others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed

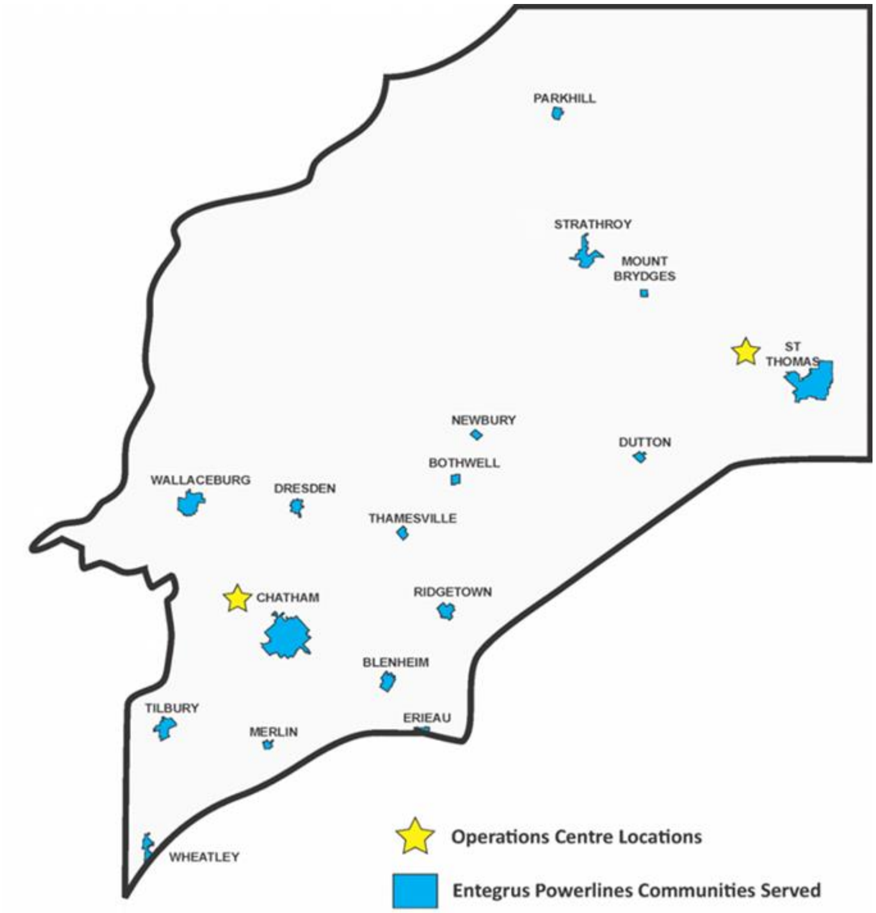
The information in this section contextualizes Entegrus' asset management work by describing the current state of Entegrus' power system, including its geographical location, electrical configuration, and the state of its major asset classes.

3.2.1 Description of the Service Area (5.3.2a)

A description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DSP. A distributor may provide more detailed geographic and/or engineering maps where these may help reviewers better understand specific application components, such as the distributor's capital expansion or replacement programs, its network assets such as transformer stations, and its interconnections with other transmitters, distributors and generators (e.g. such as for host or embedded distributor connection).

Entegrus delivers electricity across 132 km² of urban service area, made up of 17 separate communities. The communities Entegrus serves are dispersed across an area of more than 5,000 km², predominantly made up of rural areas served by Hydro One Distribution. While some parts of the Entegrus system connect downstream of Hydro One's transmission system (i.e. Chatham. St. Thomas, Wallaceburg, Tilbury and Strathroy), most communities are embedded within Hydro One's distribution system.

Figure 3-4: Entegrus Service Area Map as of 2021



Entegrus communities are a mix of urbanized city areas and smaller town commercial and residential areas. Being a product of multiple past utility amalgamations, the service territory contains multiple types and configurations of legacy electrical equipment. Consolidating its equipment and configuration standards over time is a major dimension of Entegrus' System Renewal work.

As noted throughout this document, load growth has notably increased over the 2016-2020 Historical Period, with the most active growth segment across both predecessor utilities being the residential customers. This growth is discussed in detail in Section 1.4.6. Given the unprecedented growth in St. Thomas, particularly in 2020 and 2021, this DSP includes an additional breaker positions and associated supply feeders emanating from Hydro One's Edgeware transmission station. Entegrus is also investigating other solutions to address this loading capacity issue in St. Thomas, but a decision regarding these alternatives has yet to be made. See Section 4.2.1 and Section 4.2.2 for the discussion of the drivers underlying this planned investment.

As discussed in Section 2.2.3.4, Entegrus commenced planning for a major expansion to available connection capacity late in the Historical Period, owing to a connection application from a large agricultural cultivation operation. This expansion work was ultimately suspended in 2019 due to the customer withdrawing its application, and subsequently Entegrus received a second connection request from another large commercial greenhouse operator. This request was also later suspended in 2020. Given Entegrus' proximity to the Leamington area that has experienced such rapid and significant demand growth from commercial greenhouse proponents, Entegrus expects to receive more such inquiries in the future.

Entegrus' service area is characterized by a moderate humid continental climate. The climate is similar to that of the inland Mid-Atlantic 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 – and 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.

Agriculture, automotive and service industries are among the largest employers in the area.

3.2.2 Summary of System Configuration (5.3.2b)

A summary description of the system configuration, including length (km) of underground and overhead systems, number and length of circuits by voltage level, and number and capacity of transformer stations.

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

Entegrus operates overhead and underground line assets supported by 21 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, Entegrus is in the process of converting its system to a single standard 27.6 kV primary voltage, which will eliminate the need (and associated capital and OM&A expenditures) for substations. The oldest of the substations in service as of this writing was commissioned in 1955 (MP Sub 4 in Strathroy). The youngest – Thamesville DS – has been in service since 1984. A key facet of Entegrus' asset management strategy is to complete the area voltage conversion activities in a manner that enables it to retire the station equipment before it needs to be replaced.

The number of circuits Entegrus 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 3-2: Circuits by Voltage

Voltage Level	Active Circuit Count
27.6 kV	27
8.0 kV	8
4.16 kV	29
2.4 kV	5

Substation design varies significantly from simple rural padmount-style substations with no reclosers or advanced protection systems with a single feeder tap, to more sophisticated configurations featuring advanced SCADA capabilities and enabled with reclosers and an enclosing structure supplying multiple feeders. Entegrus serves load from 19 municipal stations, which contain a combined 21 power transformers. The average size of the station transformers is ~4.5MVA, with a minimum size of 2.0 MVA and a maximum size of 10MVA.

A significant change to Entegrus' service area since its 2016 DSP filing is the addition of about 34 km² of service area and assets previously served by the former STEI. While the system and individual assets operated by the former STEI are similar to Entegrus' in terms of their technology, ratings or configuration, there are some notable exceptions. One is approximately 17 circuit km of 2.4 kV delta-configured feeders, which now represent the lowest-voltage equipment on the Entegrus network.

Overall, the amalgamation with STEI increased Entegrus' total length of primary distribution lines by more than 20%, to the total of 980 km, of which 386 km (39%) are underground lines. In total Entegrus operates 71 feeders at voltages between 27.6 kV and 2.4 kV. Table 3-3 breaks down the length of circuits by voltage and type of service to further contextualize the system configuration.

Table 3-3: Length of Overhead and Underground Circuits

Type of Service	Voltages	Total Length (Circuit km)
Overhead	27.6 kV, 8.0 kV, 4.16 kV, 2.4 kV	594 km
Underground	27.6 kV, 8.0 kV, 4.16 kV, 2.4 kV	386 km

The bulk of Entegrus' underground infrastructure is concentrated in three of its largest communities, namely Chatham, St. Thomas, and Strathroy. Most customers in other Entegrus communities receive their power through overhead lines. Entegrus owns distribution system equipment that falls into the following major asset classes described in the Table below.

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Table 3-4: Entegrus Major Asset Class Counts

Major Category	Equipment Type	Unit Count
Substation Equipment	Power Transformers	21
	Circuit Breakers	20
	Switchgear	65
	Batteries	28
Overhead Infrastructure	Wood Poles	20,446
	Concrete Poles	63
	Steel Poles	928
	Overhead Conductor	594 km
	Overhead Transformers	3250
	Overhead Switches	736
Underground Infrastructure	Underground Cables	386 km
	Pad-Mounted Transformers	2300
	Submersible Transformers	194

Two distinct features of Entegrus' technical configuration that impact its costs and operational performance are the dispersed nature of its service territory and the location downstream of the upstream supplier's assets. The physical distance between Entegrus communities and the operations centres affects outage response times during trouble calls, and results in a portion of planned capital construction budgets being dedicated to driving to and from the sites. Similarly, by being embedded into the upstream supplier's distribution system, Loss of Supply events can impact Entegrus reliability performance.

As previously noted, Entegrus serves 17 communities in Southwestern Ontario, covering 132 km² of non-contiguous urban centres dispersed across a 5,000 km² geographic area. Between these urban centres, there are significant stretches of rural territory. This means that many Entegrus communities are served by long radial feeders. As a highly embedded distributor, maintaining distribution reliability can be a challenge with regard to upstream supply interruptions. Table 2-7 shows that reliability is influenced by loss of supply interruptions, by way of comparison of the "all outage cause" reliability metrics to the "loss of supply adjusted" reliability metrics. Successful collaboration with the upstream supplier has recently resulted in augmentation of supply reliability via the installation of automated switching. This has included working with the upstream supplier's protection and control personnel regarding the installation of circuits in Tilbury and Wallaceburg that have combined to help avoid nearly 18,000 Customer Hours Interrupted ("CHI") since being installed in 2017. Entegrus will continue to look for opportunities to work with the upstream supplier in this regard in communities where multiple supply point redundancies exist.

3.2.3 Results of Asset Condition Assessment (5.3.2c)

Information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled.

To perform an independent Asset Condition Assessment ("ACA") of its major distribution equipment, Entegrus retained third party engineering and analytics firm METSCO, who had conducted the utility's first formal ACA in support of the 2015 DSP. METSCO's full ACA report is available in Attachment C.

3.2.3.1 ACA 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 Entegrus. The assessments were based on the most recent inspection and testing data available, which was predominantly 2019 information.

Table 3-5: 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	Significant Deterioration of some components	Normal Maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
30-50	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
0-30	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

While different utilities often collect different types of asset data, the similarities in the Legacy Entegrus' and the former STEI's asset inspection policies enabled METSCO to develop consistent asset health scoring formulations. Entegrus recognizes, that similar *types* of information records collected by two separate utilities' field staff members from two distinct electrical systems, does not necessarily amount to consistent information. To this end, Entegrus is working with its operations personnel to standardize the inspection practices and reference points to ensure consistent collection across the service territory.

As noted in Section 2.1.6.2, Entegrus has significantly improved its asset data management practices. As a result of this focussed effort, METSCO had consistent access to more types of asset condition data, particularly with respect to station assets. Coupled with refinements to METSCO's asset health index formulations since the time of the last ACA, the availability of additional data resulted in material improvements in the Health Index formulations condition for certain asset classes, most notably, the populations of power transformers and circuit breakers, as described below.

The condition data records available for ACA analysis of Entegrus' line facilities are more limited than those for station assets, given the reliance on exception-based asset data collection for line inspections. Accordingly, METSCO focused on asset age as a significant data input when assessing condition of overhead and underground line and certain types of station assets.

As part of its ongoing asset management efforts, Entegrus has standardized its data collection processes across the service territory, which will result in a consistent data set being available going forward. The Entegrus GIS system provides not just an asset register, but also acts as a data source for many critical engineering and operational tools. Accordingly, Entegrus has an ongoing program to enhance the quality of the data stored in its GIS system. This program identifies information gaps, and where information quality may need to be enhanced, and also seeks to verify and improve the data through a mix of field inspection and referencing of historical paper documents. Via this program, it is expected continuous improvement in data completeness and quality will continue. The 2026 ACA should benefit from improvements in data availability.

The following sub-sections outline the ACA results for the major asset classes. See Attachment C which lays out the details of the ACA methodology and provides results for additional asset classes.

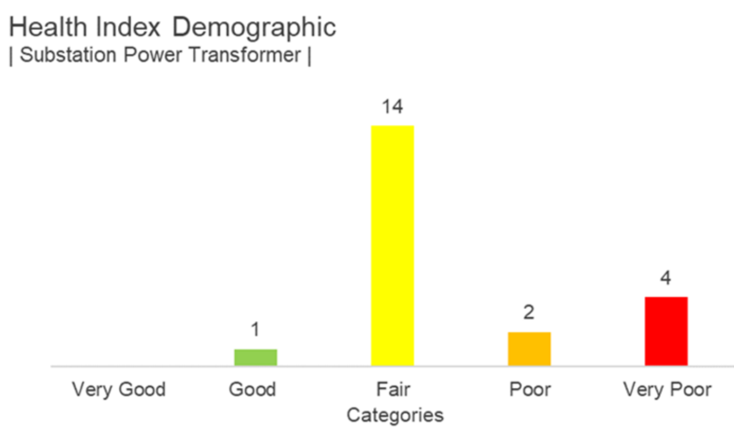
Overall, as detailed in the sections below, the ACA delineated 14 categories and subcategories of assets, covering the entire Entegrus installed asset base. The ACA showed that key asset classes were in "Very Poor" poor condition. Assets identified as "Very Poor" in the ACA have reached the end of their useful life and are at an elevated risk of failure. This includes the following asset category percentages identified as "Very Poor": Wooden Poles (25%), Submersible Transformers (22%), Overhead Transformers (20%), Substation Ground Grids (43%) and EPR / XLPE Cable (25%). While this is an indicator that Entegrus has successfully prolonged certain asset lives, it also indicates a need for significant reinvestment to maintain system integrity. In its report conclusion, METSCO recommended that "*maximum feasible resources be dedicated to active System Renewal work*" (see Attachment C, page 64).

3.2.3.2 Station Assets ACA Results

3.2.3.2.1 Power Transformers

Figure 3-5 below presents the results of METSCO's power transformer condition analysis.

Figure 3-5: Power Transformer ACA Results



The results were based on a combination of inspection and testing data points that included:

- Insulation Power Factor
- Dissolved Gas Analysis (DGA)
- Load History
- Insulation Moisture Content
- Oil Quality
- Overall Condition
- Bushing Condition
- Oil Leaks
- Oil Level
- Service Age

The results of the above analysis show changes relative to Entegrus' last ACA, which determined that all but five of the former Entegrus' transformers were in the Fair HI category, with the remaining ones being Good. The latest results differ with the transformers outside of the Fair category falling primarily in the Poor and Very Poor categories. The change in results is a function of three substations being decommissioned since the 2016 DSP (Chatham Sub 7, Strathroy Sub 2, and Blenheim West), and more comprehensive and consistent data availability for the remaining transformers as a result of improved asset data management processes.

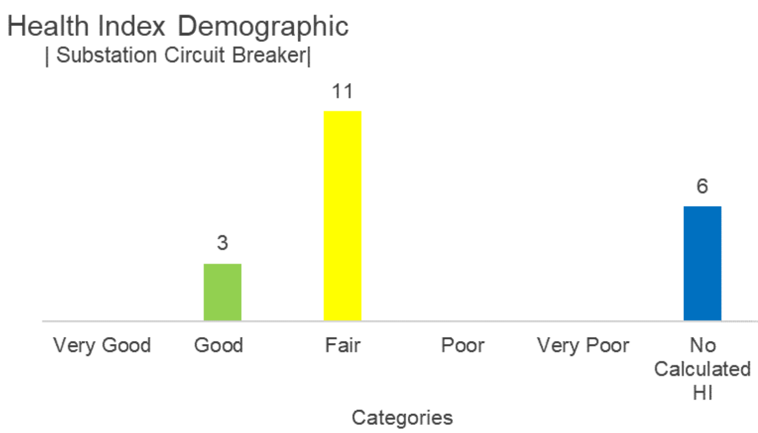
When it comes to the former STEI station transformers, the latest ACA results appear to be consistent with the last such assessment conducted in 2011 by Kinectrics. The results of the Kinectrics study suggested that all units in service at the time were either in Good or Very Good condition. Similar to the first iteration of the METSCO report, the last Kinectrics study relied on a smaller range of data inputs compared to what was used in the latest integrated METSCO ACA.

Based on the results of this assessment, Entegrus does not expect station transformers to be a significant investment driver over the Forecast Period. However, attention should be given to the six transformers in the Poor and Very Poor categories. Over the Forecast Period, preventative maintenance such as transformer drying work and other associated life extension activities for the Poor and Very Poor units can be carried out along with minor upkeep and expenditures associated with decommissioning of three to four additional substations.

3.2.3.2.2 Circuit Breakers

Figure 3-6 below displays the Circuit Breaker HI results across all types of equipment.

Figure 3-6: Circuit Breaker ACA Results



Depending on the type of a circuit breaker (e.g. Oil vs SF6 vs Air Blast) the following inspection and testing results were available to METSCO to conduct its Health Index analysis:

- Overall Condition
- Control and Operating Mechanisms
- Arc Chutes
- Coil Signature Tests
- Insulation Resistance Tests
- Contact Resistance Tests

As with power transformers, the circuit breaker HI results have materially changed since the last Entegrus ACA, where about half of all units in the scope of the study were assessed to be in Poor and Very Poor condition based on a lower amount of available data. None of the Entegrus – St. Thomas stations have circuit breakers. Consequently, the 2011 STEI ACA by Kinectrics did not include this asset class.

3.2.3.2.3 Switchgear

Figure 3-7 below showcases the ACA results for Entegrus' switchgear units.

Figure 3-7: Switchgear ACA Results

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. Neither of the predecessors' earlier ACA reports evaluated switchgear units as a separate asset class. Entegrus continues monitoring its station assets through monthly station inspections and will evaluate in more detail the condition of units in the highest age category.

3.2.3.3 Line Assets ACA Results

3.2.3.3.1 Overhead Equipment

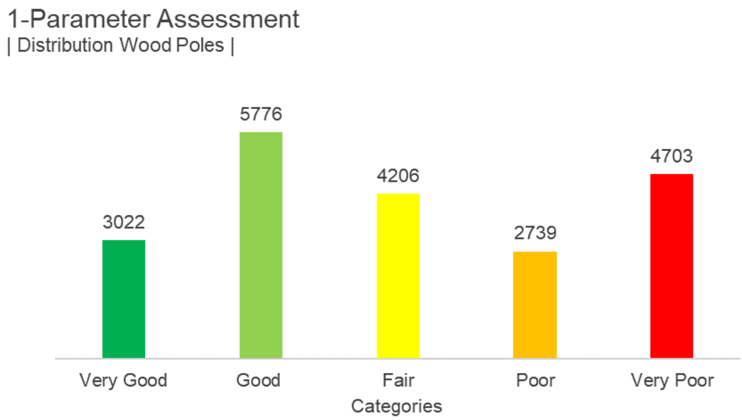
3.2.3.3.1.1 Distribution Poles

Entegrus' overhead system consists of approximately 21,000 poles, 95% of which are manufactured from wood, with the remainder made up of steel (4.4%) and concrete equipment units (0.2%).

Wood Poles

Although Entegrus took an innovative step by exploring the viability of predictive machine learning algorithms as an additional input into its wood pole health index, as discussed in Section 2.1.3.1, the results of this pilot initiative were not sufficiently robust to justify inclusion of the predicted drill test results into the health index. Since it relies on exception-based reporting for line assets, the only other data point Entegrus had available across the population was asset age. Accordingly, the results depicted Figure 3-8 in represent a one-parameter age-based assessment.

Figure 3-8: Wood Poles ACA Results



As the above analysis indicates, the condition of Entegrus' wood poles is a concern, as approximately 36% of the population have been assessed to be in the Poor and Very Poor HI cohorts. The results are substantially worse than the 2015 Entegrus study where only 14% of assets were assessed to be in the Poor and Very Poor categories, while a negligible percentage of poles represented the Poor and Very Poor cohorts in STEI's last ACA that took place in 2011. The changes are due to better data availability, and the passage of time during which a portion of both predecessor utilities' populations reached the age beyond the Fair HI threshold.

The utility will continue replacing its wood poles as a part of the proactive Voltage Conversion program, as well as reactively, based on recommendations from regular line patrols, the results of the drill test program in place today, and the emergency response work. Among the activities Entegrus plans to undertake over the Forecast Period is further exploration of predictive data analytics approaches in search of improving asset management economics.

3.2.3.3.1.2 Steel and Concrete Poles

The following Figures below showcase the ACA results for Entegrus' steel and concrete poles. Both distributions are based on age data only.

Figure 3-9: Steel Poles ACA Results

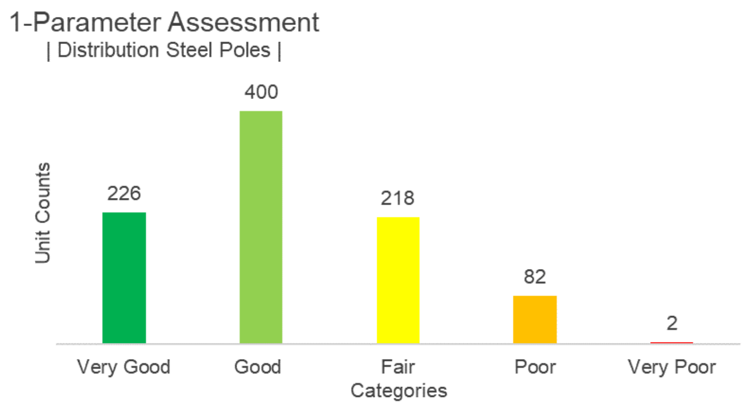
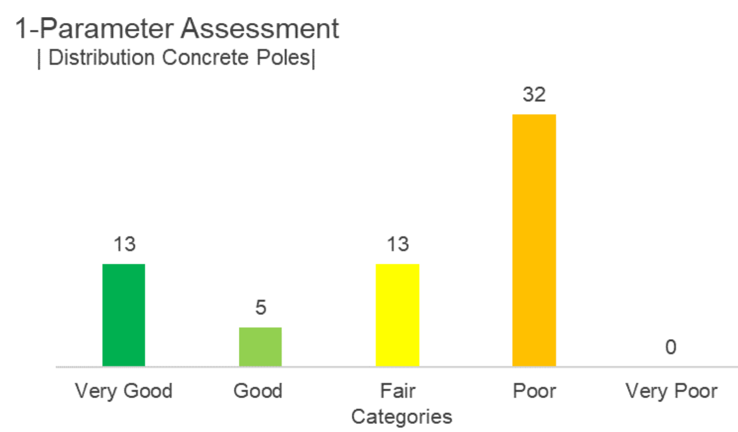


Figure 3-10: Concrete Poles ACA Results



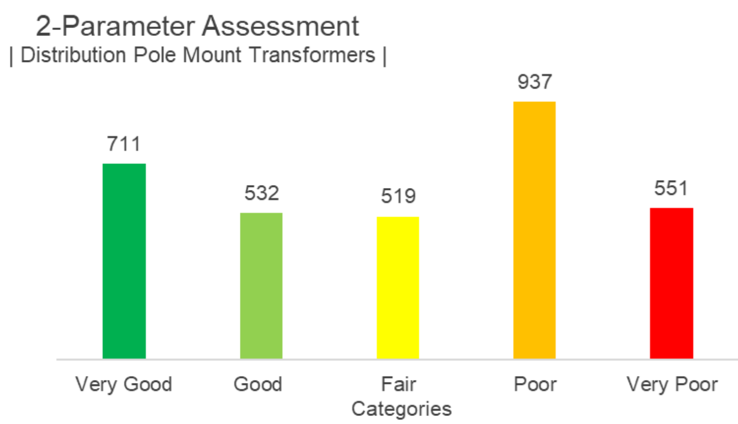
As a matter of grid modernization and standardization policy discussed in Section 2.1.3.3, Entegrus no longer installs new steel or concrete poles, unless specifically requested and paid for by a customer. Accordingly, all existing concrete and steel poles will be replaced by wood poles as they reach 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, and the decision to phase these assets out, Entegrus does not expect to dedicate any incremental resources to proactive condition data collection, beyond existing visual patrols and exception-based reporting.

3.2.3.3.1.3 Overhead Transformers and Conductor

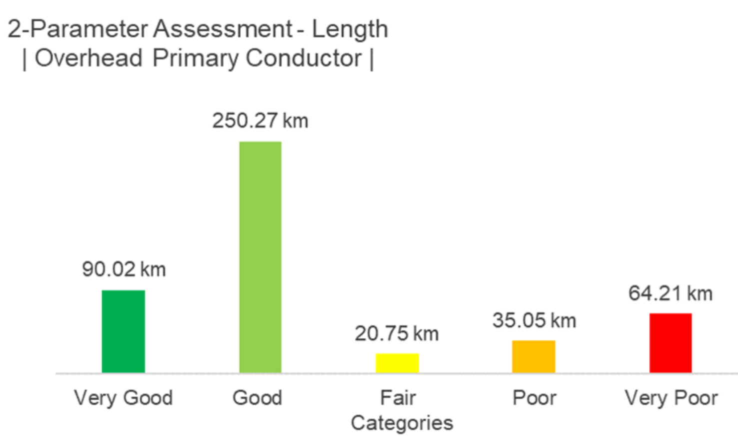
Figure 3-11 and Figure 3-12 the ACA results for overhead transformers and primary line conductor, respectively.

Figure 3-11: Pole Mount Transformers ACA Results



Transformer results are based on a two-parameter assessment of age and load history. METSCO's 2015 ACA study for Entegrus grouped all distribution transformers together, making comparisons with the last version impractical. The 2011 STEI ACA did not consider overhead transformers.

Figure 3-12: Overhead Primary Conductor ACA Results

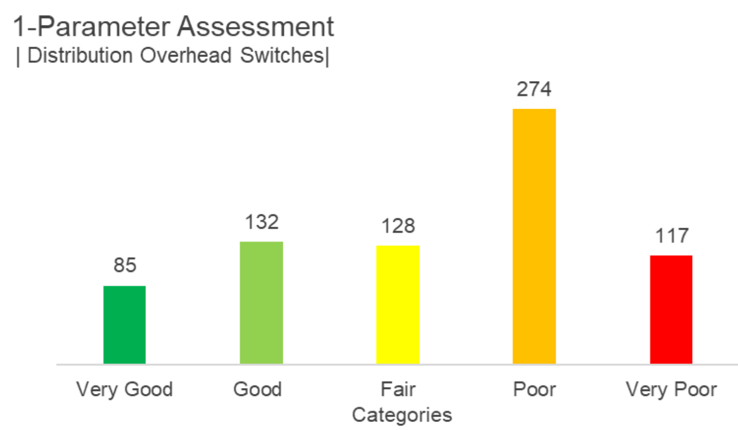


The ACA results for the primary conductors also consist of a two-parameter assessment – namely age, and a gateway parameter known as the Small Conductor Risk, which automatically de-rates certain types of outdated small-diameter copper conductor that has been largely phased out across North America. Entegrus plans to continue proactively replacing its overhead transformers, conductor and other associated pole top equipment 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.

3.2.3.3.1.4 Overhead Switches

Figure 3-13 below showcases the results of the age-based assessment for Entegrus' overhead switches.

Figure 3-13: Overhead Switches ACA Results



As with other types of overhead assets, the health of Entegrus' population of switches (as represented by the age data) suggests the rationale for substantial follow-up inspection work at a minimum in relation to the units assessed to be in Poor and Very Poor condition.

3.2.3.3.2 Underground Equipment

3.2.3.3.2.1 Pad-Mounted and Submersible Transformers

Figure 3-14 and Figure 3-15 display the ACA results for the population of Entegrus' 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 3-14: Pad Mount Transformer ACA Results

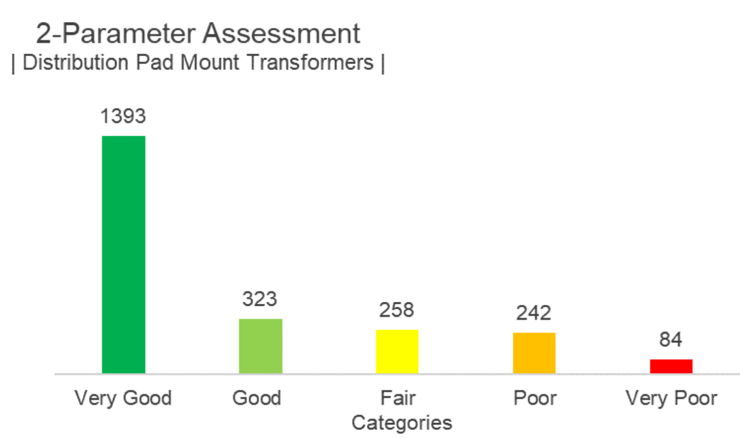
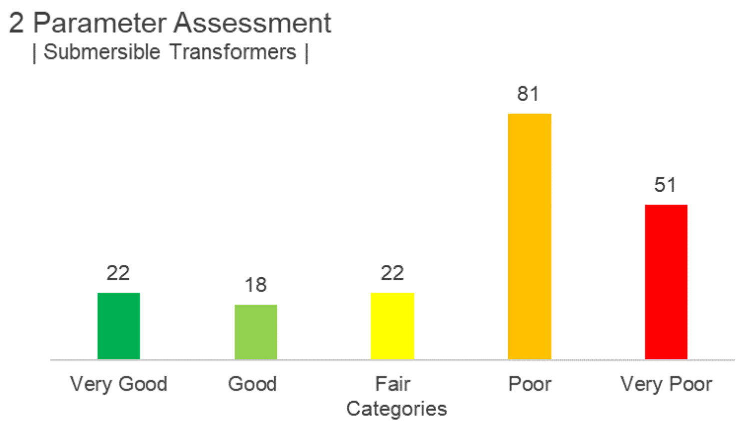


Figure 3-15: Submersible Transformer ACA Results



As with the overhead plant, Entegrus' 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.

A near miss in 2018 involving a submersible transformer resulted in Entegrus accelerating the phasing out of submersible transformers, a project first identified in the 2016 DSP. Beyond inspection in 2018 to determine which units required immediate replacement for safety reasons, Entegrus will continue to perform periodic inspections based on our ESA requirements while prioritizing conversion projects on the remaining units. The incremental System Renewal investment over the 2021-2025 Forecast Period will assist in accelerating this process.

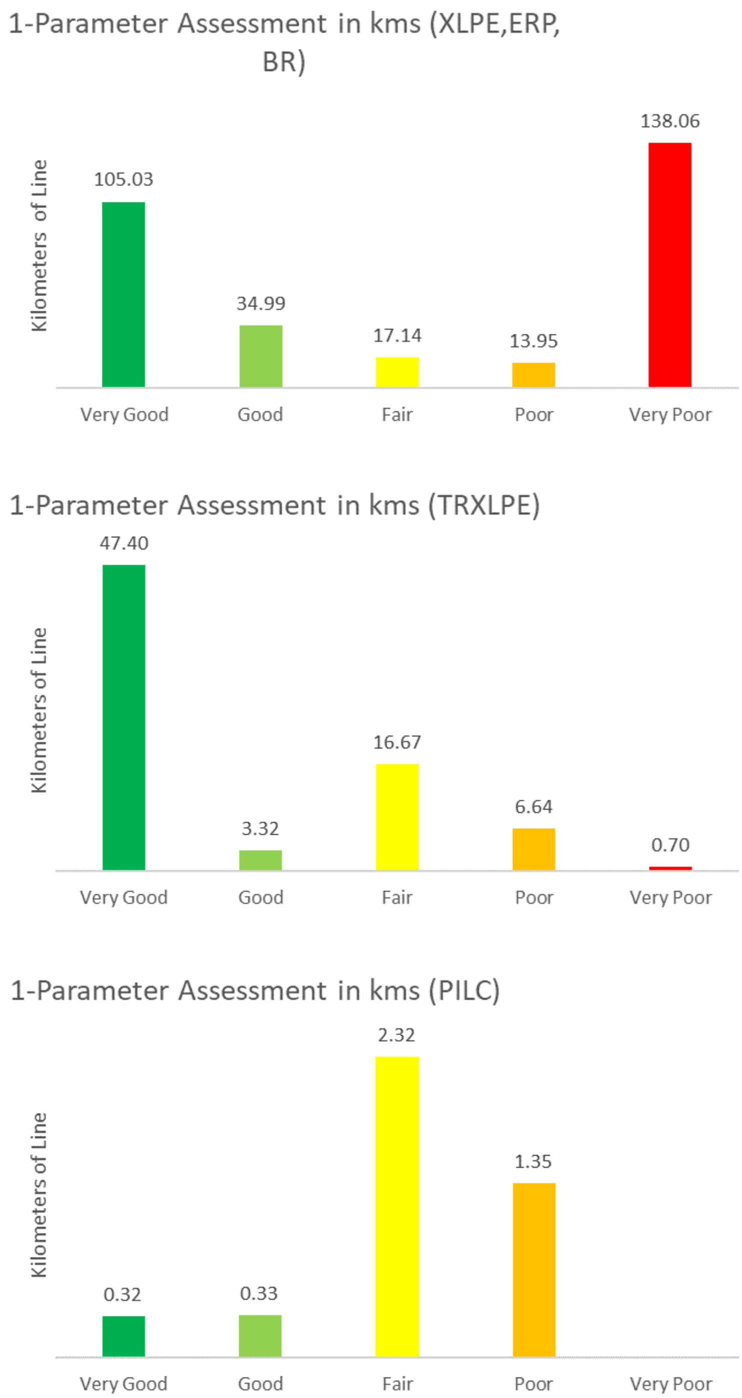
Approximately 10% of pad-mounted transformers are in the Poor and Very Poor condition, warranting follow-up and replacement in the course of ongoing renewal activities consistent with the Lifecycle Management policies discussed in Section 3.3

Nearly 60% of the remaining submersible transformers appear to be in Poor and Very Poor condition. Entegrus currently has 194 submersible transformers and is committed to phasing this particular technology out from its system, given the added operating costs and safety risks associated with working in and around the underground vaults that house these units. The relatively small current number of the overall units reflects the utility's past efforts to proactively reduce the presence of this asset class across its service territory.

3.2.3.3.2.2 Underground Primary Cables

Entegrus deploys three main types of primary underground cables across its service territory, namely Tree-Retardant Crosslinked Polyethylene ("TRXLPE"), Paper-Insulated Lead-Covered ("PILC"), and Ethylene Propylene Rubber-Insulated ("EPR"). Figure 3-16 provides the results of an age-based assessment of these assets.

Figure 3-16: Underground Primary Cable ACA Results



The primary underground cables in use at Entegrus differ in their mode of installation across direct-buried, rubber duct-encased and concrete-encased cables. Consistent with many of its Ontario peers, Entegrus inherited an incomplete set of records as to the mode of deployment of cables from its various predecessors. As the above charts indicate, the XLPE cables are in the oldest cohort and represent the most likely candidates for renewal in the near to medium term.

Also, of note is the aging cohort of the PILC cables. While these assets are still well within the bounds of their expected useful life, the demographic concentration of the population and the added cost and complexity of the associated repairs may present an issue further in the future.

Finally, approximately 45 circuit km of its underground cables are deployed on 2.4/4.16 kV legacy low-voltage circuits, all of which are subject to future conversion to the new 27.6 kV standard. While Entegrus plans to convert all its low-voltage feeders to the new standard over time, in recent years its approach to the underground conversion largely entailed reactive replacement only. This is primarily due to the cost magnitude difference between the overhead and underground conversion, and Entegrus' preference to maximize the impact of its available System Renewal spend. Notwithstanding this strategy, Entegrus understands the value of enhancing its understanding of the health of its aging underground cables. To this end, Entegrus will explore its options with targeted cable testing over the Forecast Period.

Please see Attachment C for METSCO's complete ACA report, which includes discussion of several additional asset classes not covered in the above summary.

3.2.4 System Utilization (5.3.2d)

An assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets.

Where cited as a driver of a material investment(s) included in the capital expenditure plan, distributors must provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.

3.2.4.1 Feeder and Substation Capacity

Entegrus regularly monitors the loading levels of its feeders and distribution stations to ensure that available system capacity continues to match the current requirements and near-term load growth projections. As a means of risk management for the station assets with the highest loading levels or other known risk drivers, the utility deploys additional Protection and Control ("P&C") devices at these locations. As

Table 3-6 showcases, the utilization of Entegrus' substations do not point at any emerging capacity constraints. This is consistent with Entegrus' strategy to phase out its substation infrastructure as it gradually converts the low-voltage feeders to a standard 27.6 kV voltage. Accordingly, while it continues monitoring the station capacity and responding to any emerging issues, the utility does not anticipate making any major substation assets investments in the future.

Table 3-6: Station Loading and Capacity Utilization

TS/DS Name & Town	Capacity (MVA)	2016 Peak Load (MVA)	2017 Peak Load (MVA)	2018 Peak Load (MVA)	2019 Peak Load (MVA)	Avg % Utilization
Ridgetown						
RICT1	3.0	2.83	2.38	1.92	2.95	84%
RITT1	3.0	1.56	1.03	0.79	0.88	35%
Blenheim						
BLET1	5.0	1.89	2.16	1.63	2.17	39%
Wheatley						
WHT1	2.0	1.73	1.56	1.73	1.58	82%
Chatham						
SUB1T1/T2	20.0	3.50	1.87	3.00	3.85	15%
SUB3T1	7.5	10.78	10.21	3.68	3.50	94%
SUB4T1/T2	5.0	2.07	1.90	1.07	0.94	30%
SUB6T1	6.0	1.68	1.56	1.78	1.55	27%
Strathroy						
MPSUB1	5.0	2.94	2.64	3.23	2.62	57%
MPSUB3	3.0	1.20	1.56	1.32	1.15	44%
MPSUB4	3.8	2.51	2.05	2.50	1.87	59%
MPSUB5	5.0	2.79	2.29	0.97	0.82	34%
Thamesville						
DSSub	2.5	1.69	1.43	1.73	1.51	64%
St. Thomas						
SUB9	3.0	0.67	0.55	0.20	0.20	13%
SUB10	3.0	1.11	1.16	0.78	0.67	31%
SUB11	3.0	1.28	1.41	1.42	1.22	44%
SUB13	3.0	0.20	0.65	0.05	0.27	10%
SUB14	3.0	0.79	0.62	0.62	0.58	22%
SUB15	3.0	0.56	0.10	0.00	0.00	6%

Entegrus also actively monitors the loading levels on its individual feeders. In the recent past, feeder capacity constraints typically arose in relation to the legacy low-voltage distribution network that are subject to an active multi-year voltage conversion program. Given its voltage conversion strategy, Entegrus seeks to forgo any expenditures to further expand or reinforce the low voltage feeders to accommodate new load. Whenever technically and economically feasible, the utility avoids connecting any new services to the low-voltage feeders. To this end, every connection request with anticipated demand over 200 kW undergoes an assessment from the Planning department as a part of the regular connection application process. In some cases, the recommendations from the Planning department result in new customer loads being connected to feeders beyond the immediately adjacent low-voltage infrastructure. In cases where capacity constraints may arise on the 27.6 kV feeders, Entegrus resolves them by way of load transfers or other actions that may be appropriate.

3.2.4.2 Upstream Capacity

By virtue of its location that straddles the boundaries of four neighbouring Ontario Regional Planning Zones, Entegrus is also constantly engaged in activities that explore its system's impact on the upstream Hydro One assets. As discussed in Section 2.2.3 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 Entegrus (Strathroy TS and Kent TS T3). In both cases, Entegrus and the upstream supplier collaborated on detailed technical studies to confirm the results of higher-level analysis conducted through Regional Planning.

To enable its participation in the Regional Planning activities and ensure effective monitoring of its own downstream capacity needs, Entegrus maintains and periodically updates a station-level load forecasting model. The model relies on econometric analysis of relationships between customer load and the economic and environmental factors that influence load growth over time. In addition to the quantitative forecasting results, Entegrus also considers other sources of planning information, obtained through consultation efforts described in Section 2.2.2, 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, Entegrus considers the less costly opportunities that may be available through load transfers or other modifications to the existing system, such as changes to the protection schemes.

By integrating the econometric forecasts, technical engineering analysis and more qualitative insights (such as anticipated zoning changes in the municipalities it serves) Entegrus can assess its upcoming capacity needs in a holistic manner. Section 4.1 provides a practical example of this holistic approach by discussing the expected evolution of Entegrus' system over the Forecast Period and the ensuring System Service investments included in the Plan.

3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment.

Entegrus 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 3.1.2. While Section 3.1.2 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.

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

3.3.1.1 Implications of Future System Vision on Asset Lifecycle Management Practices

A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

- A description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes, tools) system renewal program spending is optimized

- A description of routine system O&M activities carried out to sustain required distribution system performance to the end of the subject asset's service life. Including but not limited to preventative inspection and maintenance policies, practices and programs (can include references to the Distribution System Code (DSC)).

- A description of how asset replacements are prioritized and scheduled to align with budget envelopes and how the impact of system renewal investments on routine system O&M is assessed

- A description of maintenance planning criteria and assumptions

3.3.1.1.1 Replacement vs. Refurbishment

As it proceeds with its Voltage Conversion program, Entegrus is moving towards a longer-term vision of a singe-voltage primary distribution system that does not feature any substation assets. To attain this vision in the optimally efficient manner, Entegrus must time the eventual phase-out of its distribution substations before any major station renewal investments would be required. In practice, this means that conversion of the low-voltage feeders emanating from 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 inspection and testing activities for the substation assets that are more comprehensive than those for the line infrastructure.

Moreover, the vision of its long-term system configuration and the steps required to attain it provide relatively few practical opportunities for near/medium-term intervention options like asset refurbishment. This is largely because the majority of Entegrus' 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 generally Entegrus' preference to avoid making any incremental renewal investments to the low-voltage feeders aside from smaller reactive fixes driven by individual asset failures, poor 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, Entegrus generally expects to phase out its substations before their major components reach end of life. Entegrus acknowledges that substation asset refurbishments will be required in some cases, particularly if the rate of station asset deterioration deviates from its current expectations. However, at present, Entegrus plans to phase out its low-voltage feeders and the associated substations before this option may warrant significant consideration.

It is also worth noting that during the Historical Period, Entegrus conducted a small-scale trial of underground cable refurbishment by way of injection, which produced mixed results at a significant cost. Given the high costs and mixed results of its own pilot, and the anecdotal evidence of many Canadian utilities putting this practice on hold pending further efficacy testing, Entegrus chose not to integrate this practice into its regular maintenance work. Beyond the concerns with efficacy, the decision to forgo further cable injection work was also a function of the configuration of Entegrus' underground assets, which are usually looped and located on lateral portions of feeders. Given this predominant configuration, cable injection has limited value proposition as the impact of underground outages is relatively minor, while the effort that would be involved in conducting the requisite testing and injection activities would be significant.

Based on the above considerations, the scope of refurbishment works practically applicable to Entegrus' electrical assets entail the following:

- Revenue meter re-sealing (where permitted by Measurement Canada standards);
- Repurposing of distribution transformers that require upsizing early in their useful lives (due to conversion work or changes in customer demand levels); and
- Discrete opportunities for life extension of unique / high-value assets, such as the SCADA-controlled switches discussed in Section 2.1.3.1.

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

3.3.1.1.2 Proactive vs. Reactive Asset Replacement

Entegrus believes that it is neither practical nor economically efficient to prevent every asset failure that happens in the field by way of 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 Entegrus assumes during risk-based power system planning analysis (subject to the important exceptions noted below). Doing so 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, Entegrus 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 a Run to Failure approach is also consistent with Entegrus' 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, Entegrus plans to make them redundant through the ongoing conversion of low-voltage feeders that emanate from them. While Entegrus 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, Entegrus invests significant resources into station equipment condition monitoring (e.g. Dissolved Gas Analysis) and life extension activities (breaker timing tests, transformer drying, etc.). As such, while Entegrus plans to run these assets to failure and not replace them – it is a key priority (and O&M driver) for Entegrus 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, Entegrus 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 targets geographically and electrically adjacent areas and involves application of new technical standards (rather than like-for-like renewal), proactive replacement approach enables Entegrus 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, Entegrus also utilizes proactive replacement when dealing with higher-criticality assets, such as larger distribution transformers, three-phase overhead line assets, or DA infrastructure. Similarly, Entegrus is proactively removing the remaining submersible transformer units from its underground system, given the higher operating costs and additional safety risks involving work in confined spaces.

3.3.1.1.3 Equipment Ratings and Overhead vs. Underground Asset Renewal

When it comes to equipment rating, type of service and core technology, Entegrus typically replaces its assets on a like-for-like basis. Notable exceptions include activities such as the voltage conversion work, customer-driven connection facility upgrades, or removal of outdated equipment like porcelain insulators or poletrans transformers.

Entegrus 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, Entegrus' 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, Entegrus 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.

3.3.1.2 Regular Asset Inspection and Maintenance Activities

3.3.1.2.1 Substation Inspection and Testing

Entegrus 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 occurs on a bimonthly basis using a shallow drain test. To the extent possible, Entegrus seeks to mitigate any identified battery-related deficiencies on the spot.

To ensure that its major station assets remain in an adequate operating condition, Entegrus 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, include the following:

Substation Transformers:

- Oil Dissolved Gas Analysis ("DGA") Testing;
- Oil Quality and Oil Level Testing;
- Insulation Power Factor Testing;
- Oil Leaks Identification;
- Transformer Bushing Condition Inspection;
- Overall Unit Condition Inspection.

Circuit Breakers:

- Contact Resistance Tests;
- Insulation Resistance Tests;
- Control and Operating Mechanism Testing;
- Overall Breaker Condition Inspection;
- Coil Signature and Arc Chutes Tests (as applicable).

Entegrus uses the results of the above inspection and testing activities to compile asset Health Indices 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 3.2.3.2 for the results of the latest station asset condition assessment.

3.3.1.2.2 Line Infrastructure Inspection and Maintenance

Entegrus 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, Entegrus 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 Entegrus. With the enhancements to asset data reporting and processing discussed in Section 1.4.7.2, the exception reporting strategy gives Entegrus planners a quick and efficient way to obtain new information and incorporate it into the near-term field work plans.

3.3.1.2.2.1 Overhead Assets

The current overhead line patrol approach entails visual inspection of poles, conductor, 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.

As discussed elsewhere in this Plan, Entegrus does not currently have a fully established (cyclical or risk-based) pole drill testing program. Instead, the utility subjects a small randomly generated subset of wood poles to drill testing each year, which enables it to use statistical sampling techniques discussed above to draw direction inferences about the health of the overall population. Entegrus generates an additional annual subset of pole testing data by way of the Engineering Department's work to install or modify third-party pole attachments. Entegrus also conducts drill tests in response to marginal visual inspections or in the course of planned work where asset ages and condition lead to a challenging "keep or replace" decision where pole test results act as a potential tiebreaker. Entegrus plans to continue refining its approach to data science-driven health assessments over the Forecast Period.

Vegetation contacts can be a cause of sustained interruptions experienced by Entegrus' customers. The utility employs proactive tree trimming activities on a four-year cycle within its Chatham-Kent and St. Thomas operating areas, while the feeders in the Middlesex area (Strathroy, Mt Brydges, Parkhill) undergo trimming every three years. Entegrus 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.

3.3.1.2.2.2 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 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.

Entegrus 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 continuing active phaseout of its remaining 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, Entegrus prioritizes the projects that include submersible transformer replacement relative to other comparable projects under consideration.

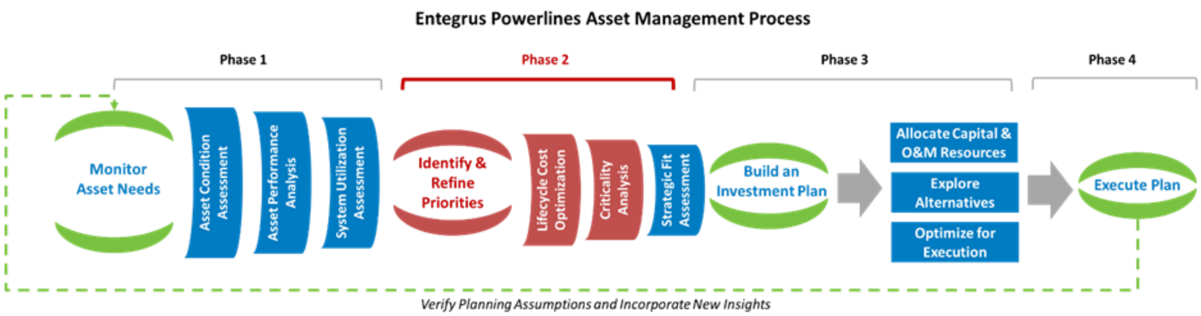
3.3.2 Electrical Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used, types of information inputs and outputs, and how conclusions of risk analyses are used to select and prioritize capital expenditures.

Consistent with its inaugural DSP, Entegrus continues to rely on and gradually refine its approach to risk-based asset management analytics. Risk-based analysis is a tool that helps Entegrus define the optimal mix, volumes, locations and relative sequencing of its System Renewal investments.

While Section 3.1.2 of this Plan (parts 2.1-2.3) provides an overview of the fundamental principles of risk-based asset intervention planning, this section discusses the nature of specific inputs, methodology, and outputs of the analysis Entegrus conducted in preparation of the 2021-2025 DSP. Figure 3-17 below highlights in red the parts of Entegrus' AM process (originally introduced in Figure 3-1) where risk-based planning occurs.

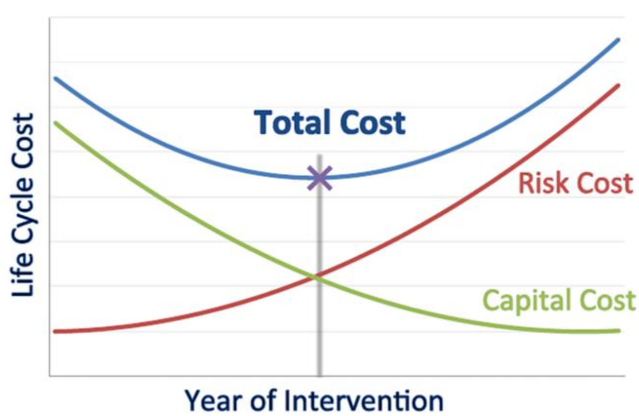
Figure 3-17: Risk-Based Planning in the Context of the Asset Management Process



3.3.2.1 Asset Management Analysis Fundamentals

As described in Section 3.1.2, the fundamental principle underlying the Entegrus approach to AM analytics is minimization of asset lifecycle costs – that is the total lifetime direct spend and indirect costs arising from operating a given asset from its installation to decommissioning. Lifecycle cost minimization involves scheduling asset intervention (replacement or refurbishment) as closely as possible to the point in an asset's life, where its annualized Capital Costs (which decline over time) equal its annualized Risk Costs (which increase over time) as shown in Figure 3-18.

Figure 3-18: Risk-Based Asset Intervention Analysis



A key notion supporting this methodology is the concept of Risk Costs, which holds that while utilities spend money to manage their assets every day, they should also seek to prevent events (such as failures) the cost of which exceeds the cost of preventing them (e.g. such as by replacing assets before they fail). In conducting the cost-benefit analysis of preventing future failures through replacement, the cost of asset replacement at a given time is treated as a Cost (or cash outflow), while the cost of potential failure that replacement avoids is treated as a Benefit (or cash inflow). Recognizing that future asset failure (and its ensuing cost) is not certain, comparing the potential cost of failure with the certain cost of replacement requires adjusting the cost of failure (expressed in dollars) by the probability of that failure occurring (expressed as a percentage). The adjustment of an estimated cost impact of failure by the estimated probability of failure yields the Risk Cost estimates:

$$Risk\ Cost\ of\ an\ Event\ (\$) = Probability\ of\ an\ Event\ (\%) \times Impact\ of\ an\ Event\ (\$)$$

To account for the opportunity cost of capital and the fact that both costs and failure probability change over time, the cost-benefit analysis involves an adjustment to account for the time value of money, using the Weighted Average Cost of Capital ("WACC") embedded in a utility's rates. To account for the value already derived from operating the existing asset, the analysis annualizes its lifetime capital costs and incorporates only the value remaining at the time of a hypothetical intervention.

In the end, the fundamental idea behind this risk-based asset intervention analysis entails a Net Present Value ("NPV") evaluation of the costs of continued operation of an asset, and the benefits of replacing that asset to avoid the risk-adjusted costs consequences of its failure. To further substantiate the analytical process logistics, the following passages describe the set-up, input sourcing and application of the analysis.

3.3.2.1.1 Asset Status Quo

Working with Entegrus asset planners, METSCO began its analysis by establishing the system's Asset Status Quo. The first step entails a detailed System Connectivity Analysis, which explores and confirms the hierarchies, redundancies, tie-points across individual Protective Regions and individual electrical assets (using unique asset IDs). These relationships are established by analyzing the data in Entegrus' CYME software used by planners and system operators to conduct load flow studies. The connectivity relationships that reflect the distributor's actual system configuration are a key factor in establishing the criticality of a specific asset relative to other system components. The higher the criticality of an asset, the higher the impact of its failure will be on the system, other things being equal.

A related software set-up step involved establishing geographical relationships (based on GIS coordinates) between energized assets (e.g. distribution transformers and cables / conductors) and core non-energized assets supporting them – most notably distribution poles. Having established and verified the electrical connectivity and geographic relationships between specific Asset IDs, these were then matched to demographic and health data for individual assets. In the specific case of Entegrus, METSCO sourced the age and raw condition asset parameter data from Entegrus' GIS system that also serves as its Asset Registry. METSCO then translated the raw inputs into asset Health Indices ("HI"), using the approach discussed in Section 0 and Attachment C. The final step in this portion of the analysis set-up involved matching the age and condition results with the connectivity database using unique Asset IDs.

Supplementing the age, health and connectivity work are the inputs related to asset replacement costs – including the details on labour, materials, equipment, vehicle use charges, warehousing overhead, engineering/design, and other cost components available to a utility. Other notable cost factors include the adders for emergency / overtime asset replacement and outage restoration work, equipment rentals, or the pricing of contractor labour. To track this information, Entegrus relied on its recently enhanced asset assembly unit cost database introduced in Section 2.1.6.4. The unit cost information served as a key input for several components of the risk-based analysis, namely:

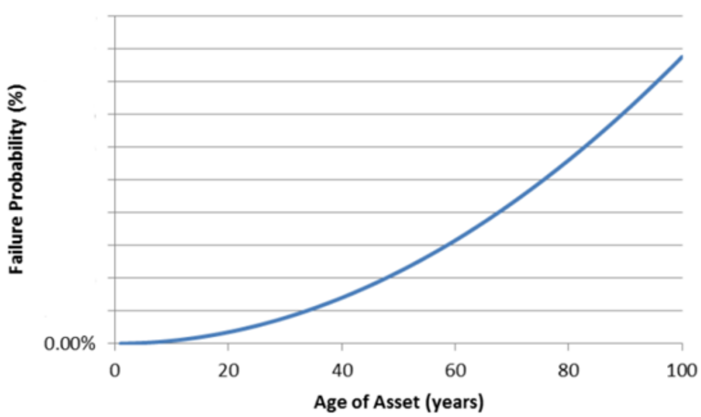
- Annualized Capital Cost of existing assets;
- Risks Cost component driven by emergency replacement cost of assets that fail in service; and
- A variety of assessment restrictions (filters) that can be customized prior to conducting the risk analysis (e.g. available labour hours by skillset, vehicle availability, regional spend, etc.).

Based on the level of detail available in Entegrus' asset assembly database, the inputs were sufficiently granular to differentiate between materials and labour costs required for multiple pole heights, transformer and conductor ratings, and various circuit configurations. While this enabled the ensuing analysis to be relatively granular, it is nevertheless important to note that the input costs reflect the planning-level estimation rather than site-specific design-level estimates that take place during the final stages of project preparation, or the "Optimize for Execution" part of Entegrus' AM Process denoted on Figure 3-18.

3.3.2.1.2 Asset Failure Probability

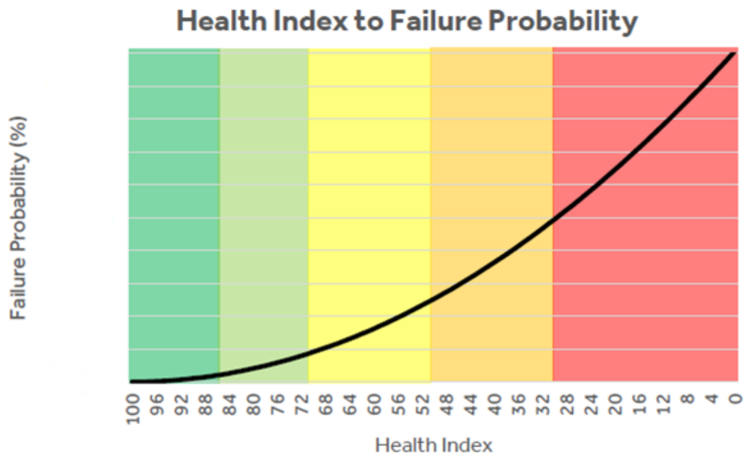
The next step in the configuration of the AM process involves inputting the assumptions related to the probability of failure of specific asset classes based on their age. Estimates of individual assets' probability of failure are determined using industry Failure Probability Curve data for each asset class. Failure Curves capture equipment's average probability of failure at a given age or condition. The probability curve stem from industry research on equipment's median life expectancy, augmented where possible by field data on failure and replacement records available from METSCO's past engagements. Figure 3-19 showcases a sample failure probability curve for power transformers.

Figure 3-19: Power Transformer Age-Based Failure Probability Curve



In cases where sufficient condition-based inspection or testing data is available for a given asset class, asset condition data is incorporated as well. This is done by translating an asset's "Calendar Age" (i.e. age since installation) into its "Effective Age" – age in service adjusted to reflect its current condition (as represented by its numerical Health Index ("HI") Score).

Figure 3-20: Incorporating Condition into Age-Based Failure Probability



Since numerical HI values estimate the percentage of an asset's remaining useful life, their results are translatable into an adjustment factor that augment's a specific asset's actual age to capture the higher degradation rate that may be indicated by the condition analysis. Figure 3-20 showcases an example of a condition-based failure curve for power transformers.

As a result, a given asset's failure probability can be effectively decoupled from its calendar age, by "pushing" the asset along the age-based failure probability curve depending on the results of its condition assessment. Doing so has the benefit of differentiating the failure probability of two assets that are otherwise similar in terms of age and design. From its engagements with METSCO, Entegrus understands that failure probability calculation is a field of asset management science that is still rapidly evolving, meaning that assumptions underlying the current failure models are subject to further refinements. Notwithstanding this reality, Entegrus sees the core benefit of the asset failure probability methodology at its current stage of development in that it enables the utility to apply an objective, consistent and data-driven approach to prioritize among large populations of otherwise similar equipment and identify smaller subsets that warrant further analysis.

3.3.2.1.3 Asset Failure Impact

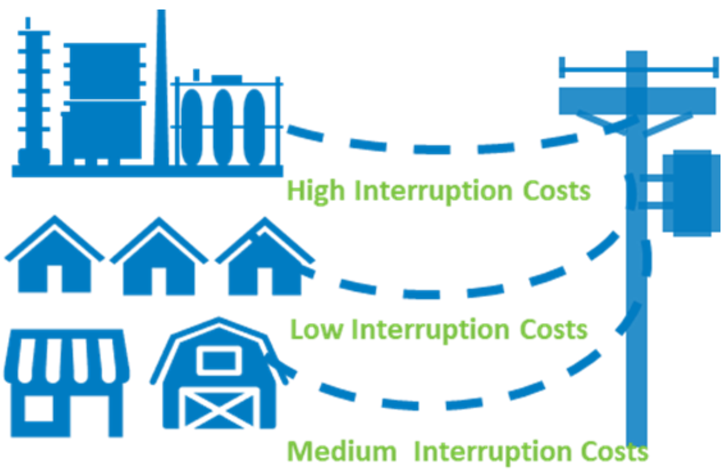
The remaining input step in the process flow is to configure the estimates of the impact of asset failure that planning analysis seeks to avoid. There are two fundamental components to asset impact costs, namely *Direct* and *Indirect* costs. Direct costs are those that the utility itself incurs, including labour, materials and equipment involved in addressing a failed asset. The magnitude of direct costs of asset failure depends on the type of equipment, and the "way" in which an asset fails, referred to as the Failure Mode.

Most assets fail when the internal or external degradation processes or other type of damage affects their structural integrity or mechanical functionality in a way that prevents them from performing their core function. While this "normal" type of failure may cause a power outage, it has relatively few other direct cost implications than the remediation of an outage and replacement of failed equipment. This is in direct contrast to "catastrophic" failures – which are less common and involve events like transformer fires and explosions, or physical collapse of overhead and underground civil infrastructure. In addition to outage remediation and equipment replacement costs, catastrophic failures may bring about other significant costs, such as collateral damage to nearby infrastructure, costs of safety incidents to utility personnel or the public, and/or environmental damage like transformer oil spills.

To account for these eventualities, inputs include assumptions of the actuarial cost of environmental and safety incidents that accompany catastrophic failure. Taken together, the probabilities of normal and catastrophic failures sum up to equal total (age- or condition-based) failure probability in each year of an asset's lifecycle.

Indirect failure costs represent the cost consequences of outages incurred by the utility' end-use customers. As Figure 3-21 suggests these Customer Interruption Costs ("CICs") typically vary by customer class.

Figure 3-21: Relative CIC Magnitude by Customer Class



Industrial consumers, who rely on continued supply of electricity to power their manufacturing, processing, or extraction equipment, typically sustain the greatest economic impact due to power outages, or in some cases even power quality fluctuations where sensitive equipment is present. Where backup power is unavailable, power outages affecting industrial customers can lead to delayed shipments, increases in shift labour costs, damage to equipment, spoilage of inventory, or even safety incidents. Commercial customers such as office towers, box stores or farms are typically affected to a lesser degree than industrial customers, yet still often sustain material economic impact due to interruptions to productive activities and damaged inventory, among others. On average, residential customers typically sustain the lowest economic impact from power outages compared to other customer classes. However, individual customers, such as those running small businesses from home, dependent on life-supporting medical equipment, or reliant on electricity for heat, may be affected to a significant degree.

Customer Interruption Costs (“CIC”) consist of two components: the cost of an outage’s initial occurrence, and the unitized cost per hour of outage duration. In general, longer outages result in larger costs. However, a common assumption used in the CIC analysis is that hourly costs of particularly long interruptions become lower after a certain threshold (e.g. 4-5 hours), as customers take own steps to minimize the impact of themselves (through temporarily relocating themselves or perishable inventory, securing means of temporary supply, etc.).

To estimate the CIC costs applicable to Entegrus’ service territory, METSCO relied on the U.S. Department of Energy’s Interruption Cost Estimation (“ICE”) Calculator, designed though collaboration between the Lawrence Berkeley National Laboratory and Nexant, and supported by the United States Department of Energy.[10] While the ICE calculator tool is based on the United States data, METSCO calibrated the CIC values by using the inputs for U.S. states with comparable economic and geographic characteristics. Prior to implementing the CIC framework, METSCO also discussed the draft CIC values with Entegrus staff to ensure alignment before conducting further analysis.

Finally, the CIC assumptions establish the impact of potential outages across individual assets and protective regions, depending on the specific mix of customers each of them supports, and their electrical location vis-à-vis other assets that may either depend on their functionality, or offer a redundant supply path.

3.3.2.1.4 Running the Analysis

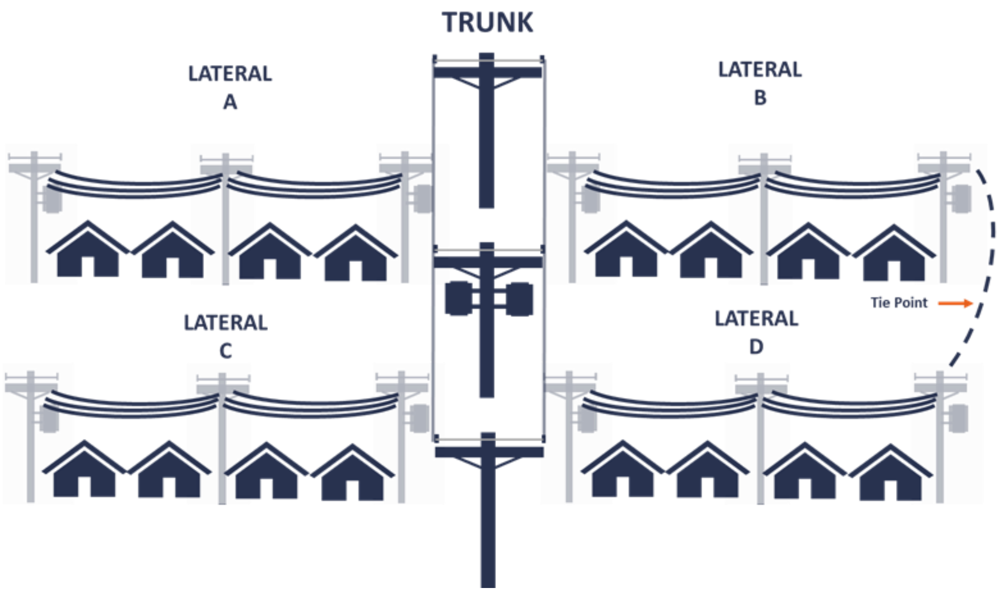
Using the inputs of failure probability, failure impact, asset maintenance and replacement costs, along with the asset hierarchies from the connectivity model to the above-described approach searches the system for individual assets or protective regions that represent the highest mitigatable failure risk.

As an illustrative example, a failure anywhere along the trunk feeder depicted in the Figure 3-22 would represent a higher risk than a failure on any of the four Laterals, assuming the ages and condition were comparable. However, assuming the same ages, conditions, and CICs, a failure along either Laterals A or C would represent a higher risk than a failure along either of the Laterals B and D. This is because of the feeder tie point between the latter pair that could provide a redundant supply path, and thus reduce the impact of equipment failure. However, assuming that assets on Lateral B were of substantially poorer health or age than those on its neighbouring Lateral D, the assets of the former would represent a greater risk and would be prioritized higher between the two.

The process ultimately reviews the risks inherent in the current state of the system and recommend an optimized multi-year asset renewal plan, breaking down the investments by asset class. To yield more realistic investment portfolios, multiple constraint tools were considered to enable asset planners to prescribe maximum labour or vehicle usage thresholds, assign minimum investment levels to specific areas and others.

[10] https://www.icecalculator.com/build-model?model=interruption

Figure 3-22: Asset Intervention Prioritization Example



3.3.2.2 Risk-Based Planning Tasks

In preparation of this DSP, with assistance from METSCO, Entegrus facilitated a risk-based investment planning exercise that review a arrange of potential investment allocation scenarios over and beyond the current planning horizon. As described in Section 2.1.6.5, this analysis considered four broad scenarios involving the System Renewal and a portion of System Service portfolios, to help Entegrus understand the implications of its ongoing and future business planning decisions. The underlying analysis assumed a level of System Access and General Plant investments commensurate with the past trends and making special allowances for known or anticipated major projects over the Forecast Period. The results provided key insights into the implications of various investment trade-offs on the key aspects of Entegrus' performance over the coming decade.

Post customer engagement, the final planning approach focuses incremental spending on System Renewal critical asset replacement with some additional System Service automated switch restoration (smart grid) investments and a continuation of low voltage conversion programs with some extra increase in focus there. The customer engagement process is more fully described in Section 4.1.

3.3.3 Information Technology Asset Management Strategy

3.3.3.1 Overall Approach

Entegrus' Information Technology ("IT") assets keep the utility connected, help make operations increasingly efficient, and protect its data from cybersecurity threats. Entegrus sees its IT portfolio as the most dynamic portion of its asset base, as the rapidly evolving technological landscape and changing customer expectations (articulated both directly and through government policy) have drastically altered the scale, scope and complexity of the Entegrus' 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 a greater frequency, and are further complicated by the following factors that are less relevant to other utility plant:

- Changes in the vendor marketplace (e.g. M&As affecting future offerings or support level);
- Past vendor support experience;
- Emerging cybersecurity threats and newest prevention and response practices;
- Interoperability across major systems and versions;
- Change management work to ensure attainment of targeted benefits; and
- Requirements driven by customers' own technology choices.

Entegrus recognizes the impact that these additional considerations can have on the cost, complexity and performance of Entegrus' IT infrastructure. Moreover, having been involved in multiple M&A undertakings over the past two decades, Entegrus has had the benefit of seeing first-hand the implications of a variety of IT policy and strategy choices made by other utilities. Informed by these insights, Entegrus' own IT strategy is grounded in three pragmatic pillars:

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

3.3.3.2 Prioritizing in-house capacity.

A core facet of Entegrus' IT strategy involves prioritizing the acquisition of theoretical knowledge and practical capabilities by internal staff. While Entegrus understands that many of its peers outsource IT asset management to various degrees, its own approach prioritizes development of in-house capacity where doing so is practically feasible in the short-term and strategically beneficial from a longer-term perspective. Among the key benefits of insourcing are the consistent quality, efficient execution and rapid response to any short-term IT issues, and a more holistic approach to accommodating the longer-term strategic objectives. As discussed below, the amalgamation with STEI enabled Entegrus to grow its in-house IT capabilities with the addition of new personnel, creating additional opportunities for further skills and enhancement and greater specialization across the utility.

3.3.3.3 Investing in cybersecurity.

With the expansion of connectivity across system assets and the increasing complexity of utility IT ecosystems overall, cyberattacks are becoming a greater threat to business continuity. While Entegrus utilizes the regular security upgrades offered by its hardware and software vendors, Entegrus believes that the speed and sophistication at which cybersecurity threats are evolving warrants additional effort, informed by specific circumstances of a given IT environment. To this end, Entegrus invests additional internal resources to eliminate or reduce the cyberattack vulnerabilities across its assets and systems – to maximize proactive risk reduction. The approach to prioritize cybersecurity aligns with Entegrus' strategy to increase the skill and knowledge base of its internal resources. The utility believes that highly skilled and knowledgeable local resources are better positioned to detect and eliminate any threats and respond to emerging issues, given their intimate familiarity with the complexity of Entegrus' IT environments.

3.3.3.4 Maximizing the value of core business applications.

Recognizing that its IT operations and capital resources are limited, Entegrus maintains a pragmatic outlook on the optimal ways of enhancing the productivity across its business functions. Where evolving business needs can be addressed through better utilization of core business applications (i.e. the Microsoft Office suite), Entegrus seeks to avoid implementing purpose-built software solutions designed for a specific function. While maximizing the use of the core functions may entail offering enhanced implementation support to the user base, Entegrus sees doing so as a more prudent investment than procuring additional task-specific systems that complicate its IT environment and lead to incremental costs and additional vendor management effort. While this approach is not always practical, Entegrus seeks to make it as viable as possible by maintaining an aggressive version upgrade cycle. Doing so allows Entegrus IT staff to explore the incremental functionalities available in the newer versions to help their internal clients drive productivity gains with minimal incremental costs.

3.3.3.5 Hardware Asset Management

Like most of its peers, Entegrus is gradually investing in Hyper-Converged IT Infrastructure ("HCI"). HCI entails a software-defined approach to optimizing an organization's storage and processing capabilities in a way that shares the previously dedicated physical infrastructure functions across multiple virtualized machines. With a centralized software assigning tasks across virtualized machine units, an organization can capitalize on redundancies that would otherwise exist in dedicated units.

In performing its core functions, HCI infrastructure enables the utility to maximize the utilization of its existing storage and computing capabilities. This means that investments in HCI enable Entegrus to better pace their incremental capacity upgrade needs – and by extension, reduce their annual capital requirements. Moreover, the shared storage and computing functions enhance Entegrus' Disaster Recovery ("DR") capabilities during emergency situations.

With respect to physical hardware, Entegrus adheres to strict asset lifecycle guidelines prescribed in a dedicated policy that is reviewed within regular intervals. Table 3-7 showcases the lifecycles of commonly deployed hardware units in use by Entegrus.

Table 3-7: Hardware Lifecycle Policy Highlights

Hardware	Equipment Type	Lifecycle
Personal Computers	Laptop	4 Years
Mobile Telephony Devices	Cell Phone	2 Years
Servers	VxRail Hyperconverged	5 Years
Office Accessories	Various	10 Years

Entegrus has recently completed equipping its fleet vehicles with mobile tablets that enable staff to complete more administrative work in the field. Among others, targeted functionalities include the following streamlined activities:

- Digital access to safety certification and construction standard reference materials;
- On-site completion of inspection forms, work orders and outage investigation reports;
- Streamlined completion of crew time sheets and materials requisition forms;
- Real-time access to the GIS portal during construction or outage restoration work; and
- Simplified crew interaction with and tracking dispatch.

While not all functionalities are actively deployed at this time, Entegrus expects to explore and implement these and other mobile crew support tools over the Forecast Period.

Whenever possible, Entegrus also attempts to explore emerging technologies that meet a variety of its operating needs. One such pilot that is currently underway spans the software and hardware domains and involves a "Zero-Touch" (contactless) cellular signal-based security monitoring of Advanced Metering Infrastructure ("AMI"). The pilot is of particular interest is because it aligns with Entegrus' objectives of offering enhanced cybersecurity across its systems, in a manner that minimizes the incremental labour on the part of staff conducting the screening. Should the current pilot confirm the expected value add, Entegrus will explore deploying it utility-wide in the coming years.

3.3.3.6 Software Asset Management

In accordance with one of its strategic pillars noted above, Entegrus targets a frequent software upgrade cycle within its core Microsoft Office 365 suite of applications. Leveraging the terms of its Enterprise Agreement with Microsoft, the utility upgrades its Office 365-related applications as soon as practicable from the time of the newer versions becoming available. Maintaining short upgrade cycles on core business support applications allows Entegrus to enable additional productivity gains inherent in newest features. To ensure that staff maximize the use of the new functionalities, Entegrus seeks to offer comprehensive change management support. This approach aligns with Entegrus' goal of meeting as much of its business process support needs as possible using standard applications. In practice, this approach reduces the number of software applications deployed and helps reduce the ensuing OM&A and capital costs.

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) Entegrus attempts to utilize standard Off-The-Shelf technology and time any functional upgrades, capability expansion, or replacement decisions 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 vendor's future upgrade roadmap; and
- Alternatives solutions available on the marketplace.

3.3.3.7 Impact of the Entegrus-STEI Amalgamation

The recent amalgamation between Entegrus and the former STEI has benefitted the IT capabilities of both former entities. Consistent with its overall cost-minimization strategy described elsewhere in this Plan, the former STEI had been deferring a number of beneficial upgrades to its core IT hardware and software assets. As with the SCADA technology discussed in Section 2.1.1.1, the amalgamation with Entegrus enabled Entegrus – St. Thomas operations to benefit from upgrades and replacements carried out to bring the IT infrastructure in compliance with Entegrus' IT policy.

In several specific cases, the amalgamation enabled the new utility to capitalize on material savings, such as the switching of the former STEI's customer care operations onto Entegrus' in-house Harris NorthStar Customer Information System ("CIS") application. While the former STEI also utilized the Harris NorthStar system before the amalgamation, its software was hosted by a third party. Following the transition onto the Entegrus platform, the combined utility was able to realize the savings of approximately $300,000, while substantially expanding the scope of features available for the St. Thomas customer service representatives. Similarly, the migration of the St. Thomas customers onto the Entegrus customer portal has materially improved the overall user experience and the range of online offerings available to customers, drawing positive customer responses.

As noted elsewhere in this document, the amalgamation has also allowed, the combined utility to relocate Entegrus' previous Strathroy operations centre to nearby St. Thomas in 2021 Q4, accommodating both staffing complements within the existing St. Thomas facility. Aside from other benefits, this ongoing consolidation generates notable IT benefits, which include:

- Reduction in OM&A costs associated with broadband capacity rental in Strathroy;
- Expansion of connectivity between the two offices allowing for greater capacity for information transmission between sites;
- Improved service resiliency by way of two server clusters; and
- Faster response to IT issues through maintaining dedicated IT staff at both locations.

The above-noted benefits are largely a function of the size and more central location of the St. Thomas facility relative to the Strathroy office, which impacted the volume and cost of available connectivity.

Beyond the infrastructure cost and capacity optimization, however, the amalgamation with the former STEI enabled Entegrus to increase its staffing complement in the IT function, positioning the new entity to continue expanding the range and depth of its in-house knowledge and capabilities, consistent with its overall IT strategy.

3.3.3.8 Forecast Period Focus Areas

Aside from routine asset lifecycle upgrades, Entegrus expects to focus its 2021-2025 IT expenditures on the following activity areas:

- Finalization of the remaining post-amalgamation integration activities;
- Support for the major smart meter replacement program;

- Expansion of the HCI capabilities across both work centres;
- Renewal of cybersecurity support infrastructure;
- Expansion of storage capabilities to accommodate growing data requirements; and,
- Exploration of integrated software solutions across the HR, IT and Field Services Functions.

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

3.3.4 Facilities Asset Management Strategy

Entegrus' core Facilities Management priority is to maintain a safe, healthy and productive working environment for all of its staff and contractors, and a safe and welcoming setting for customers and other visitors. Entegrus' facilities portfolio includes operating centres in Chatham and St. Thomas (and previously a leased facility in Strathroy), along with the land and auxiliary buildings supporting its Distribution Stations. The 2021 Q4 integration of the Strathroy operating centre into the St. Thomas operating centre is further discussed below.

Figure 3-23: Entegrus Chatham Headquarters and Operating Centre (320 Queen Street)

Figure 3-24: Entegrus St. Thomas Operating Centre (135 Edward Street)

Figure 3-25: The former Entegrus Strathroy Operating Centre, 351 Francis Street

Note: Current Strathroy Staging Garage shown above at left. Former Strathroy office shown above at right.

3.3.4.1 Facilities Upkeep and Lifecycle Management Activities

Entegrus stores staff handle most day-to-day facilities maintenance tasks, with more significant repair or renovation tasks outsourced to a third-party contractor. Other specialist contractors perform periodic assessments and maintenance of the dedicated building systems, such as HVAC facilities.

The ensure continued architectural integrity of its key building systems, Entegrus engages an external architectural services firm to conduct comprehensive audits of its owned facilities on a five-year basis. The most recent audit of the Chatham facility took place in August 2020 and provided a number of recommendations, including the need to renew the building's roof included within the Forecast Period and other more minor recommendations that the utility will evaluate further over the Plan Period. A copy of this assessment is included in Attachment M. The assessment did not evaluate the Strathroy facility due to the planned transfer of its personnel to the St. Thomas Operations Centre in 2021 Q4, which also underwent an evaluation in August 2020. A copy of the most recent August 2020 St. Thomas assessment is included in Attachment N. The results of the St. Thomas facilities' assessment informed the scope of ongoing modification activities described below.

Having been in operations in its current form since 1986, Entegrus' Chatham headquarters feature several building systems where upgrades to contemporary standards will be needed. These include the electric heating equipment and legacy cooling tower infrastructure that Entegrus planned to convert to modern, energy efficient standards in the coming years. The timing of this work is likely to be deferred further, due to the discontinuation of provincial energy retrofit support programs, the focus on aging electrical distribution infrastructure and System Renewal and the post-merger emerging building needs associated with the St. Thomas operational centre discussed below.

3.3.4.2 Impact of the Entegrus-STEI Amalgamation

Entegrus has leased the Strathroy operating centre from the Municipality of Strathroy-Caradoc since the acquisition with the former Middlesex Power Distribution Company in 2005. Thereafter, the Entegrus/STEI amalgamation in 2018 resulted in Entegrus owning the St. Thomas operating centre (in addition to ownership of the Chatham operating centre). The St. Thomas and Strathroy facilities are located approximately 35 minutes from each other and post-merger, these operating centres together serviced the Entegrus northeast region communities. Notably, these northeast region facilities are both located approximately 75 minutes from the Chatham operations centre (which serves the Entegrus southwest communities.) As noted throughout this document, as of 2021 Q4, Entegrus will consolidate its three operating centres into two, by completing the transfer of Operations staff from the Strathroy operating centre to the existing St. Thomas facility. As noted below, Customer Service staff were transferred from Strathroy to St. Thomas in 2020.

The Entegrus portion of the leased Strathroy facility encompassed offices, staff cubicles, a meeting room, a garage and storage yard. This facility was leased from the Municipality of Strathroy-Caradoc and was adjoined – but physically separated – with another portion of the building occupied by municipal personnel.

In September 2020, Strathroy Customer Service personnel (4 employees) were transferred to the St. Thomas operations centre and integrated with St. Thomas personnel. In 2021 Q4, the Operations staff (7 Lines and Metering department employees) at the Strathroy facility will also transfer and integrate into the St. Thomas operating centre.

While Entegrus no longer leases office space in the Strathroy facility, nor base any staff out of Strathroy, it continues to lease the garage and yard as a staging facility to house selected rolling stock, equipment and supplies. This ensures that after hours response times can be maintained, given the geographic location of the Entegrus communities of Strathroy and Parkhill.

At the time of the Entegrus/STEI amalgamation in 2018, uncertainty existed with respect to the ability to consolidate the Strathroy and St. Thomas operations centres. The decision to consolidate the Strathroy operating centre into the St. Thomas facility in 2021 evolved for the following reasons:

- At the time of the merger, there were different unions representing operations staff in Strathroy and St. Thomas. Pre-merger, management notified the unions that for the purposes of efficiency and effectiveness, Entegrus intended to manage its northeast operating centres and serve its northeast customers as one region. Thereafter, management began a harmonization process and received numerous union grievances related to union territorial representation rights. In October 2019, one of the unions brought an application before the Ontario Labour Relations Board ("OLRB") seeking to extend the union's representation rights to all Entegrus union staff. Thereafter, a May 2019 OLRB decision granted sole representation rights to one of the unions. Completion and ratification of collective bargaining in December 2019 (by the Outside Bargaining Unit) and February 2020 (by the Inside Bargaining Unit), led to a two (2) collective bargaining agreement ("CBA") structures, as compared to the previous four (4) CBA structure.

- The aforementioned OLRB resolution provided the opportunity to achieve more critical mass of management and staff at a consolidated, harmonized facility owned by Entegrus (i.e. the St. Thomas operating centre). This assisted in the harmonization of cultures and processes and also allowed for enhanced back up capacity in the event of staff absences (i.e. for training, vacation, sick time).

- While there will be some annual savings from no longer leasing the office space portion of the Strathroy facility (while retaining the garage and yard), ultimately the consolidation of the Strathroy facility into the St. Thomas operating centre was driven by the above-noted opportunities to achieve critical mass and harmonization.

To accommodate this consolidation of staff in St. Thomas, Entegrus embarked on a four-phase facilities modification project to accommodate both the Strathroy and St. Thomas staffing complements and make the optimal use of space. The four phases spread the work out over time for the purposes of efficiency and budgeting. St. Thomas operating centre modification activities were comprised of the following work:

- **Phase 1:** Renovations to the Customer Service area to accommodate the former Strathroy Customer Service personnel, including converting former offices to cubicles and redesigning the Customer Service layout to allow for more physical distancing. The updates also included upgrades to fire alarm systems throughout the building. This phase was completed in August 2020, just prior to Strathroy Customer Service personnel transferring to St. Thomas.

- **Phase 2:** Installation of additional washroom facilities to accommodate additional personnel and ensure more physical distancing, and associated reconfiguration of the surrounding office area. This phase was completed in the fall of 2020.

- **Phase 3:** Physical adjustments and re-arrangements of furnishings to relocate staff in the Operations and Engineering areas to assist in the accommodation of the Operations personnel transitioning from the Strathroy building to the St. Thomas building. This phase is ongoing and will be completed in the fall of 2021.

- **Phase 4:** Renovations to the Operations, Engineering and IT areas to assist to better organize and streamline these areas for efficiency in accommodating the transferred staff. This phase is anticipated to be completed in the fall of 2022.

3.3.4.3 Forecast Period Focus Areas

Over the 2021-2025 Forecast Period, Entegrus expects to mostly limit the scope and scale of additional facilities expenditures to primarily general upkeep. The Larger projects that may be considered over the Forecast Period are the Chatham HVAC efficiency upgrades discussed above and roof upgrades to the Chatham Office identified in the most recent inspection report. Another larger project under consideration is the construction of an additional storage and garage facility – to safeguard vehicles, materials and supplies from theft and tampering by thieves and vandals – on the existing land parcel in Chatham.

As Entegrus 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 with respect to each individual land parcel.

3.3.5 Fleet Asset Management Strategy

As previously noted, Entegrus serves 17 communities located across an area of approximately 5,000 square kilometres and given this distance, stages its operations from facilities in two regions (northeast and southwest). The driving distance and time between the northeastern-most community (Parkhill) and southwestern-most community (Wheatley) amounts to approximately 170 km and two hours, respectively. Accordingly, Entegrus currently operates a fleet of 66 vehicles, as well as additional rolling stock units such as trailers and other miscellaneous mobile equipment units.

3.3.5.1 Asset Lifecycle Management

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

3.3.5.1.1 Heavy Vehicles (above 4,500 kg)

The Fleet Purchasing Policy currently prescribes the replacement of heavier diesel fuelled equipment like Single/Double Trucks, Digger Derricks and Dump Trucks once their recorded mileage exceeds 300,000 km, and/or the age of the unit exceeds 15 years of service. Beyond these higher-level thresholds, earlier replacement may be justified where a units annual O&M costs exceed 50% of their annual depreciation value, or where annual inspection and testing results (e.g. electrical or stress testing) are indicative of significant performance issues.

In select situations where units reach 15 years of age, but their mileage is substantially below the 300,000 km threshold, Entegrus may consider investing in life extension refurbishment work. However, refurbishment activities may only take place provided that 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, Entegrus' general policy is to avoid replacing more than one such unit per year. Where more than one large truck is eligible for replacement in a given year, the utility will replace the unit with a greater mileage reading.

3.3.5.1.2 Light Vehicles (below 4,500 kg)

Light gasoline and alternatively fuelled vehicles (pickup trucks, vans, cars) are eligible for replacement when their recorded mileage exceeds 200,000 km and/or their age exceeds 7 years in service. As with the heavy vehicles, a lifecycle extension beyond 7 years of service is feasible if the unit in question is deemed capable to remain in operation for another 3 years.

In recent years Entegrus attempted to extend the lifecycle of their lighter vehicles from 7 years up to 10 years. However, Entegrus' pilot revealed that doing so frequently leads to incurring major maintenance costs such as chassis or drivetrain overhauls, which reduced the financial rational for the extension of the lifecycle. Having encountered these costs on multiple occasions, Entegrus made a decision to keep the light vehicle age replacement threshold at 7 years.

3.3.5.2 Other Equipment

Entegrus 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 its mobile transformer / substation units. Instead, the utility identifies units for replacement on a case-by-case basis based on the units' individual condition assessment. 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 its overall fleet costs, Entegrus rents or contracts out the work involving special and infrequently used equipment, such as hydro vacuum trucks or directional drilling equipment.

3.3.5.3 Benchmarking its Fleet Lifecycle Management Policies

To ensure that its fleet management policies are consistent with its peers, Entegrus consulted the publicly available rate applications evidence from several Ontario utilities. Through this limited-scope verification exercise, Entegrus confirmed that its fleet lifecycle age thresholds are both 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.

3.3.5.4 Operating Costs Optimization

To manage its working capital costs, Entegrus maintains a minimum of spare inventory on site, instead purchasing all necessary spares through its maintenance contractors as the need arises. Entegrus currently hedges 50% of its Chatham fleet's fuel costs, while the Strathroy and St. Thomas vehicles fuel up at the local gas stations with no special arrangements at this time.

While the vast majority of Entegrus' lighter vehicles are purpose-equipped units utilized by specific departments, Entegrus typically maintains a small group of pool vehicles available to be signed out by staff to visit work sites, meet with customers or attend stakeholder meetings. Starting in 2020, these pool vehicles were temporarily repurposed to operational use in order to facilitate separate vehicles for operational field staff during the pandemic. This strategy was complemented by the temporary rental of additional vehicles.

In recent years Entegrus began to manage the utilization of its units by rotating certain fleet units between its Northeast and Southwest operational regions, since the distances between the communities served by the Chatham (Southwest) operating centre are greater than those in the Northeast operating centres. To this end, Entegrus occasionally moves the vehicles that sustain extensive use (above the expected average annual pace) in the Southwest region to the Northeast, where the average annual use may be lower. This entails another example of managerial innovation on the part of Entegrus to maximize the expected utility of all assets in its care.

3.3.5.5 Impact of the Entegrus-STEI Amalgamation

The amalgamation with the former STEI creates opportunities for longer-term fleet efficiencies through better utilization of the combined Northeast region stock, and potential rotation of units between the Northeast and Southwest fleet components as noted above. However, in the short-term, the amalgamation required Entegrus to allocate the bulk of its own annual fleet replacement capital to the St. Thomas units, given their overall condition at the time of the amalgamation. Entegrus expects to return to a regular and more regionally balanced fleet replacement cycle over the Forecast Period and does not foresee any material long-term risks with the temporary prioritization of unit replacements in the St. Thomas area.

In the Entegrus/STEI 2017 MAAD application (EB-2017-0212), annual capital synergies of $200k-$300k were anticipated related to sharing of specialized rolling stock. While this sharing does occur, the anticipated savings have not yet been realized due to the above-noted more immediate focus on upgrading the condition of the St. Thomas fleet.

3.3.5.6 Forecast Period Focus Areas

Barring any extraordinary circumstances, Entegrus expects to maintain a stable capital cost profile commensurate with its historical unit replacement volumes and costs.

3.4 System OM&A Expenditures and Relationship with Capital Work

To support the safe and reliable operation of its distribution system over the Forecast Period, Entegrus anticipates its annual System O&M expenditures to average approximately $5.3 million per year for the duration of the Forecast Period.

As noted at multiple junctures throughout this Plan, the post-amalgamation integration activities required Entegrus to invest significant capital and O&M resources to synchronize operations between the two former utilities, and in many cases – bring certain St. Thomas functions up to Entegrus' infrastructure and operations standards. Forecast O&M for 2021-2025 also reflects increased activities in the field to enhance safety related initiatives, specifically the Entegrus IHSA COR safety program and ESA maintenance inspections, as well as implementation of the voltage conversion approach described below. In addition, third party costs related to system maintenance and growth have increased since the onset of the pandemic.

Table 3-8: Entegrus Forecast Period System O&M

Line No.	Description	2021	2022	2023	2024	2025
1	System O&M	$4,745	$5,185	$5,328	$5,476	$5,628

As Entegrus continues its System Renewal work, particularly the low-voltage feeder conversion activities, it expects the reactive portion of its maintenance budget to decline over the longer-term, as newer assets are less likely to fail and substation retirements eliminate the station-related maintenance spend. However, given the current state of degradation in portions of the Legacy Entegrus distribution system, and the pace of the requisite System Renewal activities planned for the 2021-2025 timeframe, as more fully described in Section 1.5.1, Entegrus anticipates that any reductions in Reactive Maintenance spend due will be fully offset by the Risk-Based Maintenance spend associated with patrol-defined rectification of one-off deficiencies.

For its stations equipment, Entegrus conducts monthly visual inspections, along with a range of empirical tests that are conducted on regular cyclical basis (Dissolved Gas Analysis, Breaker Timing Tests, Battery Bank Tests, etc.) For its line infrastructure, Entegrus relies on a combination of a risk-based and reactive maintenance approach. The Risk-Based approach means that the actual System O&M work locations and expenditures are either identified through crew patrol activities, or recommendations from system planners based on the insights from the risk-based asset intervention analysis. The Reactive component is a product of in-service asset failures that warrant crew response and restoration.

4 Capital Expenditure Plan (5.4)

The capital expenditure plan should set out and robustly justify a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures.

A distributor's DSP details the program of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.

As noted above, a DSP must include information on prospective investments over a minimum five-year forecast period, beginning with the test year (or initial test year for certain Custom IR filings), as well as information on investments – planned and actual – over the five-year historical period prior to the initial year of the forecast period.

This section describes Entegrus' five-year capital expenditure plan over the 2021-2025 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 comparative analysis of past spend.

4.1 Customer Engagement and Preferences (5.4a)

A description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the capital expenditure plan

As described in Section 2.1.2, Entegrus conducted two phases of customer engagement for this DSP filing.

Phase 1 of customer engagement involved a third-party (Innovative Research) phone survey conducted near the outset of the DSP process in early March 2020, which was focused on determining the magnitude of upcoming EV and self-generation for planning purposes. The results of that survey, which are more fully described in Section 0, led to a conclusion that there would be minimal additional EV and self-generation uptake during the 2021-2025 Forecast Period. However, in anticipation of increased uptake beyond 2025, management has embarked on a strong incremental System Renewal focus in the 2021-2025 Forecast Period to lay the strong distribution system foundation needed for burgeoning customer interest in EV and self-generation in the future.

Phase 2 of the customer engagement occurred in June 2021 and July 2021 and was based on a second Innovative Research survey conducted by way of an online workbook, further supported by a phone-based reference survey. This phase of customer engagement was premised on the Entegrus plan to keep distribution rates unchanged throughout the 2021-2025 Forecast Period, aside from formulaic IRM adjustments. The focus of the workbook was focused primarily on three key areas: customer education (i.e. getting customers updated on Entegrus developments and the state of the system), preferences related to potential investments to be made in the 2021-2025 Forecast Period, and lastly, understanding customer priorities beyond 2025. This included other potential incremental investment alternatives that could potentially occur over the Forecast Period, but which would not impact 2021-2025 distribution rates.

Phase 2 customer engagement and its results are described below in detail.

4.1.1 Customer Engagement Methodology

At the outset of Phase 2 of customer engagement, third party provider Innovative Research conducted a telephone reference survey amongst a random sampling of residential and small business customers. This reference survey allowed for a better understanding of the demographic makeup of the Entegrus customer base to later facilitate sample validation and weighting of the online workbook results.

Meanwhile, Entegrus worked in collaboration with public opinion research and consultation firm Innovative Research to design an online workbook to provide customers with an overview of Entegrus asset management considerations. The workbook would be focused on three key areas: customer education (i.e. getting customers updated on Entegrus developments and the state of the system), preferences related to potential investments to be made in the 2021-2025 Forecast Period, and lastly, understanding customer priorities beyond 2025. This included other potential incremental investment alternatives that could potentially occur over the Forecast Period, but which would not impact 2021-2025 distribution rates. In conveying these planning considerations, Entegrus would seek to confirm customers' views on the needs and objectives that should be prioritized.

Following sample validation based on the results of the reference survey, in June 2021 the finalized online workbook was sent via e-mail blast to all Entegrus customers with an email address on record. The residential and small business online workbooks featured two input streams:

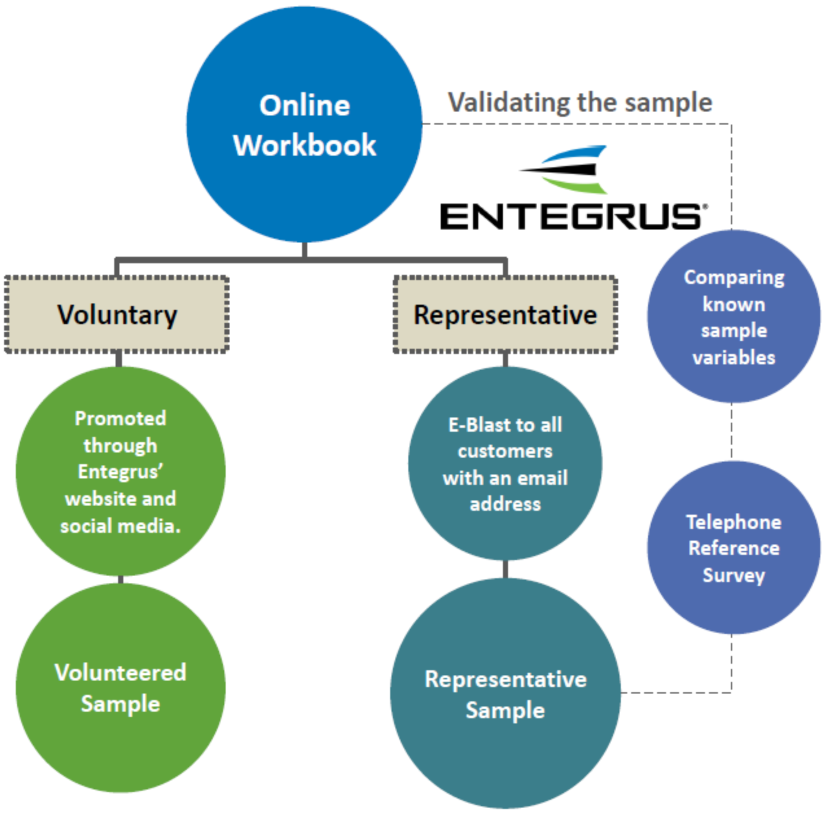
1. The representative stream, which ensured a representative sample of customers was engaged, allowing for the generalizability of findings.
2. The voluntary stream, which created an open process that allowed anyone who wanted to be heard an opportunity to participate, including those who have not provided the utility with an email address.

Similarly, all GS>50 kW customers with an email address on file were invited to participate in the online workbook, accessible through a unique URL sent directly to customers. There was no voluntary stream for the GS>50 kW version of the workbook.

In the representative stream, each customer received a unique URL that could be linked back to their annual consumption, region and rate class. In total, the workbook was sent to 25,991 customers (of a total of 60,588 customers) through an e-blast from Innovative Research. Beyond the initial e-blast, customers in all rate classes were sent multiple reminder emails to encourage participation. Additionally, Entegrus placed follow-up telephone calls with GS>50 kW to encourage survey participation.

Ultimately, reported results are based on the representative stream. A diagram of the above-described methodology is shown in Figure 4-1 below.

Figure 4-1: Sample Validation Diagram



4.1.1.1 **D**emographics and Response Results

As described above in terms of the representative and voluntary sampling, a concerted effort was made to ensure that all customers – regardless of where they live or operate, or how much electricity they use – had an equal opportunity to participate.

Dividing the Entegrus service territory into distinct regions allowed Innovative Research to ensure that no one region was over or underrepresented in the survey sample. Although Entegrus has two rate zones (Entegrus – Main and Entegrus – St. Thomas), for the purpose of study representation only, four regions were established: Chatham, Strathroy, St. Thomas and Rest. These regions were based on population density and further analyzed based on the number of residential and small business customers in each region. (Note: Key engagement findings and preferences were then segmented consistent with the two rate zones for analysis: Entegrus-Main and Entegrus-St. Thomas.)

As is more fully described in Attachment B by comparing the overall population to the sample of that population with email addresses, it was apparent that no group was substantially underrepresented in the email sample.

Ultimately, the completion of the survey process yielded the response results shown below in Table 4-1.

Table 4-1: Summary of Entegrus Survey Methodology & Results

Customer Group	Methodology	Unweighted Sample Size	Field Dates
Residential	Telephone	n=409	June 3 – 25, 2021
Small Business	Telephone	n=103	June 3 – 25, 2021
Sample Validation and Telephone "Reference" Surveys: n=512			
Residential	Online Voluntary	n=8	June 30 – July 20, 2021
Small Business	Online Voluntary	–	June 30 – July 20, 2021
Residential	Online Representative	n=3,856	June 21 – July 20, 2021
Small Business	Online Representative	n=160	June 21 – July 20, 2021
Commercial (GS > 50 kW)	Online Representative	n=22	June 21 – July 20, 2021
Online Workbooks: n=4,046			
Total Customers Engaged as Part of Entegrus' Customer Engagement: 4,558			

4.1.1.2 **Customer Engagement** Diagnostics

Entegrus sought to understand whether customers had a favourable impression of the utility's efforts to gather feedback on its plans and if there are areas that could be improved upon for future engagements.

Overall, most customers across all three rate classes who completed the online workbook had a favourable impression of the exercise.

Table 4-2: Customer Overall Impression of Workbook

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential	Small Business	GS >50 kW
Favourable (Very + Somewhat)	**86%**	**87%**	**20/22**
Unfavourable (Very + Somewhat)	**6%**	**9%**	**1/22**
Don't know	**7%**	**4%**	**1/22**

Further, approximately 4 of 5 customers across all three rate classes who completed the online workbook felt that "just the right amount" of information was provided.

Table 4-3: Customer Impression of Volume of Information Provided in Workbook

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
Too little information	**4%**	**6%**	**0/22**
Just the right amount	**82%**	**79%**	**19/22**
Too much information	**14%**	**16%**	**3/22**

4.1.2 Key Customer Engagement Findings and Customer Preference

4.1.2.1 Customer Satisfaction with Services Provided by Entegrus

Overall, the results of customer engagement showed that Entegrus customers are satisfied with the services that they receive, with only a very small proportion expressing dissatisfaction.

Table 4-4: Customer Satisfaction with Services Provided by Entegrus

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
Very satisfied	39%	39%	9/22
Somewhat satisfied	34%	36%	6/22
Neither satisfied nor dissatisfied	20%	19%	3/22
Somewhat dissatisfied	5%	4%	4/22
Very dissatisfied	2%	1%	0/22
Satisfied (Very + Somewhat)	**73%**	**75%**	**15/22**
Dissatisfied (Very + Somewhat)	**6%**	**5%**	**4/22**

Additionally, there are only very small differences between rate classes and between the Entegrus – Main and Entegrus – St. Thomas rate zone territories (see Attachment B).

4.1.2.2 Awareness of Distribution Charge Increase Over Next 5 Years

Given the anticipated customer preference for maintaining reasonable distribution rates, a key priority was to update customers about the approximate distribution rate increases they could expect based on the proposed 2021-2025 Forecast Period Plan.

Ultimately, the table below shows that fewer than 1-in-5 customers were aware in advance that the distribution charge for the typical bill is estimated to increase by less than the rate of inflation (i.e. 2.05%) for the next five years, until 2026.

Table 4-5: Awareness of Distribution Charge Increase Over Next 5 Years

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential	Small Business	GS >50 kW
Yes	18%	14%	3/22
No	78%	83%	18/22
Don't know	4%	2%	1/22

4.1.2.3 Familiarity with Entegrus Digital Tools

In general, the customer engagement process demonstrated that customers have good awareness of Entegrus digital tools – particularly the Entegrus.com website which was updated in late 2020.

However, the findings in terms of the new online outage map (launched simultaneously with the updated website in late 2020) show that there is an opportunity to increased customer awareness of this tool, particularly in St. Thomas. Please see Attachment B for more details.

Table 4-6: Customer Familiarity with Entegrus Online Outage Map

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential (Main / St. Thomas)	Small Business	GS >50 kW
I have used it before	43%/23%	33%/7%	13/22
I have heard of it, but have not used it before	26%/26%	32%/35%	3/22
I have never heard of it before	31%/51%	35%/58%	6/22

4.1.2.4 Investment Plan Choices

Another key priority of customer engagement was to gather feedback on preferences related to potential incremental investments not in the "status quo" plan, but which could potentially occur over the Forecast Period without impacting 2021-2025 distribution rates, but which could impact rates in 2026 and beyond.

The workbook explained that under Ontario regulatory policy, an option exists for utilities to apply for additional rate increases (i.e. an Incremental Capital Module, or ICM, application) for discrete projects that are prudent, needed and not supported by existing rates. However, it was further explained that Entegrus had elected to continue to make certain System Renewal reliability investments without asking customers for rate increases at this time, to align with the objective of keeping distribution rates affordable in 2021-2025.

The workbook went on to explore two specific potential investments: (a) additional line modernization and station decommissioning, and (b) the implementation of automated switches in the cities of Chatham and St. Thomas to create a dynamic smart grid system. It was noted in the workbook that these alternative incremental investments, considered for 2024 and 2025, would not impact customer rates until the next planning period between 2026 and 2030.

The survey results ultimately determined that for both potential investments, a majority of customers supported an approach that invests beyond what is currently included in Entegrus' "status quo" plans or what is currently included within current rates. A description of the two potential incremental investments is presented below, along with associated customer feedback.

4.1.2.4.1 **System Conversion** (Lines Modernization / Station Decommissioning) Alternatives

The workbook explained that about 15% of Entegrus' customers are serviced by older low voltage (4 kV) lines, which have an increasing risk of failure. It was noted that these 4 kV lines are supported by distribution stations, which have less capacity than modern (27.6 kV) lines. It was also noted that due to their limited capacity, 4 kV lines are not suited for smart grid technology or customer-owned generation.

It was noted that Entegrus has been focused on converting the 4 kV systems to the 27.6 kV technology, with focus on the following benefits: (i) improved reliability through the new lines and transformers, (ii) increased capacity on each line to support customer growth, smart grid technology, and customer owned electricity generation; and (iii) improved outage restoration from the enhanced back up and availability of tie points at this higher voltage level.

It was further explained that Entegrus currently has 19 of these stations in service and to balance other asset management priorities, Entegrus was originally targeting the removal of 4 stations by 2025 (a pace at which all the 4 kV lines and stations would be decommissioned and replaced beyond 2040) in the base plan. Lastly, it was noted that because this equipment does not pose an urgent threat to reliability, historically as unforeseen distribution system priorities emerged, it has been the practice of Entegrus to divert resources away from these conversion projects to resolve more pressing priorities.

After being provided the above-noted details, customers were asked which of the following options they preferred, as described in Table 4-7 below.

Table 4-7: Customer Workbook System Conversion (Lines Modernization / Station Decommissioning) Alternatives

Option	Description	Expected Outcome
Accelerated Paced Line Modernization *Additional $0.50 - $0.70 per month starting in 2026*	Line modernization to allow the removal of 6 low voltage Stations to occur from 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2035 • Reduce risk of deterioration of reliability • Avoid some Station maintenance costs.
Faster Paced Line Modernization *Additional $0.25 - $0.35 per month starting in 2026*	Line modernization to allow the removal of 5 low voltage Stations to occur in 2021-2025 regardless of other priorities.	• Complete line modernization of all low voltage equipment and Station decommissioning by 2040 • Risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.
Status Quo *Within current rates*	Continue to target line modernization to allow removal of 4 low voltage Stations, to occur in 2021-2025. Allow for diversion from this plan if other priorities emerge.	• Maintain low voltage Stations beyond 2040 • Higher risk of deterioration of reliability continues • Escalating Station maintenance versus obsolescence.

The results of the representative workbook survey are summarized in the table below.

Table 4-8: Results of System Conversion Alternatives Question

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential (Main / St. Thomas)	Small Business (Main / St. Thomas)	GS >50 kW (Combined)
Accelerated pace	31% / 30%	36% / 22%	4/22
Faster pace	26% / 27%	29% / 34%	9/22
Status quo	42% / 43%	36% / 45%	10/22

The results show that while a plurality of customers support the status quo, a majority of customers across rate classes support some level of accelerated investment to decommission more stations over the same period, knowing that it would cost them additional money starting in 2026.

For residential customers, there is a strong correlation between a customer's likelihood to support an option that would result in increased rates and their individual financial circumstances (see Attachment B). Those who say their electricity bill has a significant impact on their household finances are much more likely to support the status quo option presented. That said, 43% of customers whose bill has a significant impact on their finances still support some level of additional investment.

4.1.2.4.2 Automated Switches Alternatives

The workbook explained that automated switches can allow Entegrus to automatically reroute power during outages and planned maintenance, reducing the length of time customers are without power and reducing reliance on crews travelling to the site to physically reroute power. It was noted that when this automatic rerouting occurs, impacted neighbourhoods can experience an outage lasting less than one minute, rather than a lengthier interruption.

It was also noted that Entegrus has recently used automated switch technology to target outlying (dual feed) communities experiencing poor reliability due to loss of supply. It was explained that these communities are served by two long lines from the provincial transmission system, and the technology allows the two lines to automatically back each other up when one line experiences an outage, eliminating the need for manual intervention.

It was explained that Entegrus now sees an opportunity to roll this technology out in larger cities that have many interconnecting lines that can form dynamic grids, and that doing so would offer multiple alternative paths for electricity to flow, bypassing the fault and avoiding potential widespread outages. This switching scheme would help reduce the outage duration and help create a more integrated system to help facilitate future technological advancements, including EV's and customer generation.

Lastly, it was noted that to balance spending priorities, the Entegrus plan was limited to install of 6 automated switches between 2021-2025. However, it was noted that there was an opportunity for a broader roll out of intelligent switches in the larger communities of Chatham and St. Thomas. In these communities, the higher density allows more opportunity to increase connectivity and create a dynamic smart grid.

After being provided the above-noted details, customers were asked which of the following options they preferred, as described in Table 4-9 below.

Table 4-9: Customer Workbook Automated Switching Alternatives

Option	Description	Expected Outcome
Increase to Higher Intelligent Switch Density in Chatham & St. Thomas *Additional $0.40- $0.70 per month starting in 2026*	Install an additional 18 switches in Chatham and an additional 10 switches in St. Thomas	Reduce outage duration by about 20% - 25% and outage frequency > 1 minute by about 30% - 40%
Increase to Medium Intelligent Switch Density in Chatham & St. Thomas *Additional $0.20 - $0.35 per month starting in 2026*	Install an additional 11 switches in Chatham and an additional 6 switches in St. Thomas	Reduce outage duration by about 15% - 20% and outage frequency >1 minute by about 25% - 30%
Status Quo – Stay with Low Intelligent Switch Density in Chatham & St. Thomas *Within current rates*	No additional investment in intelligent switches beyond the few in the current plan.	Increased risk of potential deterioration of reliability in the medium term.

The results of the representative workbook survey are summarized in the table below.

Table 4-10: Results of Automated Switching Alternatives Question

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential (Main / St. Thomas)	Small Business (Main / St. Thomas)	GS >50 kW (Combined)
Higher switch density	31% / 30%	27% / 23%	5/22
Medium switch density	37% / 42%	46% / 48%	11/22
Status quo	32% / 28%	27% / 29%	6/22

The results show that with regard to this automated switching (smart grid) technology, a strong majority of all customers support additional investment. This is shown by 69% of residential and 72% of small business customers supporting investments in either medium or high-density intelligent switches in Chatham and St. Thomas.

And again, as shown in Attachment B, when looking at residential customers who say their electricity bill has a significant impact on their household finances, we see that a majority of these customers also support some level of additional investment.

4.1.2.5 Planning for the Future: Beyond 2025

4.1.2.5.1 General Priorities

In addition to seeking customer feedback on current investment priorities, the customer engagement process also focused on gathering feedback on priorities beyond 2025.

As anticipated, the results showed that Entegrus customers expect their utility to focus on the core business of providing reliable electricity at reasonable rates. More specifically, in terms of general priorities, most customers feel that, above all else, Entegrus should focus on delivering electricity at reasonable rates. This is the number one priority across all three rate classes. Ranking just below rates, most customers feel that Entegrus should be focusing on ensuring reliable electricity service. In fact, reliability is the top priority for more than 1-in-5 residential and small business customers. For commercial and industrial customers, 11 out of 22 rank reliability as their top priority, compared to 8 out of 22 who see rates as the most important.

The following representative workbook survey results show customer rankings of general priorities (in terms of the share of customers who select the priority in their top 3).

Table 4-11: Customer Ranking of General Priorities Beyond 2025

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	**Representative Workbook**		
	Residential	Small Business	GS >50 kW
Delivering electricity at reasonable rates	88%	90%	20/22
Ensuring reliable electricity service	74%	79%	19/22
Ensuring the safety of electricity infrastructure	34%	28%	4/22
Helping customers with conservation and cost savings	31%	28%	4/22
Providing quality customer service	26%	27%	5/22
Minimizing the impact on the environment	24%	23%	4/22
Enabling customer choice to access new electricity service	15%	17%	7/22
Proactively preparing for community growth	8%	10%	3/22

A takeaway from this feedback is that customers clearly do not expect Entegrus to just focus on one outcome. In fact, a majority of both residential and small business customers feel that, beyond rates and reliability, providing quality customer service, ensuring the safety of electricity infrastructure, and helping customers with conservation and cost savings are all very important.

4.1.2.5.2 Reliability Priorities

In addition to general priorities, customers were also asked about their preferences towards the various types of priorities that Entegrus could focus on to address system reliability.

When it comes to reliability outcomes, customer preference varies depending on rate class. The residential priority is closely divided between the length and frequency of outages during severe weather events and reducing the overall number of outages. While small business customers have the same three overall priorities, they place a stronger emphasis on reducing the overall number of outages lasting longer than one minute. More than 1-in-3 small business customers see reducing the number of outages as the top priority, compared to 1-in-4 residential customers. For commercial and industrial customers, the top two priorities are related to the number of outages, both those lasting longer than one minute as well as those lasting less than one minute.

The following representative workbook survey results show customer rankings of priorities Entegrus could focus on to address system reliability.

Table 4-12: Customer Ranking of System Reliability Priorities Beyond 2025

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential	Small Business	GS >50 kW
Reducing the length of time to restore power during severe weather events	81%	68%	11/22
Reducing the # of outages during severe weather events	74%	68%	7/22
Reducing the overall # of outages lasting >1 minute	66%	74%	21/22
Reducing the overall length of day-to-day outages	43%	52%	11/22
Reducing the overall number of outages lasting less than one minute	36%	38%	16/22

Prior to ranking various priorities, including reliability, customers were asked about their overall satisfaction with the services that they receive from Entegrus. Overall, customers are satisfied with Entegrus and their preferences around reliability outcomes are generally dependent on individual circumstances, as well as rate class.

4.1.2.5.3 Technology Priorities

Lastly, customers were asked about their sentiments towards various types of investments in technology. When it comes to investments in technology, there are essentially four tiers.

In the first tier, most customers, regardless of rate class, feel that Entegrus should be focusing on new technology that can help find efficiencies.

In the second tier, customers would like to see Entegrus focus on new technology to improve reliability, or technology that can help customers better manage their usage. In fact, a plurality of small business customers see technology to improve reliability as their top priority.

Grouped in the third tier is technology to reduce environmental impacts and technology that enables customer choice.

Finally, very few customers in any rate class see new technologies that make it easier to interact with Entegrus as a top priority. Again, most customers are largely satisfied with the services that they currently receive from Entegrus and would like to see focus placed on rates and reliability rather than customer service features.

The following representative workbook survey results show customer rankings of technology priorities Entegrus could focus on to address system reliability.

Table 4-13: Customer Ranking of Technology Priorities Beyond 2025

Summary of Findings *n-size shown for GS>50 customers due to insufficient sample size*	Representative Workbook		
	Residential	Small Business	GS >50 kW
New technology that can help Entegrus find efficiencies	85%	83%	18/22
New technology that would reduce the # and length of outages	64%	66%	19/22
New technology that can help customers better manage usage	62%	57%	16/22
New technology to reduce environmental impact	42%	43%	4/22
New technology that enables customer choice	31%	34%	7/22
New technologies that make it easier to interact with Entegrus	16%	19%	2/22

4.1.3 Reflecting Customer Engagement Results in DSP and Capital Expenditure Plan

4.1.3.1 Balancing Affordable Distribution Rates and Reliability Investments

The customer engagement results continue to reinforce that a predominant customer preference is to keep distribution rates affordable while focusing on reliability investments. This is consistent with management's ongoing understanding of the Entegrus customer base's needs and preferences. Accordingly, this feedback aligns with the key premises that management brought into the initial design phase of this DSP filing.

The 2021-2025 Forecast Period investment portfolios, particularly System Renewal and System Service, were premised on this trade-off and Entegrus believes the DSP accommodates this convergence of needs and preferences. More specifically, the DSP involves a primary proactive replacement of aging distribution infrastructure and continued modernization of low-voltage feeders – which will improve weather resilience, reduce losses, and enable future savings through avoided replacement of distribution stations. This is balanced with a reactive (run-to-fail) replacement of other (typically dispersed) system assets, budgeted based on risk-based intervention planning, but executed on the basis of specific results of inspections and/or actual failures that cause outages. The plan is further supported by targeted Investments in Distribution Automation ("DA") technology to reduce the duration of outages affecting Entegrus customers and help pace the volumes of asset renewal that may otherwise be considered. This approach assists in mitigating 2021-2025 Forecast Period rate impacts for customers.

As noted earlier in this DSP filing, Entegrus does not plan for any ICM applications in the 2021-2025 period.

4.1.3.2 Additional Investments in System Conversions and Automated Switches

The customer engagement process was revealing in its determination that, although affordable distribution rates are a key customer priority, a majority of customers (across all financial circumstance segments) have a preference for incremental investment in 2024-2025 in relation to two specific projects. These projects pertain to the additional system conversion work (i.e. line modernization and station decommissioning) and incremental automated switching in Chatham and St. Thomas, as described above. As was described in the customer engagement workbook, these incremental investments will not impact customer rates until the next planning period (between 2026 and 2030). This also means Entegrus will forego the portion of potential return on investment that would otherwise have been earned in 2024 and 2025 by way of potential ICM applications.

In reviewing and responding to the customer preferences regarding specific to the additional system conversion work, it is notable that this customer preference extends across all rate classes and financial circumstance segments, whereby customers support some level of accelerated investment (see Table 4-8 above). Based on review of these results, management will pursue the "faster pace" scenario (rather than the "status quo" or "accelerated pace" scenarios). Accordingly, this DSP filing has been updated to include expansion of the previous lines modernization (Voltage Conversion) project to include one additional low voltage station removal (and associated line modernization), thus increasing the number of low voltage station removals from 4 to 5 over the 2021-2025 Forecast Period, with the additional removal occurring in 2024/2025. The additional cost per customer of $0.25 - $0.35 per month starting in 2026 equates to a planned incremental System Renewal investment cost of $2.3M, to be split 50%/50% between 2024 and 2025. As described in Section 4.4.5.2, the timing of commencement of this project will be re-examined in 2024 based on prevailing circumstances at that time, including reliability metrics and the level of capital requirements at that time. Additional details on Voltage Conversion (System Renewal) are described in Attachment O, Project 2.8.

In reviewing and responding to the customer preferences specific to the implementation of incremental automated switches in Chatham and St. Thomas, it is again notable that across all rate classes and financial circumstance segments, a strong majority of all customers support additional investment (see Table 4-10). Based on these results, management will pursue the "increase to medium intelligent switch density" scenario (rather than the "status quo" or "higher switch density" scenarios). Accordingly, this DSP filing has been updated to include the installation of 11 additional switches in Chatham and 6 additional switches in St. Thomas in 2024 and 2025. The additional cost per customer of \$0.20 - \$0.35 per month starting in 2026 equates to a planned incremental System Renewal investment cost of \$1.25M, to be split 75%/25% between 2024 and 2025. As described in Section 4.4.5.2, the timing of commencement of this project will be re-examined in 2024 based on prevailing circumstances at that time, including reliability metrics and the level of capital requirements at that time. Please see Section 4.1.3.2 for details on System Automation (System Service), as well as Attachment O, Projects 3.4. It should be noted that while St. Thomas reliability metrics are currently favourable by comparison to Entegrus – Main, recent growth levels in St. Thomas will result in more customers being served off existing feeders. Accordingly, the segmentation benefits of the automated switches assist in mitigating the rising customer density in the St. Thomas distribution system, by establishing additional paths for alternative and automated distribution routes.

Although questions to customers about reliability prioritization preferences were asked in the context of beyond 2025 (see Table 4-12), management noted parallels between customer reliability prioritization preferences and the additional 2024/2025 projects discussed above. Specifically, the additional system conversion project in 2024/2025 ties to a primary customer objective of "reducing the number of outages during severe weather events". By replacing additional aged infrastructure with new, modern technology, and making conversions an ongoing key focus, it is anticipated that the distribution system will be more weather resilient.

Further, the incremental automated switches project in Chatham and St. Thomas in 2024/2025 tie to the other primary customer objectives of "reducing the length of time to restore power during severe weather events" and "reducing the overall number of outages lasting > 1 minute". The creation of a dynamic distribution grid will allow Entegrus more opportunity to isolate temporary system faults within smaller segments of the system and thereby get the power back on quicker to more customers.

4.1.3.3 Continuation of Power Quality Investigations

The reliability prioritization preferences of GS>50 kW customers for 2025 and beyond (see Table 4-12) – particularly in terms of the focus on "reducing the overall number of outages lasting less than one minute" – supports the continuation of the Entegrus power quality investigation process.

This process was initially established in 2016 when a subset of C&I customers reported transient power quality issues – particularly amongst those operating increasingly sophisticated and sensitive equipment. At that time, Entegrus implemented the program to track and help resolve any power quality issues performance. This included installation of advanced power quality meters in select areas where customers voiced associated concerns. Aside from monitoring the meter results, Entegrus actively worked with the upstream supplier to ensure that any potential power quality issues arising upstream could be addressed. In the majority of cases, Entegrus' investigations concluded that the causes of concerns were unrelated to the performance of its own equipment or renewable generation facilities connected to it and also assisted customers in ultimately resolving these issues.

Although Entegrus has recently seen less demand for power quality investigations (see Section 2.3.3.1.3), the most recent customer engagement results amongst GS>50 kW customers support the continuation of this program.

4.1.3.4 Customer Online Outage Map Awareness

As noted above, reliability is a major area of focus for Entegrus customers. In late 2020, Entegrus enhanced its previous online outage map offering and at the same time, extended this technology to incorporate St. Thomas. The customer engagement process showed that there is an opportunity to increase customer awareness of the new Entegrus online outage map and its benefits.

The results in Table 4-6 above show that there is somewhat more awareness of the tool in the Entegrus – Main rate zone, which may reflect that St. Thomas did not historically have outage map capabilities, and therefore this technology is newer to customers in the Entegrus – St. Thomas rate zone. This also may be reflective of the differences in outage experience between the two rate zones; reliability experience is key to customers initiating a review of the online outage map.

In response to this feedback, Entegrus will design and launch a customer marketing campaign about the online outage map and its benefits to launch in the fall of 2021. This campaign will cover the entire service area, with specific emphasis on St. Thomas.

4.1.3.5 Distribution System Planning Beyond 2025

In terms of general priorities planning for the future beyond 2025, customers want Entegrus to continue to keep distribution rates affordable while also ensuring reliability. However, in doing so, customers do not expect Entegrus to just focus on one outcome (see Table 4-11). Beyond rates and reliability, providing quality customer service, ensuring the safety of electricity infrastructure, and helping customers with conservation and cost savings are all vital. It is further recognized that different customer rate classes and segments can have different priorities which need to be balanced. For example, in addition to the above expectations, for Entegrus GS>50 kW customers, power quality and mitigation of momentary outages also remain key focus areas.

Customer technology priorities for the future continue to be on affordable rates with simultaneous focus on reliability. Specifically, the key technology priorities are "New technology that can help Entegrus find efficiencies and reduce customer costs", "New technology that would reduce the number and length of outages" and "New technology that can help customers better manage their electricity usage". Section 2.1.3.1 and Section 2.1.6.4 provide examples of managerial innovation in the use of technology / analytics that has help Entegrus sustain customer service while maintaining reasonable rates.

Entegrus recognizes that, based on the customer feedback about technologies for the future, management's pragmatic approach to technology should be continued in the future in terms of the overall investment planning process beyond 2025.

4.2 SYSTEM DEVELOPMENT OVER THE FORECAST PERIOD (5.4B)

A description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, climate change adaptation, grid modernization and/or the accommodation of forecasted REG projects

4.2.1 Ability to Connect New Load/Generation

Over the next five years, Entegrus expects the bulk of its system load to occur within its two largest load centres of Chatham and St. Thomas, driven by a combination of new residential subdivisions and new commercial and industrial developments. The loading in St. Thomas has reached the point where all the available feeders are heavily loaded during peak periods. Entegrus now experiences periods of time where no transfer capacity remains in the event of certain single points of failure during peak loading. The number of hours and failure points leading to this condition is expected to grow over time, regardless of whether the recent unprecedented residential growth trend in St. Thomas slows. To remediate this system condition, and allow for continued growth in the community, Entegrus plans to construct a new feeder off the St. Thomas Edgeware transmission station. Entegrus is also investigating other solutions to address this loading capacity issue in St. Thomas, but a decision regarding these alternatives has yet to be made. An additional feeder at Kent TS in the Chatham area has also been studied and will be required if customer loading materializes. These projects are described in Section 4.2. As a result of the Edgeware project, Entegrus expects to add connection capacity for an additional 15 MW of load in the St. Thomas area over the coming years.

Aside from the impact of these anticipated System Service investments, the utility expects to add feeder-level connection capacity through its System Renewal work, as Voltage Conversion activities are expected to increase local connection capacity in several parts of its system. As a result of the conversion work, including the additional work added after customer engagement, Entegrus also expects to decommission up to five distribution substations over the Forecast Period.

In light of the changes to the provincial generation procurement programs over the recent years, the level of interest for generation connections within Entegrus' service territory has materially subsided. As of the writing of this document, there are two energy storage projects in its generator / non-load interconnection queue. Entegrus has issued Connection Cost Recovery Agreements (CCRAs) to the proponent for both projects. Beyond these two projects, the utility possesses no information to indicate any generation connection limitations emerging over the Forecast Period.

4.2.2 Load and Customer Growth

The table below shows the load forecast across the Entegrus service territory. While the economic impact of COVID-19 adds significant uncertainty to the task of load forecasting, the utility sees no other practical alternative aside from basing its results on the latest historical trends and specific information from local sources (e.g. municipalities, developers) available to it.

Table 4-14: 2021-2025 Entegrus Load Forecast

Transformer Station Name	DESN ID (e.g. T1 / T2)	DESN ID (e.g. BY)	Historical Data (MW) 2016	2017	2018	2019	2020	Forecast (MW) 2021	2022	2023	2024	2024	Power Factor
Region: Chatham													
Kent TS*	T1/T2/T3/T4	BY-EZ	93.1	89.7	96.7	89.5	97.2	97.4	98.0	98.8	99.4	99.8	95
Wallaceburg TS	T1/T2	BY	28.2	25.3	29.1	25.2	26.5	26.8	26.9	27.0	27.1	27.2	92
Leamington TS	T3/T4	BY	-	2.5	2.8	2.8	3.0	3.0	3.0	3.1	3.1	3.1	95
Kingsville TS	T1/T3/T6	BY	2.7	-	-	-	-	-	-	-	-	-	95
Bothwell DS	-	-	1.3	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	95
Dutton DS	-	-	1.8	1.7	1.8	1.8	2.1	2.2	2.3	2.3	2.3	2.4	95
Tilbury DS	T1/T2	B	15.7	14.9	15.9	16.1	16.2	16.3	16.4	16.5	16.6	16.6	94
Region: Strathroy													
Strathroy TS	T1/T2	BQ	48.6	25.4	22.7	31.8	32.5	32.6	32.7	32.7	32.8	32.8	95
Longwoods TS	T13/T14	QJ	6.0	6.0	6.2	6.2	5.9	6.0	6.0	6.1	6.1	6.1	92
Centralia TS	T1/T2	Z	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	95
Mount Brydges DS	-	-	2.3	2.6	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	95
Newbury	-	-	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	95
Region: St. Thomas													
Edgeware TS	T1/T2	BY	58.6	46.6	51.9	58.2	66.2	68.0	68.8	69.7	70.2	71.0	95

** Note, Kent TS historical and forecast values assume Large Use Standby customer running at full contracted capacity of 10.2MW.*

The table above includes Entegrus' anticipated addition of a new supply feeder and associated breaker position at Hydro One's Edgeware TS and the potential Kent TS project, expected to be required to accommodate the anticipated continued residential and commercial developments in St. Thomas Area. While the impact of COVID-19 makes near-term load forecasting work more challenging, Entegrus will continue to monitor any developments and update plans on an ongoing basis.

Should the developments over the Forecast Period indicate the need to materially revise the load forecast and/or augment the scope and timing of any of the associated investments, Entegrus will consider the new information and re-allocate the funds previously earmarked for this work across other portfolios.

4.2.3 Grid Modernization

Entegrus expects to undertake three main grid modernization programs over the Forecast Period. They are:

- AMI Infrastructure Upgrades discussed in Section 4.4.5.3.3.1;
- Continued Voltage Conversion work discussed in Section 4.4.5.3.6 and;
- Continued installation of Distribution Automation schemes discussed in Section 4.4.5.4.2.

Across these three major modernization activities Entegrus expects to improve the connection capacity, operating efficiency and responsiveness, information security, and weather resiliency of its distribution grid. All other System Access, System Renewal, and System Service investments will be planned and constructed to modern utility standards, to improve consistency and cost efficiency of Entegrus' asset base and the operations supporting it.

Aside from the larger investment programs, Entegrus will also continue removing the remaining technologically outdated assets from operation, such as porcelain insulators, Poletrans transformers and small-diameter copper wire.

4.2.4 REG Accommodation

As noted in Section 4.2.1 there are currently no new projects in Entegrus' generation / non-load connection queue aside from two storage projects where connection capacity has been confirmed and CCRAs have been issued. Aside from these two projects, Entegrus is not aware of any future interconnection interest from generation or storage proponents. Accordingly, it does not anticipate renewable generation accommodation to drive any system developments over the next five years.

4.2.5 Climate Change Adaptation

There are no programs in the 2021-2025 DSP with climate change adaptation as a formal primary or secondary driver. However, Entegrus expects the outcomes of several programs to have positive impact on its ability to adapt to the changing climate. These include:

- *Overhead System Renewal* work, including reactive replacements and voltage conversion projects, which are set to upgrade Entegrus' aged overhead assets to latest standards to make them more resilient to storm activities.

- *Underground System Renewal* work, which, among other activities, targets removal of the remaining submersible underground transformers that have known operating issues following significant precipitation events.

Other planned investments such as the upgrades to the Chatham operating centre's HVAC infrastructure, decommissioning of several step-down substations and regular renewal of the utility's rolling stock are not expected to make Entegrus more resilient to the changing climate, however will contribute to the reduction of its environmental footprint.

4.3 Capital Expenditure Planning Process Overview (5.4.1)

The information a distributor must provide includes points a through f included in each section below.

Capital expenditure planning process is a part of Entegrus' overall Asset Management Process, with its relative position and key components illustrated in Phase 3 of Figure 3-1. A key objective of the Capital Investment Planning Phase of the AM process is to allocate Entegrus' available financial resources across the potential investment portfolios in a manner that maximizes the value of the financial resources available for the period in question. To accomplish this objective, Entegrus relies on the combination of bottom-up planning by subject matter experts that utilize the insights from the earlier Phases of the AM process, and the top-down expenditure constraints set by its Executive and approved by its Board of Directors.

The process consists of three fundamental components, each of which considers planning decisions at an increasingly granular level:

- Allocating Capital and O&M Resources;
- Exploring Alternatives; and
- Optimizing for Execution.

The end goal of the Capital Expenditure Planning process is to develop a detailed one-year capital and O&M budget for the utility to execute in the immediate term, along with a four-year planning outlook to track and progressively refine the anticipated investment priorities.

4.3.1 Prioritization and Additional Exploration of Alternatives (5.4.1a)

A detailed description of the analytical tools and methods used for risk management and its correlation to the capital expenditure plan. A distributor is responsible for managing its business risk in a manner to achieve its objectives through a comprehensive risk portfolio. These risks could include, but not limited to, system reliability, cyber-security, and climate change adaptation.

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, Entegrus 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. Other alternatives that Entegrus planners consider depend on a type of an asset undergoing intervention, the party performing the work, the length and materiality of an underlying investment, and others.

Where relevant, Entegrus asset managers explore alternatives at two distinct levels of consideration:

- 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.

Alternative considerations that apply across various types of investment programs and projects include the following:

- *Intervention Type Alternatives* – applicable where an identified need can be satisfied in a variety of ways, such as preventative maintenance, component refurbishment, replacement, or changes in the utilization of an asset (e.g. load transfers to avoid/defer the need for station asset upgrades).

- *Scope Alternatives* – applicable in the context of planned System Renewal activities such as Voltage Conversion where a different number of neighbouring assets could be replaced, or certain types of IT investments, where different options as to the scope of hardware and/or software upgrade or replacement work are possible.

- *Vendor Alternatives* – certain types of potential capital investments or maintenance work can be delivered by a variety of different vendors, and/or may involve in-house staff or third-party contractors more generally.

- *Location Alternatives* – primarily relevant for System Renewal work where groups of deteriorated assets posing similar risks may be located throughout the system, or certain types of System Service work such as Distribution Automation (DA) equipment that could be deployed in a variety of geographical locations.

- *Technology or Material Alternatives* – considerations involving a specific type of materials and/or equipment to address the identified asset intervention needs, such as use of different types of wood, installation of overhead vs. underground service for a new residential subdivision or addressing the near-term impact of outages caused by defective equipment through installation of DA equipment.

- *Capacity Alternatives* – the size/volume of capacity upgrade beyond the level required by the immediate needs that drive the upgrade requirement.

In exploring alternatives within or across individual candidate projects, Entegrus staff rely on the analytical insights from the prior stages of the AM Process, to determine the mix of investments and their mode of execution that addresses the greatest number of known risks, ensures compliance with internal and external policies and positions Entegrus for longer-term success. Depending on the type of investments, there are different planning assumptions

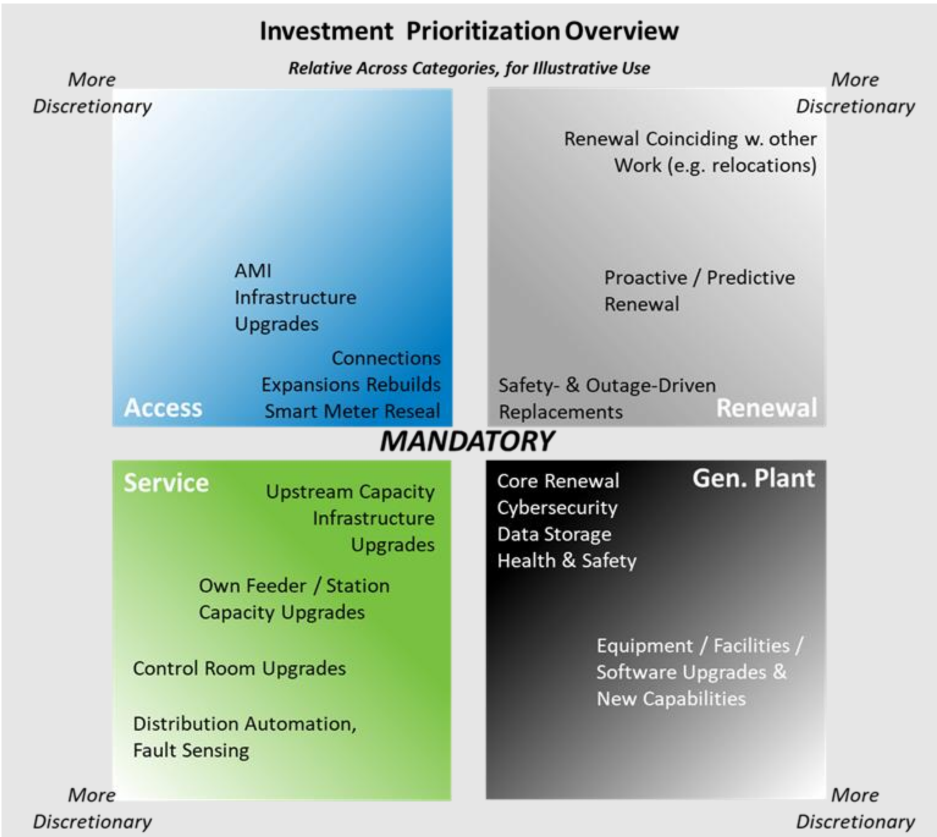
While they are formally considered at the time of Capital Expenditure Planning work, Entegrus staff may explore intervention alternatives at different junctures of the Asset Management process. While certain alternatives decisions are explored and formalized on the level of departmental or utility-wide policy (e.g. in-sourcing vs. outsourcing), others may be made on the basis of procurement or workforce deployment economics in a given year and/or for a given set of projects or programs. Other types of alternatives are considered on a project-by-project level at the scoping, design, procurement or even construction stage.

4.3.1.1 Planning Objectives and Assumptions and Criteria

Cross-Portfolio Prioritization Assumptions

Figure 4-2 displays an overview of Entegrus' default assumptions for prioritization across investments (subject to more specific analytical inputs as available and relevant). Mandatory projects (displayed closer to the centre of the figure below) are automatically selected and prioritized based on externally driven schedules and needs. From the four major investment categories, *System Access* is almost exclusively made up of the non-discretionary work, the scope and timing of which is dictated by the requests from the third parties and the conditions of the utility's distribution license.

Figure 4-2: Investment Prioritization Default Assumptions



The *System Service* category projects that are associated with increasing feeder or upstream station capacity or infrastructure to enable load growth are mandatory in nature, with some degree of discretion available in terms of the exact timing of commencing the projects, sizing of the upgrades and their geographical location and electrical configuration. Entegrus planners explore these options through an integrative analysis of all available data (including the feedback from relevant third parties and the upstream utility) and make prioritization decisions on balance of these considerations.

Other types of *System Service* investments, such as Distribution Automation ("DA") are more discretionary in nature, and their scope, timing and locations are a function of engineering and economic cost/benefit analysis. These projects are prioritized on the basis of their estimated value proposition, along with other discretionary projects and programs.

Aside from the projects that seek to address known employee and public safety risks or liquidate the in-service failures, Entegrus has historically considered its *System Renewal* projects to be generally discretionary. In selecting among the potential System Renewal projects, asset managers estimate the number of reactive failures, and then allocates the remainder of the available budget among planned projects using the results of risk-based asset intervention analysis, as described in Section 3.3.2. It is important to note, that while the use of risk-based analytics enable Entegrus to assess the available data in an objective manner, Entegrus always integrates the expert assessment of its engineering staff.

Finally, the bulk of Entegrus' annual *General Plant* investment levels are governed by formal asset lifecycle management policies described in Sections 3.3.3 through 3.3.5. As such, they are generally treated as non-discretionary. However, where possible certain types of General Plant investments such as HVAC and pavement renewal can be paced and prioritized from time to time depending on other emerging needs, and the internal and/or external experts' assessments of the feasibility of deferral.

Corporate Planning Objectives

Where specific cost-benefit analysis or other available objective information may not yield definitive prioritization results, or where additional evaluation criteria are seen as beneficial, Entegrus planners may refer to the scoring scheme inherent in the utility's Corporate Planning Objectives, as showcased in the Figure 4-3. The Corporate Planning Objectives framework may also be used to support the deliberations of Entegrus' Executive Leadership Team – as a reference point while deciding on budgetary allocations across the four major investment portfolios.

The Corporate Planning Objectives are a key means in which Entegrus continues to articulate its Asset Management Strategy and gauge strategic fit of specific undertakings. However, in preparing this DSP, Entegrus relied on the scoring framework associated with the Planning Objectives to a comparatively lesser degree than in the Plan's last iteration. This shift is largely because of the enhancements to its risk-based planning approaches and formalization of its asset lifecycle management policies over the Historical Period. Nevertheless, the framework remains an important reference available to Entegrus planners and the Executive Team in situations where it deems important to supplement the *prediction of value* made by quantitative analysis tools with expert *judgment* made by human professionals.

Figure 4-3: Corporate Planning Objectives & Scoring Framework

Entegrus Planning Objectives & Scoring Framework

Objectives \ Scores	1	2	3	4	5
Public Safety	*Project does not focus on Public Safety (e.g. most General Plant).*	*Minor ancillary Public Safety benefits (e.g. System Service).*	*Public Safety is a secondary driver (e.g. Voltage Conversion).*	*Reactive Replacements & System Access work that prevents Safety risks.*	*Projects specifically addressing a Public Safety Concern.*
Employee Safety	*Project does not focus on Employee Safety (e.g. 3rd Party Requests).*	*Minor ancillary Employee Safety benefits (e.g. System Service).*	*Employee Safety is a secondary driver (e.g. System Access, Voltage Conversion).*	*Reactive Replacements & System Access work that prevents Safety risks.*	*Projects specifically addressing Employee Safety Concerns.*
Environment	*Project does not improve or correct Environmental Concerns.*	*Minor ancillary benefits for the Environment (e.g. System Service).*	*Environment is a secondary driver (e.g. Voltage Conversion, FIT Support).*	*Reactive Replacements & Engineering Work that prevents Enviro risks*	*Project specifically mitigates a known Environmental Hazard*
Reliability	*Project does not affect Reliability in a meaningful way.*	*Minor ancillary Reliability benefits (e.g. General Plant).*	*Support future Reliability of assets specifically being worked on (System Access).*	*Voltage Conversions FIT Related System Service*	*Directly Targets Reliability issue: (Replacements, Automation, SCADA).*
Operational Efficiency	*Does not consider Operational Efficiency (e.g. Emergencies).*	*Adds new Efficiently Designed & Constructed Assets (e.g. System Access)*	*Efficiency is a material, but a secondary driver (e.g. System Renewal).*	*System Service work with benefits that advance Operational Efficiency*	*Technology or reconfiguration work that improves Operating Efficiency.*
Cost Effectiveness	*Low-cost alternative is not a consideration (e.g. Emergencies).*	*Work with limited ability to manage costs (e.g. upstream System Service)*	*Cost a material factor in design or technology choice, but not a main driver.*	*Cost savings are a major consideration.*	*Project specifically chosen as the lowest cost solution.*

Optimizing for Execution

This step entails the preparatory activities that define the details of specific work execution activities. For different types of work these may involve some of the following activities:

- Electrical and civil assets design utilizing CAD software and referencing the GIS Asset Registry or the CYME software for load flow simulation;
- Detailed labour, materials and equipment unit cost estimation using the Asset Assemblies cost database described in Section 2.1.6.4;
- Materials ordering, procurement and work site staging, coordination of rentals of special equipment and/or performing requisite site prep (e.g. vegetation, hydrovac, disposal);
- Identification of potentially available location- or asset-specific work execution synergies with activities planned by other functional areas;
- Outage planning and coordination;
- Procurement tender preparation, administration, and negotiations;
- Permitting, licensing and/or other forms of relevant approvals;

- Cost recovery agreements with requesting customers or relevant third parties;
- Other pre-execution preparation activities as appropriate.

Overall, the fundamental goal of this part of the AM Process is to facilitate safe, efficient, and minimally disruptive work execution by Entegrus' staff and contactors.

4.3.1.2 Technical Planning Criteria

In conducting its pre-execution preparatory activities, Entegrus follows well-defined technical standards to maintain safety and drive efficiency of its operations. The following Table 4-15 provides a brief overview and summary of some of the key planning criteria that Entegrus planners apply to their planning, design and procurement work.

Table 4-15: Technical Planning Criteria Summary

Criteria	Planning Guideline
General Planning Assumptions	In planning of the system, "good utility practice" is be followed, using decisions that are increasingly based on objective asset data collected from the field, and analytical approaches developed in-house or co-developed with industry partners. Where own asset data may be insufficient to undertake desired analysis, industry data may be used as a proxy, provided that final planning decisions are approved by in-house experts on balance of data insights and local expertise.
System Voltages	The primary supply voltage for Entegrus' service area is 27.6 kV, supplied from Hydro One's transmission and distribution stations and feeders. All legacy lower-voltage feeders below 27.6 kV are to be gradually converted to the standard voltage having regard for condition and criticality of feeder assets and those of the upstream distribution stations. All conversion work is to be executed to the Utilities Standards Forum ("USF") Standard Design.
Distribution Substations	Distribution Substations ("DS") will be gradually decommissioned as the surrounding low-voltage feeders are converted to standard primary voltage. It is Entegrus' intent to avoid incurring any major replacement costs associated with substation equipment. Accordingly, the timing of feeder voltage conversions in specific areas will have regard for the age and condition of the substations in question. Where practicable, Entegrus will avoid connecting new customers in the General Service category and above to the low-voltage feeders emanating from its distribution substations.
Feeder Operation	Current unbalance is defined as the maximum phase current deviation from the average phase current, as a percentage of the average phase current. Feeders with a phase current deviation in excess of 20% from average will be considered for rebalancing. New single-phase load additions should be connected to the phase with the least connected KVA, if it is available, to maintain a balanced circuit. Under normal and contingency situations, circuit voltage drop shall be managed such that customer service voltages shall comply with the standards of the Canadian Standards Association, CSA Standard CAN3-C235 (latest edition).

Criteria	Planning Guideline
	Losses on three phase feeders should be kept to a minimum using appropriately sized conductor, optimal feeder loading and load sharing, phase balancing, and in some cases, applications of shunt capacitors. Currently, the industry standard for a typical urban utility is in the range of 2.5 -3.5%.
Undergrounding	System Renewal work will typically proceed on a like-for-like basis with respect to Overhead and Underground infrastructure. Undergrounding of existing overhead assets may be considered where there are external cost recovery mechanisms, or where municipal zoning or other constraints make overhead service infeasible.
Distribution Poles	Entegrus will replace all existing steel and concrete poles with wood equivalents as the incumbent units reach their ends of life. Replacement for other types of poles will only be considered where specifically requested by a customer and cost recovery of the difference between the default standard and the customer's request is executed.
Planning Horizon	The planning horizon shall be 5 years to align with the OEB DSP requirements, unless Regional Planning work or strategic planning activities mandate consideration of investments over a longer horizon.
Distribution Automation	Distribution automation through remote switching and automatic reclosing is to be provided, when cost justified, to ensure that load lost during single contingencies can be restored in a minimum amount of time. Distribution automation should also be considered during plant rebuild and new construction as an alternative to manual operated switches.
Distribution Transformers	Distribution transformers with a normal residential load profile can be loaded up to a maximum peak of 150% of nominal rating. For other loads, 130% of nominal rating.
Rolling Stock Renewal	Replacement of vehicles and other mobile implements shall be conducted in accordance with the internal Fleet Replacement Policy (See Section 3.3.5).
IT Systems and Infrastructure	Procurement of new IT systems shall opt for commercial off the shelf solutions with a focus on configuration and implementation support / change management rather than customization. Cyber security shall be a major priority in IT procurement and deployment. Hyper-Converged Infrastructure shall be the preferred approach to core IT infrastructure renewal and expansion (See Section 3.3.3).

4.3.1.3 Outlook and Objectives for Accommodating REG

With no renewable generation projects in its current connection queue, Entegrus does not anticipate that accommodation of renewable generation will be a factor in its capital planning decision-making over the Forecast Period. The table below provides an overview of connection capacity limitations on Hydro One's facilities upstream of the Entegrus system as of June 9, 2020.

Table 4-16: REG Connection Capacity Limitations

Station	Connected REG (kW)	Projects awaiting connection (kW)	Station Thermal Capacity (MW)	Short Circuit Capacity (MVA)	Average Demand (kVA)	Available Capacity (kW) As of June 9, 2020	Limitation Source
Centralia TS	102.4	-	29.4	29.4	2,610.0	397.6	Minimum Feeder Load
Duart TS DESN 1, Bus B	488.0	-	50.0	84.0	1,952.0	12.0	Minimum Feeder Load
Duart TS DESN 1, Bus Y				82.0			
Edgeware TS Bus B	2,979.6	-	13.6	163.9	56,700.0	7,020.4	-
Edgeware TS Bus Y			20.1	164.9			
Kent TS DESN 1, Bus B	3,614.3	-	62.2	134.0	103,980.0	2,835.7	Station Bus
Kent TS DESN 1, Bus Y				134.0			
Kent TS DESN2			32.8	135.0			
Leamington TS, Bus Y	409.5	-	41.5	163.0	1,825.0	-	Minimum Feeder Load
Longwood TS	72.2	-	48.5	169.0	6,160.0	2,427.8	Minimum Feeder Load
Strathroy TS	2,362.6	-	34.3	132.0	30,500.0	3,637.3	Minimum Feeder Load
Tilbury West DS T1	1,686.4	-	17.2	239.0	15,400.0	593.6	Minimum Feeder Load
Tilbury West DS T2				238.0			
Wallaceburg TS	2,398.1	-	35.8	138.5	25,180.0	3,101.9	Minimum Feeder Load

4.3.2 Processes, Tools, and Methods (5.4.1b)

A description of the process(es), tools and methods (including relevant linkages to the distributor's asset management process) used to identify, select, prioritize and pace the execution of projects/programs in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills).

The processes tools and methods to identify, pace and prioritize among the projects and programs considered for inclusion into Entegrus' Capital Expenditure Plan are described in detail across numerous sections in Sections 2, 3 and in other parts of Section 4. Among others, please refer to Sections 2.1.6, 3.1, 3.3, and 4.3.1.

4.3.3 REG Investment Prioritization (5.4.1c)

If different from that described above, the method and criteria used to prioritize REG investments in accordance with the planned development of the system, including the impact, if any, of the distributor's plans to connect distributor-owned renewable generation project(s).

Entegrus does not anticipate the need to make any investments in new assets required to accommodate REG sources. Accordingly, it does not have a separate process for prioritizing potential REG-enabling investments either amongst themselves, or relative to other system investments. Should a situation requiring such prioritization arise, Entegrus will guide its decision-making in accordance with the generation connection provisions of the Distribution System Code ("DSC").

4.3.4 Non-Distribution System Alternatives to Relieving System Capacity (5.4.1d)

The distributor's approach to assessing non-distribution system alternatives to relieving system capacity or operational constraints, including the role of Regional Planning Processes in identifying and assessing alternatives.

As a member of four different Regional Planning groups, Entegrus participates in exploration of non-wires solutions on the regional and bulk levels to the extent that these solutions may impact its system and/or trigger cost responsibility. As of the submission of this Plan, Entegrus is unaware of any such projects.

Moreover, and as evidenced from the discussion of its efforts to a subsequently cancelled connection of a large agricultural processing facility in 2019, and its exploratory study with Hydro One as a result of the recommendations from the Chatham/Lambton/Sarnia Regional Planning study, Entegrus always explores opportunities to relieve upstream capacity expansion needs by way of reconfiguration of its system downstream of the constraint – by way of load transfers, changes to protection schemes, etc.

Finally, in performing load forecasts (which ultimately drive its planning for System Service investments to relieve connection capacity constraints), Entegrus accounts for the impact of Conservation and Demand Management ("CDM") programs, REG sources and energy storage currently in place and/or anticipated to be in place over the forecasting horizon. In taking the above steps, Entegrus accounts for the non-distribution alternatives to capacity investments within its own service territory or in relation to local upstream enhancements to Hydro One's assets.

4.3.5 System Modernization (5.4.1e)

A distributor's strategy in taking advantage of opportunities that arise during system planning to implement cost-effective modernization of the distribution system such that it becomes more efficient, reliable, and provide more customer choice. This could include, but not limited to, the following: The options a distributor has considered for facilitating customer access to consumption data in an electronic format; The mechanisms that facilitate real-time data access and behind the meter services and applications that a distributor has considered for the purpose of providing customers with the ability to make decisions about their electricity costs; The investments necessary to facilitate the integration of distributed generation, distributed energy resources and more complex loads (e.g., customers with self-generation and/or storage capability); The technology-enabling opportunities a distributor has considered to increase operational efficiencies, improve asset management or enhance services to customers; The distributor's adoption of innovative processes, services, business models, and technologies.

System modernization is a significant outcome of a number of Entegrus' planned investment programs – most notably the Voltage Conversion work and Distribution Automation investments. However, modernization in and of itself is not a primary planning driver for the utility. System modernization investments require a variety of internal and external collaboration to ensure projects delivered increase operational efficiencies and improve customer experience. Given the dispersed nature of Entegrus' service territory and significant travel distances between communities, automation deployments often target remote communities that suffer from loss of supply. However, deployments by no means are limited to just the more remote communities, modernization investments are carefully considered from both customer satisfaction and cost management perspectives to maximize value of the investment.

For improvement of asset management process and enhancement to service to customers, please see Section 2.1.6.

4.3.6 Rate-Funded Activities to Defer Distribution Infrastructure (5.4.1f / 5.4.1.1)

Consideration of distribution rate funded Conservation and Demand Management (CDM) programs, that are not funded by the Global Adjustment Mechanism, to defer distribution infrastructure as described in Section 5.4.1.1.

Entegrus has not identified any use cases for rate-funded activities driven specifically by the objective of deferring construction of distribution infrastructure (e.g. Targeted Demand Response deployments with larger customers to defer connection capacity upsizing). However, among the secondary benefits of its planned Distribution System Automation investments described in Section 4.4.5.4.3 is the ability to pace the renewal of its distribution infrastructure while improving outage durations for affected customers in the interim.

4.4 Capital Expenditure Summary (5.4.2)

The purpose of the information filed under this section is to provide a snapshot of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Despite the multi-purpose character a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or trigger) driver of the investment. For material projects/programs, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or program for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Entegrus' DSP details the system investment program grounded in the decisions made in the course of Entegrus' Asset Management and Capital Expenditure Planning processes. Entegrus has grouped functionally similar investment undertakings targeting the same types of outcomes into Programs. Accordingly, this DSP substantiates the scope and nature of Entegrus' planned investment portfolio allocations on a program level, dedicating comparatively more effort to justification of programs where the utility has a greater degree of spending discretion. In addition to the Program-level narratives, individual project narratives for planned Year 1 (2021) projects that exceed the materiality threshold of $130,000 are available in Attachment O.

Entegrus developed a materiality threshold of $130,000 based on it 2019 Distribution Service Revenue as recorded in Account 4080 of $26M multiplied by the OEB standard 0.5% threshold.

This Plan includes information on prospective investments spanning a five-year Forecast Period, as well as the outcomes of the past investments over the 2016-2020 projects over the Predecessor and Combined Historical Periods.

The Capital Expenditure Summary provides a 'snapshot' of Entegrus' capital expenditures over a 10-year period, which includes five historical years and five forecast years. The costs of individual projects or activities are allocated to one of four investment categories based on the primary (i.e. initial or 'trigger') driver of the investment, assigned based on examples provided in the OEB's Chapter 5 guidance.

4.4.1 DSP Project Mapping

In order to facilitate reporting, Entegrus has aligned the previously approved Historical Period projects into the same Projects that are proposed for this DSP's Forecast Period. This allowed for enhanced alignment between reporting periods as well as alignment between Legacy Entegrus' 2016 DSP and the former STEI's 2015 DSP. The Table below shows the mapping from the original DSP Projects to the 2021 DSP Project names. Additionally, Entegrus has recategorized Engineering Support Capital from System Renewal in its 2016 DSP to System Access in its 2021 DSP due to the significant role this capital plays into the design of System Access projects.

Table 4-17: Legacy Entegrus Project Mapping ($000's)

2021 DSP Project Name	2016 DSP Project Name	2016	2017	2018	2019	2020
System Access						
Commercial and Industrial Rebuild	Commercial Industrial Rebuild	$264	$266	$269	$272	$274
Contributed Capital	Contributed Capital	-$375	-$375	-$375	-$375	-$375
Customer Connections: Commercial & Industrial	Commercial Industrial New	$128	$129	$131	$132	$133
Customer Connections: Residential & Subdivision	Residential Detached	$177	$179	$180	$182	$184
	Residential New	$138	$139	$141	$142	$143
	Residential Rebuilds	$126	$128	$129	$130	$131
Engineering Support Capital	Engineering Support	$600	$609	$618	$628	$637
Miscellaneous System Access	Account Cancellation	$16	$16	$16	$17	$17
	Capital Expansion Requests	$127	$128	$129	$130	$131
	FIT Cost	$163	$164	$166	$168	$169
	Load Transfers	$50	$0	$0	$0	$0
Total		**$1,413**	**$1,383**	**$1,404**	**$1,425**	**$1,446**
System Renewal						
Critical Defect Replacements	Replacements - Insulator	$10	$0	$0	$0	$0
	Replacements - LIS	$85	$85	$90	$90	$75
	Replacements - Primary Cable	$350	$300	$310	$310	$320
	Replacements - Step Down Transformer:	$100	$0	$0	$0	$0
	Replacements - Switchgear	$0	$15	$0	$15	$0
Emergency Response	Emergencies	$230	$230	$230	$230	$230
Metering Renewal	Replacements - Retail Meters	$420	$429	$307	$313	$319
Operation Support Capital	Operations Support	$673	$683	$694	$705	$716
Pole Replacement	Replacements - Poles	$135	$135	$135	$137	$137
Transformer Replacement	Replacements - Transformers	$222	$225	$228	$232	$232
Voltage Conversion	Conversions - Blenheim	$0	$0	$50	$150	$250
	Conversions - CK Substation 1	$0	$0	$0	$0	$75
	Conversions - CK Substation 3	$200	$200	$200	$200	$15
	Conversions - CK Substation 4	$0	$50	$300	$300	$150
	Conversions - CK Substation 6	$300	$250	$350	$200	$0
	Conversions - Feeder 5 Parkhill	$0	$50	$250	$250	$250
	Conversions - Mount Brydges	$0	$0	$50	$300	$300
	Conversions - MP Substation 1	$250	$250	$0	$0	$0
	Conversions - MP Substation 3	$200	$200	$200	$200	$200
	Conversions - MP Substation 4	$250	$250	$250	$250	$250
	Conversions - Ridgetown	$50	$100	$250	$250	$250
	Conversions - Wheatley	$240	$400	$260	$0	$0
Miscellaneous System Renewal	OPEB Adjustment	$35	$0	$0	$0	$0
Total		**$3,749**	**$3,852**	**$4,154**	**$4,131**	**$3,769**
System Service						
System Automation	System Automation	$425	$475	$400	$400	$425
System Modernization and Planning	Asset Management	$50	$50	$50	$50	$50
	Control Room Support	$101	$102	$102	$103	$103
	Enhanced System Monitoring & Sensing	$250	$300	$200	$200	$225
	GIS	$260	$210	$215	$220	$225
	SCADA	$107	$108	$109	$110	$113
Total		**$1,192**	**$1,244**	**$1,076**	**$1,083**	**$1,141**
General Plant						
Building	Building	$275	$275	$120	$110	$110
IT Hardware	Computers	$116	$100	$91	$88	$94
IT Software	Software	$352	$242	$227	$237	$202
Rolling Stock	Rolling Stock	$600	$490	$460	$475	$570
Tools	Tools	$156	$107	$105	$106	$110
Miscellaneous General Plant	Office Furniture	$20	$20	$20	$20	$20
Total		**$1,519**	**$1,234**	**$1,023**	**$1,036**	**$1,106**
Grand Total		**$7,874**	**$7,713**	**$7,657**	**$7,675**	**$7,461**

Below is a summary of the former STEI's 2015 DSP projects mapped to the proposed 2021 DSP Projects. Entegrus notes, STEI's 2015 DSP only included projects until 2019. For the purposes of analysis, Entegrus has used the 2019 planned project amounts as placeholders for 2020.

Table 4-18: Former STEI's Project Mapping ($000's)

2021 DSP Project Name	2015 DSP Project Name	2016	2017	2018	2019	2020
System Access						
Contributed Capital	Contributed Capital	-$100	-$100	-$100	-$100	-$100
Customer Connections: Residential & Subdivisioı	New Subdividion - Misc.	$200	$200	$200	$200	$200
Total		**$100**	**$100**	**$100**	**$100**	**$100**
System Renewal						
Voltage Conversion	Conversions - Aldborough/Airey/Vanier	$0	$0	$0	$562	$562
	Conversions - Aldborough/Pullen/Sparta/Parish	$0	$0	$0	$487	$487
	Conversions - Applewood/Lawrence/Butler/Dryer	$0	$0	$700	$0	$0
	Conversions - Balaclava/S. Edgeware	$0	$303	$0	$0	$0
	Conversions - Confederation/Lakeview/Stirling	$0	$0	$0	$0	$0
	Conversions - Edward/Gaylord/Elgin Mall	$0	$0	$230	$0	$0
	Conversions - Fairview/Sinclair/Talbot	$0	$0	$0	$0	$0
	Conversions - First/Thompson/Glanworth/Ashton	$0	$0	$0	$512	$512
	Conversions - Hammond/Patricia/Inkerman/Daniel	$790	$0	$0	$0	$0
	Conversions - Highview/Aspen/Chestnut/Croatia/Pc	$800	$0	$0	$0	$0
	Conversions - Locke/Rosemount	$0	$0	$0	$0	$0
	Conversions - Major Line West of Sunset	$0	$0	$285	$0	$0
	Conversions - Park/Mary Bucke/Forest/First	$0	$463	$0	$0	$0
	Conversions - Paulson/Gustin/Paddon	$0	$0	$0	$0	$0
	Conversions - Tecumseh/Montcalm/Brock/Alma	$0	$763	$0	$0	$0
	New Powerline - Centennial, Talbot to Wellington	$0	$0	$305	$0	$0
Total		**$1,590**	**$1,530**	**$1,520**	**$1,560**	**$1,560**
System Service						
System Modernization and Planning	SCADA	$50	$50	$100	$100	$200
Total		**$50**	**$50**	**$100**	**$100**	**$200**
General Plant						
Building	Building, Furniture & Equipment	$175	$15	$5	$5	$5
IT Hardware	Computer Hardware	$66	$49	$60	$49	$49
IT Software	Computer Software	$66	$49	$60	$49	$49
Rolling Stock	Rolling Stock	$60	$265	$20	$0	$0
Miscellaneous General Plant	Other	$20	$30	$20	$20	$20
Total		**$386**	**$408**	**$165**	**$122**	**$122**
Grand Total		**$2,126**	**$2,088**	**$1,885**	**$1,882**	**$1,982**

Entegrus notes, the System O&M amount included in Legacy Entegrus' 2016 DSP Plan amounts was reported on a Total O&M basis which included Billing & Collecting and Administrative expenses in addition to System O&M. Table 4-19 below shows the details by each O&M category to reconcile to the original O&M amount included. The tables and analysis below have been updated to reflect only System O&M in the Plan and Actual amounts.

Table 4-19: Legacy Entegrus 2016 DSP Approved O&M Plan ($000's)

Line No.	Description	2016	2017	2018	2019	2020
1	Operating and Maintenance	$3,055	$3,043	$3,095	$3,153	$3,207
2	Billing & Collecting	$2,476	$2,466	$2,508	$2,556	$2,599
3	Community Relations	$238	$237	$241	$245	$250
4	Administration	$3,726	$3,711	$3,776	$3,849	$3,915
5	**Total**	**$9,496**	**$9,458**	**$9,621**	**$9,803**	**$9,971**

4.4.2 Capital Expenditure Summary, Appendix 2-AB

The distributor must provide the information described in Chapter 2, Appendix 2-AB. Appendix 2-AB illustrates how information filed under this section 5.4.2 includes a distributor's actual and forecast (i.e. proposed) capital expenditures and capital contributions over the historical and forecast periods. At a minimum, for historical years, applicants that have previously filed a DSP must provide the actual total expenditures in each DSP category. All years must be provided per the Chapter 5 investment categories. Plan expenditures over the historical period refer to a distributor's previous plan for capital expenditures filed in its last rebasing application, after adjustments (if any) resulting from the OEB's decision. If no previous plan has been filed, applicants are only required to enter their planned total capital budget in the plan column for each historical year and for the bridge year including the OEB-approved amount for the last rebasing year.

Table 4-20: Appendix 2-AB

Line No.	Description	2021	2022	2023	2024	2025
1	System Access	$5,867	$4,308	$6,010	$3,909	$3,926
2	System Renewal	$7,238	$7,669	$7,872	$9,380	$9,395
3	System Service	$1,063	$968	$987	$1,944	$1,519
4	General Plant	$1,974	$2,051	$2,088	$2,121	$2,150
5	**Total Expenditure**	**$16,142**	**$14,996**	**$16,957**	**$17,355**	**$16,991**
6	Capital Contributions	-$3,367	-$2,300	-$2,356	-$2,413	-$2,471
7	**Net Capital Expenditures**	**$12,775**	**$12,696**	**$14,601**	**$14,942**	**$14,520**

4.4.3 O&M Impacts

System O&M costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. A distributor is expected to consider the reduction in O&M costs when planning capital projects. A description of the impacts of capital expenditures on O&M must be given for each year or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital program.

This initial stage of the capital expenditure planning process is the point of intersection between Entegrus' ongoing AM work and the strategic guidance from the company's Executive that sets out the expenditure targets for the upcoming years.

This Capital and OM&A Resource Allocation stage therefore acts as a key threshold, which is at once *informed* by the outcomes of the earlier asset intervention planning work and *informs* the more detailed asset intervention planning work that follows.

A detailed description of the analytical tools and methods used for risk management and its correlation to the capital expenditure plan is covered in Section 3.3.2. These analyses are validated by expert knowledge of the system to ensure that all specific risks (e.g. system reliability, equipment obsolescence, Health & Safety, cyber security, climate change, etc.), are appropriately considered by the analytic tools.

This occurs as the annual spending targets suggested by the Executive and informed by the prior year business plan, overall strategy, corporate planning objectives and past year expenditure levels are gradually transformed into detailed budgets and forecasts.

Budget Formulation and Allocation Process

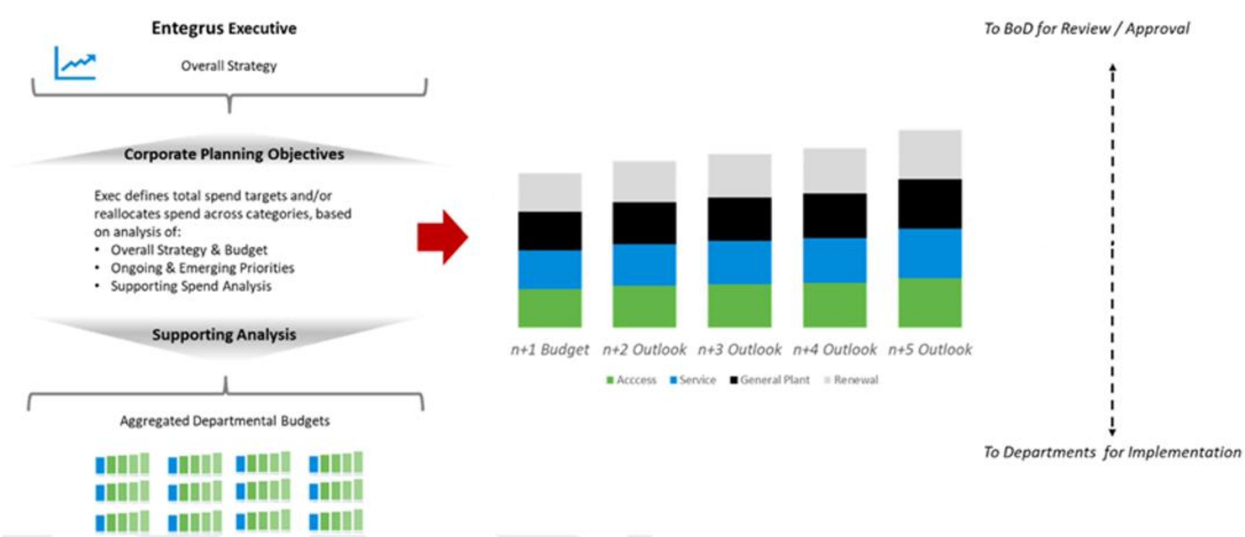
The capital and OM&A allocation work proceeds in the following manner:

1. Entegrus subject matter experts develop detailed departmental budgets for the upcoming year during the summer of the prior year. In preparing these budgets, their starting point is the forecast they provided in the previous year's budgeting exercise (when the year that is now subjected to detailed budgeting was an "outlook" for two years ahead).

2. The last year's forecast is reviewed at the departmental level against the new insights derived through the Asset Management process, including the emergence of additional failure risks, incremental capacity requirements, new connection applications, or any other new information that may warrant making material adjustments to the previously developed forecast.

3. As the "n+2" year Outlook gets refined into a more detailed "n+1" Budget, departmental leaders also review and adjust as necessary their outlooks for the following three years and develop a new forecast for the fourth outlook year ("n+5"). In this manner, every successive planning year generates a one-year draft departmental budget ("n+1") and a four-year outlook ("n+2" through "n+5"). The figure below captures the process flow of the first three steps.

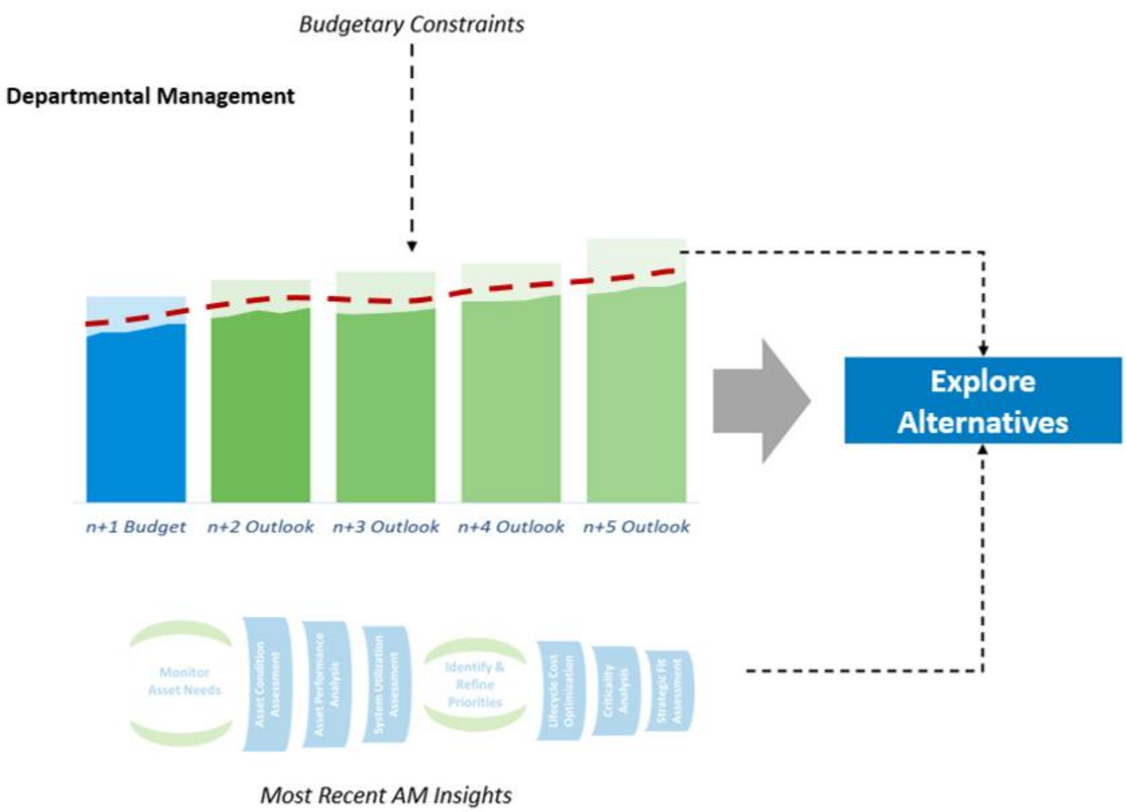
Figure 4-4: Schematic of Entegrus Budgetary Process



Having incorporated their latest insights into their budgets and outlooks, departmental leaders submit their latest estimates for aggregation to the Planning department, where the budgets are aggregated and assigned into System Access, System Service, System Renewal and General Plant categories. While supporting analysis regarding the trending, drivers of any material changes and justifications of each budget takes place at this stage, the Planning Department does not itself administer any budgetary allocations.

4. The Executive Leadership Team reviews the five-year Budget and Outlook package assembled by the Planning Department and compares the aggregate figure developed "bottom up" by departments with the "top-down" enterprise-level expenditure trajectory for the upcoming year. As required, the Executive will explore the drivers of the difference between the bottom-up budgets and the overall budgetary targets by looking at changes in assumptions and planning criteria across all four capital expenditure categories (below).

Figure 4-5: Setting of Overall Budget and Outlook



5. Along with the more detailed exploration of the upcoming year's ("n+1") Budget, the Executive reviews the revised Outlook for the following four years as well, noting material changes from previous iterations. Based on its review of the planning package relative to the utility's Planning Objectives, the Executive mandates adjustments to the upcoming year's Budget across all four categories.

6. The utility's Executive then presents a five-year Budget and Outlook to the Entegrus Board of Entegrus in the fall, where it is reviewed and approved. Should the Board of Directors review result in material revisions to the expenditure forecasts, the Executive communicates these

changes to the departmental leads and provides the guidance as to the nature and magnitude of required adjustments.

7. While the above process concerns capital investments, Entegrus seeks to avoid any incremental increases to the OM&A expenditures. To this end, a default expectation of OM&A budgets is to track inflation year-over-year. Where step changes may be warranted, they require rigorous justification and are considered on a case-by-case basis.

8. Having received any applicable top-down feedback regarding annual expenditure / budget constraints, Entegrus' departmental managers proceed to adjustment their specific investment envelopes by prioritizing and pacing their originally budgeted for program and project expenditure to arrive at the level of funding approved by the Executive.

9. 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 individual time-, location-, and activity-specific projects and programs. This is the beginning of the second stage of the Capital Expenditure Planning process – Exploring the Alternatives.

4.4.4 Historical Period Plan vs. Actual

Explanations should be provided if there are material changes in the percentage a given investment category is of the total investment over the forecast period relative to actual spending over the historical period. In addition to the Plan vs. Actual variances for individual investment categories, explanations must be provided for the following:

• Plan vs. Actual variances for the total plan for each year of the historical period

• Variances in a given investment category that are trending much higher or lower over the historical period

4.4.4.1 Overview

Table 4-21 below, show the results for the 2016 and 2017 Historical Period for both Legacy Entegrus and the former STEI. Entegrus notes that it is providing STEI's pre-amalgamation results on a best-efforts basis, particularly in the context of expenditure mapping to investment categories and the level of detail in variance analysis. Having consulted available records and available former STEI staff with relevant knowledge, Entegrus staff used their best judgment to present STEI results with maximum transparency and consistency.

The table below shows the results for the remaining Historical Period post-amalgamation by rate zone where the data is available.

Table 4-21: 2016 and 2017 Historical Comparison ($000's)

Line No.	Description	Legacy Entegrus			STEI			Combined		
		Plan	Actual	Variance	Plan	Actual	Variance	Plan	Actual	Variance
1	**2016**									
2	System Access	$1,788	$2,157	$369	$200	$812	$612	$1,988	$2,969	$981
3	System Renewal	$3,749	$4,069	$320	$1,590	$1,554	-$36	$5,339	$5,624	$284
4	System Service	$1,192	$889	-$303	$50	$25	-$25	$1,242	$914	-$328
5	General Plant	$1,519	$1,183	-$335	$386	$162	-$224	$1,905	$1,345	-$559
6	**Total Expenditure**	**$8,249**	**$8,298**	**$50**	**$2,226**	**$2,553**	**$327**	**$10,475**	**$10,852**	**$377**
7	Capital Contributions	-$375	-$846	-$471	-$100	-$654	-$554	-$475	-$1,501	-$1,026
8	**Net Capital Expenditures**	**$7,874**	**$7,452**	**-$422**	**$2,126**	**$1,899**	**-$227**	**$10,000**	**$9,351**	**-$648**
9	System O&M	$3,055	$3,030	-$26	$1,346	$1,128	-$218	$4,402	$4,158	-$244
10	**TOTAL**	**$10,929**	**$10,481**	**-$448**	**$3,472**	**$3,027**	**-$445**	**$14,401**	**$13,509**	**-$892**
11	**2017**									
12	System Access	$1,758	$2,271	$512	$200	$1,643	$1,443	$1,958	$3,914	$1,955
13	System Renewal	$3,852	$3,763	-$88	$1,530	$271	-$1,259	$5,382	$4,035	-$1,347
14	System Service	$1,244	$1,643	$399	$50	$24	-$26	$1,294	$1,667	$373
15	General Plant	$1,234	$1,826	$592	$408	$322	-$86	$1,642	$2,148	$507
16	**Total Expenditure**	**$8,088**	**$9,503**	**$1,415**	**$2,188**	**$2,261**	**$73**	**$10,276**	**$11,764**	**$1,488**
17	Capital Contributions	-$375	-$549	-$174	-$100	-$1,395	-$1,295	-$475	-$1,944	-$1,469
18	**Net Capital Expenditures**	**$7,713**	**$8,954**	**$1,241**	**$2,088**	**$866**	**-$1,222**	**$9,801**	**$9,820**	**$19**
19	System O&M	$3,043	$2,918	-$125	$1,375	$998	-$376	$4,418	$3,916	-$502
20	**TOTAL**	**$10,756**	**$11,872**	**$1,116**	**$3,463**	**$1,864**	**-$1,599**	**$14,219**	**$13,736**	**-$482**

Table 4-22: 2018-2020 Historical Period Comparison ($000's)

Line No.	Description	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		Plan	Plan	Plan	Actual	Variance
1	**2018**					
2	System Access	$1,779	$200	$1,979	$4,169	$2,190
3	System Renewal	$4,154	$1,520	$5,674	$4,518	-$1,156
4	System Service	$1,076	$100	$1,176	$1,213	$37
5	General Plant	$1,023	$165	$1,188	$1,973	$786
6	**Total Expenditure**	**$8,032**	**$1,985**	**$10,017**	**$11,874**	**$1,857**
7	Capital Contributions	-$375	-$100	-$475	-$1,454	-$979
8	**Net Capital Expenditures**	**$7,657**	**$1,885**	**$9,542**	**$10,420**	**$878**
9	System O&M	$3,095	$1,885	$4,980	$3,946	-$1,034
10	**TOTAL**	**$10,752**	**$3,770**	**$14,522**	**$14,366**	**-$156**
11	**2019**					
12	System Access	$1,800	$200	$2,000	$5,719	$3,719
13	System Renewal	$4,131	$1,560	$5,691	$4,592	-$1,099
14	System Service	$1,083	$100	$1,183	$1,223	$40
15	General Plant	$1,036	$122	$1,158	$2,383	$1,225
16	**Total Expenditure**	**$8,050**	**$1,982**	**$10,032**	**$13,917**	**$3,885**
17	Capital Contributions	-$375	-$100	-$475	-$3,357	-$2,882
18	**Net Capital Expenditures**	**$7,675**	**$1,882**	**$9,557**	**$10,559**	**$1,002**
19	System O&M	$3,153	$1,433	$4,586	$4,341	-$246
20	**TOTAL**	**$10,828**	**$3,315**	**$14,143**	**$14,900**	**$757**
21	**2020**					
22	System Access	$1,821	$200	$2,021	$6,245	$4,224
23	System Renewal	$3,769	$1,560	$5,329	$6,121	$792
24	System Service	$1,141	$100	$1,241	$1,731	$490
25	General Plant	$1,106	$122	$1,228	$1,805	$577
26	**Total Expenditure**	**$7,836**	**$1,982**	**$9,818**	**$15,902**	**$6,084**
27	Capital Contributions	-$375	-$100	-$475	-$2,726	-$2,251
28	**Net Capital Expenditures**	**$7,461**	**$1,882**	**$9,343**	**$13,176**	**$3,833**
29	System O&M	$3,207	$1,433	$4,640	$3,963	-$677
30	**TOTAL**	**$10,668**	**$3,315**	**$13,983**	**$17,139**	**$3,156**

4.4.4.2 2016 Plan vs. 2016 Actual

4.4.4.2.1 System Access

Table 4-23: 2016 System Access by Project ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance
1	Commercial and Industrial Rebuild	$264	$237	-$26	$0	$110	$110	$264	$347	$83
2	Contributed Capital	-$375	-$846	-$471	-$100	-$654	-$554	-$475	-$1,501	-$1,026
3	Customer Connections: Commercial & Industrial	$128	$122	-$6	$0	$152	$152	$128	$274	$146
4	Customer Connections: Residential & Subdivisior	$441	$737	$296	$200	$407	$207	$641	$1,144	$503
5	Delta - Wye Service Conversions	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Edgeware Capacity Enhancements	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Engineering Support Capital	$600	$649	$49	$0	$0	$0	$600	$649	$49
8	Miscellaneous System Access	$356	$411	$55	$0	$144	$144	$356	$555	$199
9	Third Party Attachments	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	**Total System Access**	**$1,413**	**$1,310**	**-$103**	**$100**	**$158**	**$58**	**$1,513**	**$1,468**	**-$45**

Legacy Entegrus' 2016 System Access investment was $103k less than Plan. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

The former STEI's 2016 System Access investment was $58k less than Plan. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

4.4.4.2.2 System Renewal

Table 4-24: 2016 System Renewal by Project ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance
1	Critical Defect Replacements	$545	$512	-$33	$0	$11	$11	$545	$524	-$21
2	Emergency Response	$230	$159	-$71	$0	$26	$26	$230	$185	-$45
3	Metering Renewal	$420	$617	$197	$0	$41	$41	$420	$658	$237
4	Miscellaneous System Renewal	$35	$0	-$35	$0	$367	$367	$35	$367	$332
5	Operation Support Capital	$673	$552	-$121	$0	$0	$0	$673	$552	-$121
6	Pole Replacement	$135	$216	$81	$0	$2	$2	$135	$217	$82
7	Transformer Replacement	$222	$335	$113	$0	$18	$18	$222	$353	$131
8	Voltage Conversion	$1,490	$1,679	$189	$1,590	$1,090	-$500	$3,080	$2,769	-$311
9	**Total System Renewal**	**$3,749**	**$4,069**	**$320**	**$1,590**	**$1,554**	**-$36**	**$5,339**	**$5,624**	**$284**

In 2016, Legacy Entegrus invested $320k over Plan in terms of System Renewal. This was primarily attributable to additional spending on Meter Renewal and Voltage Conversion, as described below.

Entegrus' Metering Renewal project is intended to replace retail meters that have reached end of life, have failed or are damaged. Legacy Entegrus maintained over 40,000 retail meters and each meter plays an integral part of the reliability of the distribution system. In 2016, Entegrus planned to invest $420k related to retail meter replacements. Legacy Entegrus was an early adopter of smart meter technology and began implementing smart meters starting in the mid-2000's. Accordingly, Legacy Entegrus increased investments in 2016 to reflect the increasing number of failures as smart meters neared end of life. Due to poor communication on some older models, manufacturer support ending on older models and meters with outdated seals and model revisions, management increased the scope of this program to ensure improved communication and reduce downtime.

Incremental spending versus Plan of $189k in Voltage Conversion relates to conversion work completed in downtown Chatham. Once the project commenced, factors became apparent that required additional civil engineering work. Once this was identified, the necessary steps were taken to ensure that safety and reliability standards were met.

The former STEI's 2016 System Renewal investment was $36k less than Plan. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

4.4.4.2.3 System Service

Table 4-25: 2016 System Service by Project ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance
1	Metering Upgrades	$0	$67	$67	$0	$0	$0	$0	$67	$67
2	Miscellaneous System Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	System Automation	$425	$346	-$79	$0	$0	$0	$425	$346	-$79
4	System Modernization and Planning	$767	$476	-$291	$50	$25	-$25	$817	$501	-$316
5	System Reinforcement	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	**Total System Service**	**$1,192**	**$889**	**-$303**	**$50**	**$25**	**-$25**	**$1,242**	**$914**	**-$328**

In 2016, Legacy Entegrus System Renewal was $328k less than Plan. This largely related to unanticipated accelerated progress on the Operational Data Store project in the prior year, which resulted in less additional investment being required in 2016.

The former STEI's 2016 System Service was $25k less than Plan. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

4.4.4.2.4 General Plant

Table 4-26: 2016 General Plant Projects ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance	2016 Plan	2016 Actual	Variance
1	Building	$275	$160	-$115	$175	$40	-$135	$450	$199	-$251
2	IT Hardware	$116	$200	$84	$66	$47	-$19	$182	$246	$65
3	IT Software	$352	$267	-$85	$66	$38	-$28	$418	$305	-$113
4	Miscellaneous General Plant	$20	$32	$12	$20	$5	-$15	$40	$38	-$2
5	Rolling Stock	$600	$285	-$315	$60	$19	-$41	$660	$305	-$355
6	Tools	$156	$238	$83	$0	$14	$14	$156	$252	$97
7	**Total General Plant**	**$1,519**	**$1,183**	**-$335**	**$386**	**$162**	**-$224**	**$1,905**	**$1,345**	**-$559**

Legacy Entegrus' 2016 General Plant investment was $335k less than Plan, due primarily to the timing of arrival of a bucket truck purchase. Manufacturing delays resulted in the bucket truck not being delivered in time for year end and the purchase was placed in service in 2017.

The former STEI's 2016 General Plant investment was $224k less than Plan, which was mostly related to its Building projects. Many of the planned building projects were deferred due to rationalization of STEI operations.

4.4.4.3 2017 Plan vs. 2017 Actual

4.4.4.3.1 System Access

Table 4-27: 2017 System Access Projects ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance
1	Commercial and Industrial Rebuild	$266	$541	$275	$0	$117	$117	$266	$659	$393
2	Contributed Capital	-$375	-$549	-$174	-$100	-$1,395	-$1,295	-$475	-$1,944	-$1,469
3	Customer Conns: Commercial & Industrial	$129	$168	$38	$0	$184	$184	$129	$352	$222
4	Customer Conns: Residential & Subdivision	$445	$502	$57	$200	$1,136	$936	$645	$1,638	$992
5	Delta - Wye Service Conversions	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Engineering Support Capital	$609	$860	$251	$0	$0	$0	$609	$860	$251
7	Miscellaneous System Access	$308	$200	-$109	$0	$206	$206	$308	$406	$97
8	Third Party Attachments	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	**Total System Access**	**$1,383**	**$1,722**	**$338**	**$100**	**$248**	**$148**	**$1,483**	**$1,970**	**$487**

For Legacy Entegrus, 2017 System Access investment was $338k less than Plan. This primarily relates to Commercial and Industrial Rebuild and Engineering Support Capital offset by increased Contributed Capital.

During 2017, Legacy Entegrus experienced higher than average Commercial and Industrial Rebuild requests. This included set up work for new or expanding commercial customers, school expansions, water treatment plant upgrades and work required by Hydro One in Dutton. This work is partially offset by the additional Contributed Capital amounts as noted above. Additionally, Legacy Entegrus added incremental engineering resourcing in 2017 to assist with planning and design for the upcoming volume of "Fibre to the Home" projects. For additional details, please see Section 4.4.4.4.1. This resulted in an increase of $251k over Plan in Engineering Support Capital in 2017.

The former STEI's 2017 System Access investment was $487k more than Plan. As discussed in Section 2.1.1.4, St. Thomas has experienced high subdivision growth, as well as expanding commercial customers. This growth resulted in an increased investment in Customer Connections: Residential & Subdivision and Customer Connections: Commercial & Industrial offset by an increase in Contributed Capital. During 2017, the former STEI commenced work on more than 8 difference residential developments. Additionally, the former STEI also commenced work to support the local hospital expansion.

4.4.4.3.2 System Renewal

Table 4-28: 2017 System Renewal Projects ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance
1	Critical Defect Replacements	$400	$114	-$286	$0	$6	$6	$400	$120	-$280
2	Emergency Response	$230	$506	$276	$0	$22	$22	$230	$528	$298
3	Metering Renewal	$429	$917	$489	$0	$70	$70	$429	$987	$558
4	Miscellaneous System Renewal	$0	$0	$0	$0	-$227	-$227	$0	-$227	-$227
5	Operation Support Capital	$683	$630	-$53	$0	$0	$0	$683	$630	-$53
6	Pole Replacement	$135	$79	-$56	$0	$31	$31	$135	$110	-$25
7	Transformer Replacement	$225	$112	-$113	$0	$44	$44	$225	$157	-$68
8	Voltage Conversion	$1,750	$1,405	-$345	$1,530	$324	-$1,206	$3,280	$1,730	-$1,550
9	**Total System Renewal**	**$3,852**	**$3,763**	**-$88**	**$1,530**	**$271**	**-$1,259**	**$5,382**	**$4,035**	**-$1,347**

Legacy Entegrus' 2017 System Renewal was $88k less than Plan. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

The former STEI's 2017 System Renewal was $1.3M less than Plan. This is largely a result of high growth in St. Thomas, which required diversion of manpower and investment to meet System Access demand, as described above. More specifically, in order to meet the higher customer connection demands in 2017, staff were not able to complete the previously planned voltage conversion work.

4.4.4.3.3 System Service

Table 4-29: 2017 System Service Projects ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance
1	Metering Upgrades	$0	$31	$31	$0	$0	$0	$0	$31	$31
2	Miscellaneous System Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	System Automation	$475	$59	-$416	$0	$0	$0	$475	$59	-$416
4	System Modernization and Planning	$769	$1,553	$784	$50	$24	-$26	$819	$1,577	$758
5	System Reinforcement	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	**Total System Service**	**$1,244**	**$1,643**	**$399**	**$50**	**$24**	**-$26**	**$1,294**	**$1,667**	**$373**

Legacy Entegrus' 2017 System Service investment exceeded Plan by $399k.

As described in Section 1.5.1, at this time a revaluation of systems and processes led to an extended system mapping project. 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.

The former STEI's 2017 System Service investment was $26k less than Plan. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

4.4.4.3.4 General Plant

Table 4-30: 2017 General Plant Projects ($000's)

Line No.	Projects	Legacy Entegrus			STEI			Combined		
		2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance	2017 Plan	2017 Actual	Variance
1	Building	$275	$138	-$137	$15	$49	$34	$290	$186	-$104
2	IT Hardware	$100	$325	$225	$49	$61	$12	$149	$386	$237
3	IT Software	$242	$425	$183	$49	$5	-$44	$291	$430	$139
4	Miscellaneous General Plant	$20	$16	-$4	$30	$1	-$29	$50	$17	-$33
5	Rolling Stock	$490	$809	$319	$265	$181	-$84	$755	$990	$235
6	Tools	$107	$113	$6	$0	$26	$26	$107	$139	$32
7	**Total General Plant**	**$1,234**	**$1,826**	**$592**	**$408**	**$322**	**-$86**	**$1,642**	**$2,148**	**$507**

In 2017, Legacy Entegrus General Plant investments exceeded Plan by $592k.

This increase was largely related to the 2016 bucket truck purchase that did not arrive in service until 2017, as discussed above in Section 4.4.4.2.4. Additionally, Entegrus invested in additional IT Hardware in preparation for the in-housing of GIS for the reasons described in Section 1.5.1, as well as the upcoming STEI amalgamation. Legacy Entegrus also experienced an increase in IT Software due to planned 2016 projects not being in service until 2017 and forced upgrade requirements due to vendors no longer supporting certain software versions utilized by Legacy Entegrus.

The former STEI's 2017 General Plant investment was $86k less than Plan. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

4.4.4.4 2018 Plan vs. 2018 Actual

4.4.4.4.1 System Access

Table 4-31: 2018 System Access Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2018 Plan	2018 Plan	2018 Plan	2018 Actual	Variance
1	Commercial and Industrial Rebuild	$269	$0	$269	$441	$172
2	Contributed Capital	-$375	-$100	-$475	-$1,454	-$979
3	Customer Connections: Commercial & Industrial	$131	$0	$131	$613	$482
4	Customer Connections: Residential & Subdivisior	$450	$200	$650	$1,818	$1,168
5	Delta - Wye Service Conversions	$0	$0	$0	$0	$0
6	Engineering Support Capital	$618	$0	$618	$666	$47
7	Miscellaneous System Access	$311	$0	$311	$342	$31
8	Third Party Attachments	$0	$0	$0	$290	$290
9	**Subtotal System Access**	**$1,404**	**$100**	**$1,504**	**$2,715**	**$1,211**

In the first year of the Entegrus / STEI amalgamation, an increase in System Access spending of $1.2M over Plan was experienced.

This increase was largely driven by growth in St. Thomas. Similar to 2016, Entegrus – St. Thomas saw another 6 residential development projects, some of which were the subject of earlier service area amendments. Additionally, Entegrus – Main continued to see residential growth in Mount Brydges with over 4 residential developments, as well as residential growth in Strathroy.

In 2018, Entegrus also saw the start of “Fibre to the Home” projects, primarily within the Chatham community. These projects were driven by multiple fibre companies working independently to aggressively expand their networks and requires Entegrus to perform make-ready work requiring numerous engineering studies and in many cases asset replacements. This work is partially offset by capital contributions. As this work was not previously planned for in Entegrus’ 2016 DSP, a new project referred to above as “Third Party Attachments” has been added to track these investments over the Historic Period and the Forecast Period.

4.4.4.4.2 System Renewal

Table 4-32: 2018 System Renewal Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2018 Plan	2018 Plan	2018 Plan	2018 Actual	Variance
1	Critical Defect Replacements	$400	$0	$400	$168	-$232
2	Emergency Response	$230	$0	$230	$964	$734
3	Metering Renewal	$307	$0	$307	$897	$590
4	Miscellaneous System Renewal	$0	$0	$0	$0	$0
5	Operation Support Capital	$694	$0	$694	$825	$131
6	Pole Replacement	$135	$0	$135	$483	$348
7	Transformer Replacement	$228	$0	$228	$40	-$188
8	Voltage Conversion	$2,160	$1,520	$3,680	$1,141	-$2,539
9	**Subtotal System Renewal**	**$4,154**	**$1,520**	**$5,674**	**$4,518**	**-$1,156**

In 2018, System Renewal investment was $1.2M less than Plan.

This variance primarily relates to the delay of previously planned Voltage Conversion work in order to complete the customer driven work related to System Access. This is offset by additional spending Emergency Response and Metering Renewal.

Entegrus experienced two major storms in 2018, largely impacting the Entegrus – Main service territory. The first store occurred on April 14, 2018, resulting in significant ice accumulation throughout Chatham-Kent and Middlesex counties. This ice storm was declared a Major Event due to the outage impacts Entegrus’ customers saw. The second storm occurred on May 4, 2018, resulting in significant wind speeds throughout most of Chatham-Kent. This storm was not declared a Major Event since a significant portion of Entegrus’ outages were the result of Loss of Supply. Both events drove additional emergency response above the normal planned amount.

Entegrus has also experienced a continued increase in Metering Renewal investments compared to Plan. As discussed previously, Entegrus was one of the first LDCs in Ontario to install smart meters starting in the mid-2000’s. Accordingly, additional investments have continued to be made to reflect the increasing number of failures as smart meters neared end of life. Due to poor communication with some older models, manufacturer support ending on older models, meters with outdated seals and model revisions, management has continued increased the scope of this program to ensure improved communication and reduce downtime.

4.4.4.4.3 System Service

Table 4-33: 2018 System Service Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2018 Plan	2018 Plan	2018 Plan	2018 Actual	Variance
1	Metering Upgrades	$0	$0	$0	$80	$80
2	Miscellaneous System Service	$0	$0	$0	$0	$0
3	System Automation	$400	$0	$400	$306	-$94
4	System Modernization and Planning	$676	$100	$776	$827	$51
5	System Reinforcement	$0	$0	$0	$0	$0
6	**Subtotal System Service**	**$1,076**	**$100**	**$1,176**	**$1,213**	**$37**

Entegrus invested an additional $37k above plan for System Service. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

4.4.4.4.4 General Plant

Table 4-34: 2018 General Plant Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2018 Plan	2018 Plan	2018 Plan	2018 Actual	Variance
1	Building	$120	$5	$125	$525	$400
2	IT Hardware	$91	$60	$151	$565	$414
3	IT Software	$227	$60	$287	$386	$99
4	Miscellaneous General Plant	$20	$20	$40	$117	$77
5	Rolling Stock	$460	$20	$480	$262	-$218
6	Tools	$105	$0	$105	$118	$13
7	**Subtotal General Plant**	**$1,023**	**$165**	**$1,188**	**$1,973**	**$786**

In 2018, Entegrus invested $786k above Plan in terms of General Plant.

As discussed in Section 1.4.6, Entegrus undertook a significant project to update and modernize its Control Room and extend Control Room operations to the recently amalgamated St. Thomas service area. This project primarily accounted for the additional investment in Entegrus' Chatham Building, IT Hardware and IT Software projects. Additionally, Entegrus was required to update servers in the recently amalgamated St. Thomas to support the IT infrastructure of the new organization. This also resulted in an additional investment to IT Hardware.

4.4.4.5 2019 Plan vs. 2019 Actual

4.4.4.5.1 System Access

Table 4-35: 2019 System Access Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2019 Plan	2019 Plan	2019 Plan	2019 Actual	Variance
1	**System Access**					
2	Commercial and Industrial Rebuild	$272	$0	$272	$624	$352
3	Contributed Capital	-$375	-$100	-$475	-$3,357	-$2,882
4	Customer Connections: Commercial & Industrial	$132	$0	$132	$755	$623
5	Customer Connections: Residential & Subdivision	$454	$200	$654	$2,221	$1,567
6	Delta - Wye Service Conversions	$0	$0	$0	$126	$126
7	Engineering Support Capital	$628	$0	$628	$782	$154
8	Miscellaneous System Access	$314	$0	$314	$252	-$62
9	Third Party Attachments	$0	$0	$0	$959	$959
10	**Subtotal System Access**	**$1,425**	**$100**	**$1,525**	**$2,362**	**$837**

In 2019, Entegrus invested $837k above Plan with respect to System Access.

As discussed previously, Entegrus continued to experience residential growth in St. Thomas, Strathroy, Mount Brydges, as well as Chatham. Also, similar to 2018, Entegrus continued to receive requests in Chatham related to fibre installations recorded under Third Party Attachments which drove additional Engineering Support Capital.

This growth drove a significant increase in Contributed Capital in 2019.

4.4.4.5.2 System Renewal

Table 4-36: 2019 System Renewal Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2019 Plan	2019 Plan	2019 Plan	2019 Actual	Variance
1	Critical Defect Replacements	$415	$0	$415	$276	-$139
2	Emergency Response	$230	$0	$230	$497	$267
3	Metering Renewal	$313	$0	$313	$1,087	$774
4	Miscellaneous System Renewal	$0	$0	$0	$7	$7
5	Operation Support Capital	$705	$0	$705	$1,035	$330
6	Pole Replacement	$137	$0	$137	$402	$265
7	Transformer Replacement	$232	$0	$232	$100	-$132
8	Voltage Conversion	$2,100	$1,560	$3,660	$1,189	-$2,471
9	**Subtotal System Renewal**	**$4,131**	**$1,560**	**$5,691**	**$4,592**	**-$1,099**

In 2019, Entegrus invested $1.1M less than Plan in terms of System Renewal.

Consistent with 2018, this was a result of delaying planned Voltage Conversion work in favour of increased customer driven requests in System Access. Also consistent with 2018, this was offset by increased spending in Metering Renewal as management continued to focus on replacing aging smart meter infrastructure. Please refer to Section 4.4.4.2.2 for additional details.

4.4.4.5.3 System Service

Table 4-37: 2019 System Service Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2019 Plan	2019 Plan	2019 Plan	2019 Actual	Variance
1	Metering Upgrades	$0	$0	$0	$123	$123
2	Miscellaneous System Service	$0	$0	$0	$0	$0
3	System Automation	$400	$0	$400	$304	-$96
4	System Modernization and Planning	$683	$100	$783	$796	$13
5	System Reinforcement	$0	$0	$0	$0	$0
6	**Subtotal System Service**	**$1,083**	**$100**	**$1,183**	**$1,223**	**$40**

Entegrus' 2019 System Service was over Plan by $40k. Based on the materiality threshold (see Section 4.4), this amount is deemed immaterial.

4.4.4.5.4 General Plant

Table 4-38: 2019 General Plant Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2019 Plan	2019 Plan	2019 Plan	2019 Actual	Variance
1	Building	$110	$5	$115	$832	$717
2	IT Hardware	$88	$49	$137	$199	$62
3	IT Software	$237	$49	$286	$676	$390
4	Miscellaneous General Plant	$20	$20	$40	$17	-$23
5	Rolling Stock	$475	$0	$475	$560	$85
6	Tools	$106	$0	$106	$100	-$6
7	**Subtotal General Plant**	**$1,036**	**$122**	**$1,158**	**$2,383**	**$1,225**

In 2019, Entegrus invested $1.2M above plan in General Plant. This mostly relates to investments in Building and IT Software.

The additional building investments primarily relates to one significant physical project in Chatham and an accounting adjustment. Entegrus undertook an expansion and restructuring of Chatham's Engineering department to bring the team together in one space, in closer proximity to the Lines department. In 2019, Entegrus was required to record any leases as capital assets per a new IFRS standard that became effective in 2019. Accordingly, the Strathroy building lease was recorded as capital (instead of an expense as it had been previously) to meet this new IFRS standard.

The additional investments in IT Software relates to a significant project to merge the former STEI's CIS system into Entegrus' CIS system. This project is further discussed in Section 3.3.3.

4.4.4.6 2020 Plan vs. 2020 Actual

4.4.4.6.1 System Access

Table 4-39: 2020 System Access Projects ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2020 Plan	2020 Plan	2020 Plan	2020 Actual	Variance
2	Commercial and Industrial Rebuild	$274	$0	$274	$301	$26
3	Contributed Capital	-$375	-$100	-$475	-$2,726	-$2,251
4	Customer Connections: Commercial & Industrial	$133	$0	$133	$788	$654
5	Customer Connections: Residential & Subdivision	$459	$200	$659	$2,915	$2,256
6	Delta - Wye Service Conversions	$0	$0	$0	$33	$33
7	Engineering Support Capital	$637	$0	$637	$1,028	$391
8	Miscellaneous System Access	$317	$0	$317	$415	$98
9	Third Party Attachments	$0	$0	$0	$767	$767
10	**Total System Access**	**$1,446**	**$100**	**$1,546**	**$3,519**	**$1,973**

In 2020, Entegrus invested $1,973k above plan in System Access.

This variance is reflective of the surge in 2020 in already high residential subdivision growth in St. Thomas, as well a Strathroy, Mount Brydges and Chatham. Higher-than-anticipated commercial and industrial growth also coincided with this surge. The significant overall growth occurred despite many developers temporarily putting System Access requests on hold due to the pandemic between March 2020 and June 2020. This is further discussed in Section 1.4.6.

Further, like previous years, Entegrus continued to receive and address significant make-ready requests (third party attachments) related to fibre installations, particularly in Chatham. Due to the volume of these projects, Entegrus incurred higher Engineering Support Capital, as shown above, to facilitate the system design requirements of these projects.

Additionally, due to the COVID-19 pandemic, Entegrus experienced supply chain shortages in 2020 and 2021. These shortages led to longer lead times and price inflation on key inputs. Entegrus worked to mitigate these challenges, however these dynamics factored into the variances above. Please see Section 2.2.2.4 for more details.

The 2020 capital contributions of $2,251k were, accordingly, significantly higher than budget, and partially offset the increase in System Access.

4.4.4.6.2 System Renewal

Table 4-40: 2020 System Renewal ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2020 Plan	2020 Plan	2020 Plan	2020 Actual	Variance
1	Critical Defect Replacements	$395	$0	$395	$243	-$152
2	Emergency Response	$230	$0	$230	$727	$497
3	Metering Renewal	$319	$0	$319	$1,245	$926
4	Miscellaneous System Renewal	$0	$0	$0	$135	$135
5	Operation Support Capital	$716	$0	$716	$897	$182
6	Pole Replacement	$137	$0	$137	$933	$796
7	Transformer Replacement	$232	$0	$232	$147	-$85
8	Voltage Conversion	$1,740	$1,560	$3,300	$1,794	-$1,506
9	**Total System Renewal**	**$3,769**	**$1,560**	**$5,329**	**$6,121**	**$792**

In 2020, Entegrus invested $792k above plan in System Renewal.

As discussed in Section 1.5.1, this increase was driven by remediation work to address portions of the Legacy Entegrus distribution system which had aged and degraded beyond the expectation of the 2016 DSP. This degradation had also been seen through a corresponding deterioration in reliability metrics starting in 2017.

Accordingly, a key focus in early 2020 was pole replacement to remediate the most at-risk poles. This initially involved the replacement of the 28 poles in the southwest region. After the onset of the pandemic, line crews continued to work in the field and were re-organized two-person units (driving in separate vehicles). Significant additional safety precautions were added, including but not limited to: four separate lines encampments (two in the Chatham operations centre, one in the St. Thomas operations centre and one in the Strathroy operations centre), FR masks / face shields, portable wash stations and portable washrooms and additional practices when working with customers and contractors. From March 2020 through June 2020, with many developers temporarily putting System Access requests on hold due to the pandemic and in-person (physical) trades training shut down, the engineering department (working primarily virtually) and lines crews were re-tasked to focus primarily on System Renewal. The two-person line units initially focused on system inspection and remediation of discovered deficiencies. This later progressed to resumption of pole replacement work, involving multiple units co-ordinating together, and finally a full resumption of all construction activities, while maintaining the additional requirements to meet COVID guidelines. Thereafter, in the summer of 2020, System Access requests resumed. For the balance of 2020, crew sizes were expanded to facilitate work on larger capital jobs, with the separate vehicle requirements and the other significant safety precautions remaining in place.

Additionally, due to the COVID-19 pandemic, Entegrus experienced supply chain shortages in 2020 and 2021. These shortages, led to longer lead times and price inflation on key inputs. Entegrus worked to mitigate these challenges, however these dynamic factored into the variances above. Please see Section 2.2.2.4 for more details.

As noted in Section 4.4.5.3.3, Legacy Entegrus was among the earliest utilities to deploy smart meters in the mid-2000's. Management has continued to stage replacement and re-sealing of Entegrus' aged fleet of smart meters and modernize the associated collection and data processing infrastructure. Primarily to offset these additional metering capital expenditures and ensure manpower levels, Entegrus chose to delay certain planned voltage conversion projects. This can be seen by the Voltage Conversion variance in line 8 of the table above.

4.4.4.6.3 System Service

Table 4-41: 2020 System Service ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2020 Plan	2020 Plan	2020 Plan	2020 Actual	Variance
1	Metering Upgrades	$0	$0	$0	$84	$84
2	Miscellaneous System Service	$0	$0	$0	$116	$116
3	System Automation	$425	$0	$425	$517	$92
4	System Modernization and Planning	$716	$100	$816	$1,014	$198
5	System Reinforcement	$0	$0	$0	$0	$0
6	**Total System Service**	**$1,141**	**$100**	**$1,241**	**$1,731**	**$490**

In 2020, Entegrus invested $490k above plan in System Service.

This primarily relates to the Chatham M21 sectionalization project, needed to proactively address what had become, one of the worst performing feeders in the system. This project refurbished and repurposed certain existing under-utilized automated switch gear to provide improved outage performance. This project is discussed in additional depth in Section 2.1.3.1.

4.4.4.6.4 General Plant

Table 4-42: 2020 General Plant ($000's)

Line No.	Projects	Entegrus - Main	Entegrus - St. Thomas	Total Entegrus		
		2020 Plan	2020 Plan	2020 Plan	2020 Actual	Variance
1	Building	$110	$5	$115	$747	$632
2	IT Hardware	$94	$49	$143	$335	$192
3	IT Software	$202	$49	$251	$535	$284
4	Miscellaneous General Plant	$20	$20	$40	$62	$22
5	Rolling Stock	$570	$0	$570	$52	-$518
6	Tools	$110	$0	$110	$74	-$36
7	**Total General Plant**	**$1,106**	**$122**	**$1,228**	**$1,805**	**$577**

In 2020, Entegrus invested $577k above plan in General Plant.

This building investments relate to both business continuity renovations and building improvements to accommodate the consolidation of the Strathroy Customer Service team into St. Thomas (within the existing St. Thomas building footprint) in the summer of 2020. These 2020 investments are described in further detail in Section 3.3.4.

The business continuity renovations were initially unplanned and commenced after the onset of the pandemic. These included the addition of glass barriers and optimization of floor space to create additional physical distancing and partitioning between Customer Service cubicles. Additional investments in IT Hardware and IT Software were also required to facilitate work from home, which commenced for many staff in mid-March 2020. Beyond assisting with employee safety during the ongoing pandemic, these investments will help mitigate seasonal flu risk for employees on a go forward basis, as well as other potential business continuity events that could inhibit physical presence in the building in the future.

The above incremental business continuity investments were offset by a delay in purchasing a double bucket truck, which was originally scheduled for delivery in Q4 of 2020. Due to manufacturing delays, the vehicle was not received until 2021.

4.4.5 Forecast Period Plan

4.4.5.1 Summary

The following table summarizes the planned capital expenditures by investment category over the DSP's Forecast Period.

Table 4-43: Entegrus Capital Expenditures 2021-2025

Line No.	Description	2021	2022	2023	2024	2025
1	System Access	$5,867	$4,308	$6,010	$3,909	$3,926
2	System Renewal	$7,238	$7,669	$7,872	$9,380	$9,395
3	System Service	$1,063	$968	$987	$1,944	$1,519
4	General Plant	$1,974	$2,051	$2,088	$2,121	$2,150
5	**Total Expenditure**	**$16,142**	**$14,996**	**$16,957**	**$17,355**	**$16,991**
6	Capital Contributions	-$3,367	-$2,300	-$2,356	-$2,413	-$2,471
7	**Net Capital Expenditures**	**$12,775**	**$12,696**	**$14,601**	**$14,942**	**$14,520**

As the above table indicates, System Access is a major component of the planned expenditures. This is driven by the previously noted strong Residential customer growth that has occurred in St. Thomas, as well as high growth in in other communities such as Strathroy, Mt. Brydges and Chatham (described in Section 1.4.6). While this strong growth has continued through 2021, it is expected to moderate throughout the remainder of the Forecast Period as discussed in Section 1.4.6. Notably, System Access also includes a 2023 investment for a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas in 2023 as discussed in Section 4.2.1 and Section 4.2.2. As described, Entegrus is investigating other solutions to address this loading capacity issue in St. Thomas, but a decision regarding these alternatives has yet to be made.

As noted throughout this document, Entegrus' 2021-2025 DSP continues to target System Renewal investment to replace deteriorated and technically outdated electrical system assets. The prevalence of such is demonstrated by many key asset categories having significant percentages of assets assessed as "Poor" or "Very Poor" in the ACA (see Attachment C). This dynamic, and the customer reliability implications, are more fully explained in Section 1.5.1.

A significant portion of the 2021-2025 System Renewal forecast targets the continued work to convert the legacy low-voltage feeder infrastructure to a modern, 27.6 kV feeder construction standard Entegrus is implementing across its service territory. The customer engagement process for this DSP resulted in additional conversion investment being planned for 2024/2025 as described in Section 4.1.3.2. Supplementing the targeted area voltage conversion work is the continuation of reactive replacement of other end-of-life overhead and underground infrastructure, as identified by crew inspections and supported through risk-based asset intervention analysis.

System Renewal also includes the commencement of replacing Entegrus' aged fleet of smart meters and the associated collection and data processing infrastructure. Having been among the earlier utilities to deploy smart meters in the mid-2000's, a portion of Entegrus' meters are at or near end of life and will need to be re-sealed or replaced during the Forecast Period. Consistent with the age of the meters themselves, Entegrus' meter data collection and processing infrastructure has now been in service for approximately 15 years and exhibits a number of operating limitations typical for technology assets approaching functional obsolescence. Based on these considerations, discussed in more detail below, Entegrus will also focus Forecast Period expenditures on an overhaul of its Advanced Metering Infrastructure ("AMI") assets.

An important dimension of planned 2021-2025 System Service investments is the planned addition of one new trunk feeder and the associated feeder position at Hydro One's Edgeware transformer station (TS) in St. Thomas. This project responds to the current needs within the system to support resiliency as well as anticipated development activities. This project will enhance Entegrus' overall operational flexibility to respond to major C&I connection requests.

As noted throughout this document, System Service includes automated switching investments in Chatham and St. Thomas planned for 2024/2025 based on customer engagement. See Section 4.1.3.2.

The General Plant portfolio includes normal-course investments in replacement of end-of life fleet units, upkeep of the facilities and lifecycle-based renewal of IT assets. Beyond these cyclical activities, the General Plant portfolio includes the funds for completion of the remaining post-amalgamation integration work (e.g. operating centre consolidation), and IT investments to expand the use of hyperconverged infrastructure, add data storage capacity, and others.

The above summary is described in further detail by asset category and project level detail below.

4.4.5.2 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 Entegrus' assets. Also falling into the scope of System Access work are the investments associated with mandated service obligations, including the AMI infrastructure replacements and enhancements.

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 Entegrus bases its forecasts for connection and service relocation-related parts of the System Access portfolio on its 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, Entegrus has historically re-allocated the necessary funds to System Access by making adjustments to the scope of other planned projects where it has some pacing discretion (typically the System Renewal investments).

Accordingly, a current challenge is that unprecedented growth has occurred simultaneous with the increasing need to address aged and degraded infrastructure. In the design phase of this DSP, it was anticipated that due to the pandemic, System Access would slow and then decline to lower than Historical Period levels in 2022-2025 – which would allow proportionately more resource dedication to System Renewal. This expectation was reinforced when many developers put System Access requests on hold between March 2020 and June 2020 and facilitated a shift in focus to System Renewal work. However, when Ontario pandemic restrictions eased in the summer of 2020, growth surged again, particularly in St. Thomas, Strathroy, Mount Brydges and Chatham. This surge has continued into September 2021. In recognition that moving forward, both System Access and System Renewal need to be addressed and balanced, management updated this DSP filing in September 2021 to adjust 2022-2025 System Access by an aggregate increase of $3M over prior expectations while maintaining System Renewal forecast levels. This coincides with Entegrus increasing its roster and utilization of underground and overhead contractors in the latter part of the Historical Period. At the same time, management has earmarked two investments planned in latter part of the Forecast Period (see Section 4.1.3.2) for timing re-examination in 2024 based on prevailing circumstances at that time, including reliability metrics and the level of capital requirements at that time.

The scope and annual volumes of work associated with mandated service obligations (such as the AMI infrastructure deployments or lifecycle management) are subject to a somewhat greater degree of planning discretion, provided the work in question is consistent with the requirements of relevant regulatory authorities such as Measurement Canada or the Electrical Safety Authority. Overall, however, System Access investments represent the part of Entegrus' capital portfolio where it has the least amount of discretion as to the scope and timing of investments. Table 4-44 provides the breakdown of Entegrus' planned System Access Investments.

Table 4-44: 2021-2025 System Access Expenditure Plan ($'000s)

Line No.	Description	2021	2022	2023	2024	2025
1	Commercial and Industrial Rebuild	$327	$333	$340	$347	$354
2	Contributed Capital	-$3,367	-$2,300	-$2,356	-$2,413	-$2,471
3	Customer Conns: Commercial & Industrial	$106	$108	$110	$112	$114
4	Customer Conns: Residential & Subdivision	$3,753	$2,562	$2,604	$2,191	$2,235
5	Delta - Wye Service Conversions	$253	$100	$80	$60	$0
6	Edgeware Capacity Enhancements	$0	$0	$1,700	$0	$0
7	Engineering Support Capital	$765	$780	$796	$812	$828
8	Miscellaneous System Access	$77	$79	$81	$82	$84
9	Third Party Attachments	$587	$346	$300	$306	$312
10	**Total System Access**	**$2,499**	**$2,008**	**$3,654**	**$1,496**	**$1,455**

4.4.5.2.1 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). As noted earlier in this DSP, Entegrus attempts to avoid connecting new customers to its legacy low-voltage distribution systems. To this end, every connection application with anticipated capacity above 200 kW undergoes review by Entegrus' Planning staff. In cases where doing so is practical, Entegrus attempts to bypass the low-voltage feeders for these types of connections, which occasionally involves larger connection infrastructure costs that Entegrus absorbs. In Entegrus' assessment, doing so constitutes a reasonable economic trade-off given its objectives to eliminate the lower-voltage systems as soon as practicable.

4.4.5.2.2 Customer Connections: Commercial and Industrial

The scope, nature and timing considerations driving these two investment programs are equivalent to the Residential Connection programs. The only notable difference is the customer class involved, and by extension, the magnitude and criticality of requisite investments. Entegrus' C&I customers are major economic pillars of the communities that the Entegrus serves, and as such, accommodating any requests for capacity expansion or other modifications, or preventing any avoidable power outages is a major planning and operational priority.

While Entegrus regularly engages its existing C&I customers to discuss their ongoing and future service needs, forecasting the year-over-year expenditures for this category is a challenging task, given that 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, Entegrus relies on past expenditure trends to establish the annual budgets and five-year outlooks for these two programs. As with their residential program equivalents, these programs are driven by the Customer and Community Focus, Sustainable Growth and Operational Effectiveness Planning Objectives. They are also primarily aligned with the RRF Customer Focus and Operational Effectiveness drivers.

4.4.5.2.3 Customer Connections: Residential & Subdivision

4.4.5.2.3.1 Residential Connections

All work underlying this program is a function of requests from new or existing residential customers to connect, upsize the capacity or modify the configuration of their existing service connections. All customer connection requests undergo evaluation through the connection process described in Entegrus' Conditions of Service. Prior to new connection work proceeding, customers must accept the terms of the Offers to Connect that outline the scope of work and cost responsibility (if any) on the part of the customer.

In many cases, a new connection may involve as little effort as the installation of a new revenue meter. More advanced 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, Entegrus 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, Entegrus discusses them with requesting customers and alerts them of any technical considerations or scope implications inherent in the available alternatives. Entegrus retains the final say as to the ultimate technical configuration of the new or modified facilities. Given their customer-driven nature and execution via a standardized process, the Residential New Construction and Rebuild programs correspond to Entegrus' Customer and Community Focus, Sustainable Growth and Operational Effectiveness Planning Objectives. As such, they are also primarily aligned with the RRF Customer Focus and Operational Effectiveness drivers.

4.4.5.2.3.2 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.

On average, Entegrus connects five new developments each year. Prior to commencing any connection work, Entegrus prepares an Offer to Connect ("OTC") 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 Entegrus and those eligible for construction by third parties should the developer elect such an option.

Entegrus 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. Entegrus 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 Entegrus is obligated to interconnect 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. The program supports the Sustainable Growth, Customer and Community Focus and Operational Efficiency objectives, and is consistent with the RRF Customer Focus and Operational Effectiveness outcomes.

4.4.5.2.4 Delta-Wye Service Conversions

This program responds to the direction from the Electrical Safety Authority to the industry to modify the existing Delta Wye transformer connection configurations. Being an outcome of a specific requirement from a regulator, the program is non-discretionary in nature and timing and is to occur within the next two years. It corresponds to the Public Safety planning objective and Customer Focus RRF outcome.

4.4.5.2.5 Capacity Enhancements

This program targets the construction of a new supply feeder and the associated breakers, switches, bus work and protection scheme modifications at Hydro One’s Edgeware transmission stations (TS) where the feeders would originate. As discussed above, Entegrus has also, in multiple instances, explored the need for a similar breaker and feeder addition project at Chatham’s Kent TS. While the following passages discuss the analysis underlying the potential Kent TS breaker expansion as well, this project is not currently included into the DSP. Should the need and feasibility be confirmed, Entegrus anticipates that the bulk of the project’s capital cost would be provided by the benefitting customer.

The following passages describe the results of planning capacity and contingency studies that Entegrus conducted to explore the anticipated system needs based on the latest available connection queue information and a range of scenarios reflecting realistic system operation circumstances. A key input into these technical studies is a bottom-up feeder by feeder load forecast that incorporated all known upcoming customer connections (approximately 980 new customers across 20 planned developments in the two communities), adding a modest 1% baseline organic growth assumption. The load forecast estimated the load on each feeder for each hour over the 2021-2025 timeframe, using separate load profiles reflective of the past actual loading patters in each community. The table below provides the results of the peak load forecast underlying the planning studies.

Table 4-45: Chatham and St. Thomas System Peak Forecasts (MVA)

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chatham	94.4	101.8	94.2	97.6	98.5	100.3	102.4	103.2	104.4
St. Thomas	49.1	54.6	61.3	57.8	59.1	63.0	63.6	64.2	64.8

Using the load forecast data inputs, Entegrus calculated available capacity under three system conditions: Normal State (N-0), Loss of 1 Feeder (N-1), and Loss of 2 Feeders (N-2). In each scenario, results considered capacity under two capacity thresholds;

- *Planning Limit* – a high-level threshold, within which additional load connections can proceed without more detailed analysis (set at 65% of equipment ratings for Chatham and at 50% for St. Thomas given a lower number of feeders in the latter).

- *Emergency Limit* – a threshold equal to 100% of equipment ratings in both cities, for operation under N-1 and N-2 scenarios. While a 100% threshold is acceptable for occasional operation, prolonged periods result in premature asset deterioration and lower operating flexibility.

The table below captures the feeder loading limits for both communities studied.

Table 4-46: Feeder Loading Limits Study Assumptions

Description	N-0 (Planning Limit)	N-1	N-2
Chatham	390 A / 18.7 MVA	600 A / 28.8 MVA	600 A / 28.8 MVA
St. Thomas	300 A / 14.4 MVA	600 A / 28.8 MVA	600 A / 28.8 MVA

As it evaluated the scenarios, Entegrus calculated two metrics: Peak Remaining Capacity (maximum aggregate load that could be added to the system without exceeding applicable rating limitations), and Peak Unserved Load (load that could not be served due to equipment rating limitations). Importantly, a system experiencing a contingency can simultaneously have remaining peak capacity *and* unserved load, as switching and tie limitations, geographical load distribution and large point loads that cannot be split across multiple backup feeders.

St. Thomas: Operating Margin for Load Restoration

The need for the new St. Thomas feeder and breaker position is driven by operational flexibility considerations under contingency events. With a new residential subdivision in the development plans, coupled with modest (1%) organic load growth assumptions across the city, both the Planning and Contingency Capacity limits are violated by the end of the study period as shown in the tables below without an addition of a new breaker / feeder combination.

Table 4-47: St. Thomas Remaining Planning Capacity - 2025

Description	0 New Breakers		1 New Breaker	
	Remaining Capacity (MVA)	Load Above Planning Limit (MVA)	Remaining Capacity (MVA)	Load Above Planning Limit (MVA)
Normal State	-	7.2	7.2	-

Table 4-48: St. Thomas Remaining Contingency Capacity - 2025

Description	0 New Breakers		1 New Breaker	
	Remaining Capacity (MVA)	Unserved Load (MVA)	Remaining Capacity (MVA)	Unserved Load (MVA)
1 Feeder Loss (N-1)	20.3	1.2	50.4	-
2 Feeder Loss (N-2)	-	12.3	20.4	1.2

The results of the Time-Based Contingency Analysis, where forecasted load for each hour of the year was evaluated for feasibility of restoration under contingency scenarios, also reveals the need for an additional breaker / feeder from Edgeware (or an alternative solution) to ensure that load can be restored under N-2 conditions. The heat maps shown in the Figures below showcase the positive impact the addition of a new (fourth) breaker position and feeder would have on Entegrus' power restoration abilities in St. Thomas under an N-2 contingency scenario.

Figure 4-6: Time-Based Continency Analysis: 0 New Breakers, N-2

	2025																							
Month/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	97%	61%	74%	94%	97%	100%	100%
2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	97%	87%	87%	83%	83%	77%	63%	53%	53%	60%	67%	77%	97%	100%
7	100%	100%	100%	100%	100%	100%	100%	100%	100%	94%	74%	42%	13%	3%	3%	0%	0%	0%	0%	3%	3%	6%	48%	94%
8	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	90%	58%	45%	32%	26%	23%	16%	13%	16%	19%	19%	29%	84%	100%
9	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	93%	80%	77%	73%	63%	43%	40%	47%	57%	63%	90%	100%	100%
10	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
11	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
12	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	61%	84%	90%	100%	100%	100%

Figure 4-7: Time-Based Contingency Analysis: 1 New Breaker, N-2

Month/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
2	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	93%	93%	87%	93%	97%	97%	100%	100%	100%
7	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	97%	97%	94%	84%	77%	68%	52%	52%	52%	68%	84%	94%	100%	100%
8	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	97%	90%	87%	87%	87%	97%	100%	100%	100%	100%
9	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
10	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
11	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
12	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%

Based on the above analysis, Entegrus has worked with Hydro One to complete a Customer Impact Assessment (CIA) for the modifications required at Edgeware TS, which determined that the project would have no adverse impact on the station's existing load-serving capacity or other dimensions.

The cost of the Edgeware TS modifications is included in the 2023 capital budget and is further explained below in Section 4.4.1.1.

Chatham: Connection Capacity Increase (Not Currently included in the DSP)

The potential need for a new Kent TS feeder and breaker position construction in Chatham is driven by the developments associated with anticipated load growth, namely:

- Applications by large customers in 2019 and 2020 that would have individually resulted in incremental connection capacity of up to 23 MW by 2023 (these applications were both subsequently cancelled) for non-utility reasons;

- Ongoing re-zoning in the Chatham's northern part, which is expected to drive demands for additional commercial and industrial activity in the area;

- The increasing frequency with which Entegrus is contacted by commercial greenhouse operators from the nearby Leamington area to explore opportunities for future facilities.

As stated above, Entegrus is not currently planning to proceed with this project until the need is confirmed by the benefitting customer meeting the requisite connection milestones.

In terms of the potential 23 MW load scenario described above, given the size of the load, the technical study suggested that the new feeder should be constructed to a higher rating than the current standard of 600 A. Given that connection capacity shortages are once again emerging in the nearby Leamington area (a major local centre for greenhouse vegetable cultivation), Entegrus expects to receive more interest for similar facilities in the coming years beyond the current customer.

Table 4-49: Chatham Remaining Planning Capacity - 2025

Description	0 New Breakers		1 New Breaker		2 New Breakers	
	Remaining Capacity (MVA)	Load Above Planning Limit (MVA)	Remaining Capacity (MVA)	Load Above Planning Limit (MVA)	Remaining Capacity (MVA)	Load Above Planning Limit (MVA)
Normal State	26.6	-	45.3	-	64.1	-

As the Table above indicates, the planning capacity in Chatham would not be violated under the normal planning capacity conditions. However, this is not the case under the contingency capacity scenarios captured in the Table below.

Table 4-50: Chatham Remaining Contingency Capacity - 2025

Description	0 New Breakers		1 New Breaker		2 New Breakers	
	Remaining Capacity (MVA)	Unserved Load (MVA)	Remaining Capacity (MVA)	Load Above Planning Limit (MVA)	Remaining Capacity (MVA)	Load Above Planning Limit (MVA)
1 Feeder Loss (N-1)	67.8	11.8	97.2	1.0	126.0	-
2 Feeder Loss (N-2)	34.1	15.0	63.3	5.7	74.6	5.7

As the above table indicates, despite significant remaining emergency capacity in the system, there would be unserved load during either an N-1 or an N-2 contingency event. Adding an extra breaker reduces the amount of unserved load materially, however not completely so. Accordingly, Entegrus tested another scenario where two new breaker positions were added at Kent TS. This analysis revealed that some load would still remain unserved under an N-2 contingency scenario due to system configuration limitations in the city's northern part. Moreover, the benefits of incremental outage mitigation potential of the second breaker would largely accrue to a single large customer (the new greenhouse facility). Accordingly, Entegrus rejected the two new breakers option as being beneficial to the system as a whole and eliminated it from further analysis at this time. Entegrus will investigate feeder reconfiguration options to improve load restoration flexibility in the northern part of Chatham in the coming years.

The results of Time-Based Contingency Analysis under the N-2 conditions for Chatham similarly showcase an impact that a new breaker / feeder position would make to the area load restoration capabilities in the event of a double contingency, as showcased in in the figures below.

Entegrus has also completed the Time-Based Contingency Analysis for scenarios where the new large greenhouse load does not materialize at all, or only the first phase is materialized. While under these scenarios the overall system peak load does not change, however system restoration benefits under an N-2 contingency scenario exist under both scenarios regarding the new greenhouse load.

Entegrus has completed a Connection Impact Assessment with Hydro One for the Chatham (Kent TS) breaker and feeder expansion project. No barriers to the project were uncovered in the study.

Had the customer connection requirement materialized, the default alternatives to a load-serving connection and operational capacity expansion project would have been the deferral of investments until a later date when the connection of new load was imminent, or a reduction of the total capacity needs by way of accommodating some or all of the anticipated load growth through non-wires alternatives (e.g. Demand Response, Conservation, etc.). Given the type of load that Entegrus anticipated emerging, the capacity available on the existing system, and the technical planning considerations discussed above, Entegrus determined that these options would not have been feasible.

The investments comprising this program align with Entegrus' Sustainable Growth, Customer and Community Focus and Cost Effectiveness Planning Objectives. They are also aligned with the OEB's Customer Focus and operational Effectiveness Outcomes.

4.4.5.2.6 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 planned capital projects. Over the Historical Period Entegrus has increased the staffing complement of its distribution system engineers and technologists, following a significant reduction as a result of multiple retirements in a short span of time. Engineering personnel are well-versed in modern power system management, including the fundamentals of advanced engineering and design software packages (e.g. GIS, CAD, OMS), and an understanding of asset management as a formal discipline and a practical way of structuring Entegrus decision-making. Entegrus also ensures that its engineering and design personnel dedicate a portion of their time to activities in the field to develop a practical outlook on the implications of their decision-making.

Aside from transforming higher-level planning estimates into specific design drawing and construction materials work orders, Entegrus' engineering and design professionals are directly involved in maintaining compliance with all relevant operational, public safety and customer service standards that Entegrus 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. Entegrus strives to increase the overall throughput efficiency of its engineering and design work my progressively expanding its use of software solutions to manage the manual labour costs. While outsourcing to a third-party contractor represents a potential alternative of accomplishing the requisite activities, this approach is generally inconsistent with Entegrus' vision of building a strong core of internal specialists intimately familiar with the local system characteristics and capable of performing a wide range of analytical tasks. There are instances, however, where certain tasks are outsourced to third parties to manage customer-driven peak periods in workload. This program is driven by Entegrus Safety, Operational Excellence and Cost Effectiveness Planning Objectives. It also corresponds to the RRF Operational Effectiveness Outcome.

4.4.5.2.7 Miscellaneous System Access

Account Cancellation

This program captures the costs of accommodating customer move-outs from their premises and the associated cancellation of accounts. The work associated with this program typically involves physical disconnection at the meter base and the removal of the meter. Other modifications may be necessary depending on the condition of a customer site, planned future use of the associated facilities, etc. The expenditures are a function of the requirements under Entegrus' Distribution License, and as such are non-discretionary.

Capital Expansion Requests

This program captures the costs of accommodating requests from third parties to relocate Entegrus' 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, Entegrus 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, Entegrus 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 Entegrus 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, Entegrus 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 Entegrus' 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, Entegrus reallocates the funds from other types of System Access projects, or else proactive System Renewal expenditure budgets. Operational Efficiency and Customer Focus are the key RRF outcomes underlying this program spending. However, in accommodating the community improvement or infrastructure enhancement projects, the Capital Expansion Request work enables broader economic benefits for the communities served by Entegrus and southwestern Ontario more generally.

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 Entegrus' distribution system and/or making modifications to the existing connection infrastructure. While Entegrus 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. The expenditures comprising this work are associated with the Public Policy Responsiveness RRF driver and Operational Efficiency planning objective.

4.4.5.2.8 Third Party Attachments

This program performed by Entegrus' Engineering divisions covers the cost of work associated with design, testing installation and upkeep of various devices to Entegrus' 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. Entegrus 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 Entegrus is required to complete such work through the conditions of its License. Importantly, a key Asset Management benefit associated with this work stems from the fact that while on-site at these poles, Entegrus takes the opportunity to perform drill testing prior to attachment being installed. Accordingly, it is progressively increasing the amount of pole testing results in an economic manner.

4.4.5.3 System Renewal

The scope and nature of System Renewal work that Entegrus intends to undertake over the Forecast Period represents an increase over the Historical Period, for the reasons described in Section 1.5.1. In identifying the specific candidate locations for planned projects and forecasting the volumes of reactive replacements across specific asset classes, Entegrus relied on the risk-based intervention planning methodology and tools discussed in detail in Sections 3.1.2 and 3.3. The Table below showcases the planned expenditures for this category.

Table 4-51: 2021-2025 System Renewal Expenditure Plan ($'000s)

Line No.	Description	2021	2022	2023	2024	2025
1	Critical Defect Replacements	$322	$375	$383	$391	$378
2	Emergency Response	$457	$466	$475	$485	$494
3	Metering Renewal	$1,394	$1,556	$1,587	$1,619	$1,632
4	Miscellaneous System Renewal	$146	$149	$152	$155	$158
5	Operations Support Capital	$776	$791	$807	$823	$840
6	Pole Replacement	$506	$586	$597	$609	$622
7	Transformer Replacement	$436	$445	$428	$436	$445
8	Voltage Conversion	$3,201	$3,301	$3,443	$4,862	$4,827
9	**Total System Renewal**	**$7,238**	**$7,669**	**$7,872**	**$9,380**	**$9,395**

The increase in 2024 and 2025 forecast System Renewal investment was driven by additional voltage conversion based on findings from the customer engagement process, as more fully described in Section 4.1.3.2.

Entegrus primarily relies on its in-house line crews to perform System Renewal work. However, contract labour is occasionally required to perform specific tasks requiring equipment and skillsets that is not economical for Entegrus to do internally, such as directional drilling or concrete pouring work to facilitate the underground cable renewal. Contract labour is also used to help meet customer-demand driven peaks in workload. Given the size of Entegrus' service territory, driving time is a major consideration in the projects' OM&A and capital construction costs, as well as the outage response times where crew visits are required.

To manage the impact of distance on its operations, Entegrus typically allocates its service territory between Northeastern and Southwestern construction and outage response zones, served by the St. Thomas/Strathroy operating centres, and the Chatham operating centre, respectively. Table 4-52 lists the communities served by each operating centre as of September 2021. The balancing of community operating assignments will be periodically revisited over the Forecast Period.

Table 4-52: Entegrus Communities by Operating Centre as of September 2021

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	✓	

A key aspect of planning the proactive System Renewal work thus involves balancing the availability of construction resources per zone with the areas characterized by the highest system risk inherent in the condition of its asset base, or other risks such known safety issues. In some cases, the scope and location of a given planned project may also be influenced by the location of work in the previous years, such as the voltage conversion work targeting the eventual decommissioning of a specific step-down transformer station. Other considerations identifying specific locations of System Renewal activities involve past reliability performance, work orders from crews conducting line patrols, and/or requests from specific customers or communities identified during customer engagement work.

It is important to note that given the comparatively higher discretion that Entegrus has over the scope and timing of most System Renewal investments, this investment category has historically represented an “overflow” reserve for instances where the forecasted budgets for other programs (most notably System Access) prove insufficient to complete the requisite work volumes. The 2021-2025 capital plan dedicates incremental resources to System Renewal.

As discussed throughout this DSP, Entegrus has taken significant steps to enhance its evidence-based Asset Management work, with the System Renewal portfolio being the primary area benefitting from this work. Given recent reliability trends, Entegrus’ work program attempts to prioritize the investments with the highest potential to eliminate or reduce outage occurrence associated with defective equipment, while making its overhead system more resilient to severe weather events. As it proceeds with implementing its planned 2021-2025 work program, Entegrus will continue refining its approaches to risk-based long-term intervention planning and project-specific prioritization. Moreover, and as discussed in Section 2.1.6.6, Entegrus’ planners expect to progressively enhance the accuracy of their planning- and design-level estimates by undertaking more in-depth review between the forecasted and actual project costs.

4.4.5.3.1 Transformer Replacement and Pole Replacement

These programs capture the costs of replacement of the major components of Entegrus' 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. Entegrus plans to replace an average of 390 poles and 75 transformers per year over the 2021-2025 period. 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 that replaces groups of assets proactively, this part of Entegrus' investment portfolio is dedicated to reactive investments – scheduled in response to work orders from field inspections and/or conducted in response to outage events where equipment cannot be repaired. While the numbers of wood poles and transformers replaced through this program may vary from year to year, in the case of LIS switches, Entegrus attempts to replace an average of 2 units per year, given their long lead time. However, the specific locations may be determined in-year based on the results of inspections or actual experience of operating the switches.

This program's expenditures also include the decommissioning of many of the remaining 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.

As discussed elsewhere in this DSP, Entegrus is currently conducting a smaller-scale pilot project where a randomly selected sample of wood poles from multiple locations and age cohorts undergo drilling each year, to use the results to make broader inferences about the population's health with the help of data science tools. Entegrus' current experimental approach involves prediction of the poles' internal condition using the K-Nearest Neighbours machine learning algorithm ("KNN"), which predicts the poles' internal condition based on their age and geographical location relative to the tested poles. While the results of this experimental analysis do not yet influence the formal calculation of ACA results, they help Entegrus obtain incremental directional insights about the state of their wood poles (and their propensity to fail in service) at a minimal incremental cost. Entegrus will continue refining its predictive approaches over the Forecast Period with the aim of incorporating their insights into the formal ACA assessments in the future.

Although some of the assets replaced through this program are replaced before they actually fail to perform their core function in the service, the program is nevertheless consistent with a Run to Fail AM strategy, as the assets must be identified as having reached the end of life by inspection patrols – meaning they are exhibiting imminent signs of failure. This is distinct from a Proactive / Predictive replacement approach, where deteriorating equipment may be replaced before any signs of imminent failure are visited, based on the results of risk-based analysis. While Entegrus' preference would be to avoid any in-service failures that result in outages, such a scenario is impractical in lieu of its financial and resourcing restrictions. Instead, between the proactive replacement approach associated with the Voltage Conversion Program and the reactive replacement approach underlying this program, Entegrus attempts to strike an optimal balance in terms of overhead asset lifecycle management strategy.

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. The Overhead System Renewal program corresponds to Entegrus' Safety, Sustainable Growth, Customer and Community Focus and Cost Effectiveness Planning Objectives, and Customer Focus and Operational Effectiveness RRF outcomes.

4.4.5.3.2 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 Entegrus' Asset Management 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 Entegrus 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. This program is driven by Entegrus' Safety, Operational Excellence and Cost Effectiveness Planning Objectives. It also corresponds to the RRF Operational Effectiveness Outcome.

4.4.5.3.3 Metering Renewal

4.4.5.3.3.1 AMI Infrastructure Renewal

Over the 2021-2025 Forecast Period approximately 50% of Entegrus' fleet of smart meters will reach the end of their first re-seal period as specified by Measurement Canada. As described in Section 2.1.3.3, 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 (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 the mid-2000's, when, after a successful pilot project, smart meter deployment commenced within Entegrus' 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 Entegrus, 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.

Another risk with continued operation of early AMI infrastructure stems from its potential vulnerability to cybersecurity risk. As the overall volume of operating data and complexity of industry IT systems continue to increase, the impact of a potential cybersecurity breach is magnified.

The status quo of Entegrus' 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. Operation of two smart-metering systems drives complexity in integration with other key business systems, as well as requiring duplication in inventory, and training. Procurement work underlying the planned upgrades involves anticipated harmonization to one smart-metering system.

The key Entegrus Planning Objective coinciding with this investment segment is Operational Efficiency, given the capability enhancements inherent in the newer technology, and the potential for locational work execution synergies when replacing meters and the associated infrastructure concurrently (as Entegrus expects to do). Operational Effectiveness and Public Policy Responsiveness are the RRF Outcomes associated with this segment. This is because the investments seek to ensure that Entegrus' AMI infrastructure is based on modern and efficient technology with a minimal physical and financial footprint, lower support requirements, and is better equipped to mitigate cybersecurity and data integrity risks.

Entegrus 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 a future year. However, Entegrus deems this alternative to be suboptimal given the uncertainty as to its vendor's continued support of the Canadian market, 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 as to technology providers, communication mediums and specific solutions that Entegrus expects to evaluate in detail in the early phases of this project. Entegrus expects to pace the specific timing and sequencing of these investments over the Forecast Period in accordance with the volumes of other types of System Access work, over which it has substantially less discretion.

4.4.5.3.3.2 Meter Re-Sealing

This segment captures the costs of a compliance activity 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, should Entegrus elect to keep the meters in operation past the expiration of its original seal. It is Entegrus' 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 by an additional five years. Given that re-sealing is a regulatory requirement, there are no feasible alternatives to it aside from replacing the meters after the end of their original seal's expiration. Entegrus believes that re-sealing of 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 2.1.3.3, the paced smart meter re-seal and replacement process may require second re-sealings of some units. Given its compliance-driven nature, this investment segment is most closely aligned with the Public Policy Responsiveness RRF Outcome. Within the Entegrus' own planning objectives, Meter Re-Sealing corresponds to the Operational Efficiency objective.

4.4.5.3.3.3 Retail Meter Replacement

This segment captures the expenditures related to replacement of smart meters that fail or sustain irreparable damage in service, are found to be faulty through Entegrus' 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 a function of 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 increasingly probability of in-service failures will require close monitoring, due to the already 15-year-old design and functionalities of some meter units. Given the nature of its underlying activities, this expenditure segment aligns most closely with the Operational Efficiency Planning Objective and the Public Policy Responsiveness RRF Outcome.

4.4.5.3.4 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 Entegrus to forecast the approximate expected volumes of reactive failures in a given 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 Entegrus 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 / predictive asset replacement, Entegrus planners believe that a certain level of reactive equipment failure restoration expenditures constitutes a balanced asset management outcome, as failure signifies that Entegrus 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, Entegrus is a party to several Mutual Aid agreements discussed in Section 2.2.2.4, which enable it to request assistance from Canadian and U.S. utilities as required. This program is driven by Entegrus' Safety and Customer and Community Focus Planning Objectives and corresponds to the RRF Customer Focus and Operational Effectiveness outcome.

4.4.5.3.5 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 our 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.

4.4.5.3.6 Voltage Conversion

Voltage Conversion program is the most significant of Entegrus' proactive System Renewal undertakings that is consistent with the Historical Period. The scope of work associated with this program involves replacement of aged and deteriorated overhead and underground line assets operating at lower voltages (2-, 4-, or 8- kV) with new assets built to a modern 27.6 kV standard. These low-voltage feeders account for a relatively significant contribution to the annual service interruptions caused by Defective Equipment. Moreover, the legacy low-voltage feeders and the step-down distribution substations that supply them are associated with much higher technical losses than higher-voltage equipment built to modern standards. As such, aside from improving reliability, voltage conversion work improves the efficiency of Entegrus' overall system and has a positive impact on customer bills over the longer term.

While low-voltage assets presently exist in almost every community, Entegrus is required to pace and prioritize the specific replacement candidates given the constraints imposed by annual funding allocations and regional labour resources availability. To prioritize among specific projects, Entegrus relies on the Risk-Based approach described in Section 3.3, supplemented by the analysis of local system reliability and other analytical tools and processes comprising its Asset Management process discussed in Section 3.1. Overall, the majority of assets comprising Entegrus' low-voltage feeders are currently in a Fair or Poor condition. The use of AM analytical processes enables Entegrus to identify the geographical and electrical areas with the highest asset risk, as represented by the probability of asset failures and impact of failures on Entegrus' own costs and those incurred by the affected customers.

While individual assets within the scope of each conversion project may be in better condition than the adjacent assets they are being replaced alongside of, the high fixed costs of projects occurring in a given area at times warrant replacement of newer assets to capitalize on locational synergies and advance the overall voltage conversion progress. Importantly, aside from the economics of low-voltage feeder hardware replacement, the conversion projects' pace and timing is driven by the need to decommission aging substations that supply these feeders – before the substation equipment itself requires replacement. As such, aside from its own inherent failure risk mitigation and loss reduction benefits, every low-voltage conversion segment mitigates the financial risk of incurring major substation renewal capital investments.

Given expected timeline to finish conversion, Entegrus 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 defer major station replacement costs while maintaining resiliency and reliability within the system until conversion can occur.

In conducting the voltage conversion work, Entegrus 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, Entegrus always places the new cable segments into rubberized or concrete ducts, to extend the equipment's service lives and simplify future reactive efforts. Aside from adding resilience, reducing losses and mitigating failure risk, voltage conversion creates additional feeder capacity on Entegrus' 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 electric vehicle 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 eventual decommissioning of all the step-down substations, and the resulting foregone capital replacement expenditures and ongoing OM&A cost savings.

As noted above, low-voltage infrastructure entails both underground and overhead line segments in different parts of Entegrus' service territory. Since the commencement of the Voltage Conversion program, Entegrus focussed primarily on the overhead conversion work, given the more immediate impact on reliability through enhanced weather resilience and lower unit costs. As Entegrus approaches completion of the overhead segment conversion in the coming years, it will be required to increase the share of the underground work. At this juncture, Entegrus expects to continue converting the low-voltage feeders on a like-for-like basis in terms of the type of infrastructure (i.e. overhead for overhead, underground for underground).

As with most aging and deteriorated plant that nevertheless remains in service, the primary alternative to asset replacement is the deferral of work – through either postponement of any intervention activities or a completion of refurbishment activities to extend the equipment's lifecycle. Entegrus has determined that deferral is not an economic alternative for this program in 2021-2025, as the intervention expenditures for the conversion investments planned over the 2021-2025 timeframe are lower than the risk costs of leaving the plant for reactive renewal. Moreover, deferral of the conversion work is also suboptimal given Entegrus' objectives of decommissioning all of 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. Further, it was determined in customer engagement for this DSP that customers supported accelerated conversion investment beyond the initial base plan, which led to management updating its plans to conduct additional conversion work in 2021-2025. These plans are further detailed in Table 4-7, Table 4-8 and Section 4.1.3.2.

Asset refurbishment is not a viable option for this program, as limited options are available with respect to the overhead assets, while a general program underground cable injection is largely impractical given the configuration of the majority of Entegrus' underground cable assets that would require coordination of multiple lengthy outages. Even if practical options were available, refurbishment would prevent Entegrus from realizing further savings from line loss reduction, prevent connection capacity expansion, and potentially conflict with its objectives of retiring the substation assets as soon as practicable.

While like-for-like replacement at the same voltage would constitute a less expensive option than conversion work, proceeding with this option would prevent Entegrus from its objectives of decommissioning all of its substation assets, and would limit the extent to of loss reduction. Moreover, the 27.6 kV design is Entegrus' new internal standard, the proliferation of which will enable Entegrus to gradually reduce its inventory costs through standardization of its equipment. While Entegrus reactively replaces individual failing components of low-voltage feeders should these occur before the scheduled area conversion work, reactive replacement is not a viable log-term strategy as it prevents Entegrus 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 the grid modernization objectives of preparing the grid for future penetration levels of electric vehicles, distributed energy sources and self-healing grid configurations.

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. Entegrus 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 material O&M savings, as Entegrus 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 2021-2025 timeframe, Entegrus anticipates that any reductions in Reactive Maintenance spend due will be fully offset by the Risk-Based Maintenance spend associated with patrol-defined rectification of one-off deficiencies.

The program corresponds to Entegrus' Safety, Sustainable Growth, Customer and community Focus, and Operational Excellence Planning Objectives. Operational Efficiency is the primary RRF outcome driving the program expenditures.

4.4.5.4 System Service

Entegrus' portfolio of System Service investments captures the planned activities to reinforce, expand and otherwise modify Entegrus' distribution system. The need for System Service investments typically arises when Entegrus 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. Table 4-53 showcases Entegrus' planned System Service program expenditures over the Forecast Period.

Table 4-53: 2021-2025 System Service Expenditure Plan ($'000s)

Line No.	Description	2021	2022	2023	2024	2025
1	Metering Upgrades	$65	$66	$68	$69	$70
2	Miscellaneous System Service	$102	$94	$96	$98	$100
3	System Automation	$110	$142	$145	$1,085	$643
4	System Modernization and Planning	$436	$537	$548	$559	$570
5	System Reinforcement	$350	$128	$131	$133	$136
6	**Total System Service**	**$1,063**	**$968**	**$987**	**$1,944**	**$1,519**

When planning for System Service investments, Entegrus relies on the insights generated through the analytical activities completed as a part of its Asset Management process, as well as the results of its collaboration with entities during the Regional Planning work. The core inputs to system planning work are Entegrus' 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 Entegrus' occasional 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.

4.4.5.4.1 Metering Upgrades

This program is a subset of the broader metering portfolio discussed in more detail in Section 4.4.5.3.3 related to the lifecycle management of the wholesale revenues meters owned by Entegru.

Entegrus plans to replace or reseal, as permissible, approximately 37 wholesale meters per year over the 2021-2025 Forecast Period. As with residential metering, wholesale meter replacement timing is a function of Measurement Canada requirements and/or any damage or accuracy issues identified in the course of the meters' operation. There are no viable alternatives to the replacement of wholesale meters. As with other metering assets, this investment portfolio aligns with Entegrus' Operational Efficiency Planning Objective and the Public Policy Responsiveness RRF Outcome.

4.4.5.4.2 System Modernization and Planning

This program captures the cost of planned enhancements to Entegrus' 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 Entegrus' 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 duration – an important benefit considering the span of Entegrus' service territory and the resulting outage response logistics.

Over the 2021-2025 Forecast Period, Entegrus expects to deploy 5 new smart switch schemes in its service territory. Entegrus 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. Entegrus estimates that its existing automation schemes deployed in communities of Wallaceburg, Tilbury, Blenheim and Ridgetown have resulted in a combined 18,000 of avoided Customer Hours of Interruption (CHI) between 2017 and 2020. 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.

4.4.5.4.3 System Automation

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, Entegrus believes that the differences between the two types of investments differ too substantially to be readily comparable.

Instead, Entegrus views the automation investments as outage impact mitigation measures that help compensate for the travel distances inherent to its distribution system's geography, compounded by age and condition of the asset base. As such, Entegrus sees automation as a useful complement (rather than substitute) to replacement work, since the comparatively low investments in automation (which reduces some aspects of outages) help pace the renewal work (that enhanced the reliability performance more holistically and carries other benefits that automation does not have).

Distribution automation is also an investment that directly responds to customer preferences. For instance, the automation scheme deployed in Wallaceburg discussed above, was a direct result of consultation with the community's leadership, who conveyed to Entegrus a clear expectation of near-term reliability improvements for the municipality. As discussed in Section 2.3.3.1.2, reliability continues to be an area of concern for Entegrus customers. Having established the value add of this technology over the Historical Period, Entegrus plans to continue deploying it in places where its capabilities can be expected to be impactful. The customer engagement process for this DSP identified customer preference for deployment of additional automated switches in Chatham and St. Thomas to create a dynamic distribution system, as more fully described in Section 4.1.3.2.

Entegrus' internal crews 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 Entegrus 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.

System Automation investments correspond to Entegrus' Customer and Community Focus and Cost Effectiveness Planning Objectives. They are also aligned with the OEB's Customer Focus and Operational Effectiveness Outcomes.

4.4.5.4.4 Miscellaneous System Service

Substation Capital

As discussed in the context of Voltage Conversion programs, a key planning objective for Entegrus 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 for the remainder of their respective lifecycles. These investments are not expected to reach the materiality threshold in any of the Forecast Period years.

4.4.5.5 General Plant

Though General Plant investments target non-system assets, they are critical in supporting Entegrus' 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. Sections 3.3.3 through 3.3.5 discuss the General Plant asset management strategies underlying the planned expenditures showcased in Table 4-54.

Table 4-54: 2021-2025 General Plant Expenditure Plan ($'000s)

Line No.	Description	2021	2022	2023	2024	2025
1	Building	$176	$199	$203	$207	$211
2	IT Hardware	$160	$235	$240	$235	$255
3	IT Software	$320	$315	$320	$325	$310
4	Miscellaneous General Plant	$305	$247	$200	$207	$205
5	Rolling Stock	$805	$841	$908	$925	$943
6	Tools	$209	$213	$217	$222	$226
7	**Total General Plant**	**$1,974**	**$2,051**	**$2,088**	**$2,121**	**$2,150**

All General Plant investments correspond to Entegrus' Operational Efficiency and Employee Safety Planning Objectives and primarily align with the RRF Operational Effectiveness Outcome.

4.4.5.5.1 Tools

This program captures cyclical purchases of various tools and implements used by Entegrus' crews in the course of 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, Entegrus 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 in light of 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.

4.4.5.5.2 Building

This investment program captures the costs of upkeep and enhancements to Entegrus' Operating Centres. Key activities planned for the 2021-2025 timeframe include the St. Thomas building improvements to accommodate the consolidation with the former Strathroy operating centre, and HVAC improvements to the Chatham facility deferred from the Historical Period, and roof upgrades in Chatham, identified through the latest 3rd party building inspection. Other investments entail minor upgrades and refurbishment to support health and safety of Entegrus' staff and those visiting Entegrus' offices.

The HVAC systems servicing the Chatham facility are currently a mix of aged heat pumps and baseboard heating. Installation of contemporary equipment and conversion away from the electrical heat is expected to provide Entegrus with sustainable OM&A savings. The St. Thomas building modifications will enable the reduction of Entegrus' overall facilities footprint per employee and support the operational efficiencies gained from the closure of the previously leased Strathroy facility, once this lease expires in 2022.

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.

4.4.5.5.3 Rolling Stock

This program includes the costs of repair and replacement of Entegrus' fleet of vehicles and other specialized mobile equipment. Asset renewal decisions follow the lifecycle management methodology for the appropriate vehicle class discussed in Section 3.3.5. Given the physical span of Entegrus' service territory, it is imperative that its fleet remains in optimal 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.

4.4.5.5.4 IT Hardware

This program covers the costs of all physical equipment and infrastructure required to maintain and improve Entegrus' 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 Entegrus 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 Entegrus may explore and adopt in the coming years.

Entegrus manages its IT hardware assets in accordance with a standard Lifecycle Management Policy discussed in Section 3.3.3. 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, Entegrus attempts to pace its expenditures to maintain a consistent spending profile over time.

4.4.5.5.5 IT Software

The software program includes the licensing costs of new and existing software solutions used by Entegrus 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, Entegrus maintains several sophisticated utility-specific solutions, such as those supporting the Metering, Customer Care and Billing, Control Centre, and Asset Management functions, among others. As noted in Section 3.3.3, Cybersecurity is a major priority and Entegrus is actively monitoring and managing any potential vulnerabilities within its software portfolio. Over the Forecast Period, major software expenditure priorities are expected to include:

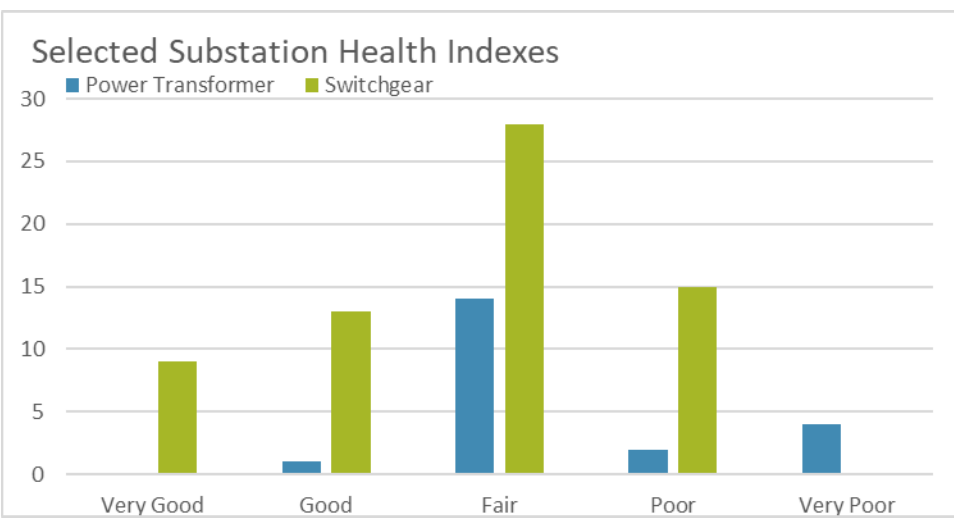
- A major version upgrade to our Customer Information System - Northstar
- Additional components for Survalent to provide outage management capabilities within SCADA
- Redevelopment of our Sharepoint Intranet with particular focus on the Health & Safety document sharing and employee learning and testing modules.

4.4.5.5.6 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 Entegrus' 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. As Figure 4-8 showcases, the condition of Entegrus' substation transformers and switchgear varies between "Very Good" through "Very Poor", with the transformers themselves being generally in worse condition. It is Entegrus' intention to decommission all of its substation infrastructure before any major components require replacement. Over the 2021-2025 plan period, Entegrus expects to decommission 5 step-down substations.

Figure 4-8: Transformer Station Health Indexes



In decommissioning the substations, Entegrus 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 without increasing the overall budgetary envelope. Another benefit will be a reduction in the need to stock older vintage station replacement parts.

There are no viable alternatives to decommissioning the stations once the downstream feeders are converted to the 27.6 kV voltage and make the station redundant. 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.

The Step-Down Transformer Reduction program corresponds to Entegrus' Safety, Sustainable Growth, Customer and Community Focus and Cost Effectiveness Planning Objectives, and Customer Focus and Operational Effectiveness RRF outcomes.

4.4.6 Capital Projects, Appendix 2-AA

Applicants must also provide a completed Chapter 2 Appendix 2-AA along with the following information about capital expenditures on a project-specific basis:

• Explanation of variances by project or category, including that of actuals versus the OEB-approved amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP, if available

• For capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress

A statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget.

Table 4-55: Appendix 2-AA

Line No.	Description	Actual					Plan				
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	**SYSTEM ACCESS**										
2	Commercial and Industrial Rebuild	$347	$659	$441	$624	$301	$327	$333	$340	$347	$354
3	Contributed Capital	-$1,501	-$1,944	-$1,454	-$3,357	-$2,726	-$3,367	-$2,300	-$2,356	-$2,413	-$2,471
4	Customer Conns: Commercial & Industrial	$274	$715	$613	$755	$788	$106	$108	$110	$112	$114
5	Customer Conns: Residential & Subdivision	$1,144	$1,275	$1,818	$2,221	$2,915	$3,753	$2,562	$2,604	$2,191	$2,235
6	Delta - Wye Service Conversions	$0	$0	$0	$126	$33	$253	$100	$80	$60	$0
7	Edgeware Capacity Enhancements	$0	$0	$0	$0	$0	$0	$0	$1,700	$0	$0
8	Engineering Support Capital	$649	$860	$666	$782	$1,028	$765	$780	$796	$812	$828
9	Miscellaneous System Access	$555	$406	$342	$252	$415	$77	$79	$81	$82	$84
10	Third Party Attachments	$0	$0	$290	$959	$767	$587	$346	$300	$306	$312
11	**Subtotal**	**$1,468**	**$1,970**	**$2,715**	**$2,362**	**$3,519**	**$2,499**	**$2,008**	**$3,654**	**$1,496**	**$1,455**
12	**SYSTEM RENEWAL**										
13	Critical Defect Replacements	$524	$120	$168	$276	$243	$322	$375	$383	$391	$378
14	Emergency Response	$185	$528	$964	$497	$727	$457	$466	$475	$485	$494
15	Metering Renewal	$658	$987	$897	$1,087	$1,245	$1,394	$1,556	$1,587	$1,619	$1,632
16	Miscellaneous System Renewal	$367	-$227	$0	$7	$135	$146	$149	$152	$155	$158
17	Operation Support Capital	$552	$630	$825	$1,035	$897	$776	$791	$807	$823	$840
18	Pole Replacement	$217	$110	$483	$402	$933	$506	$586	$597	$609	$622
19	Transformer Replacement	$353	$157	$40	$100	$147	$436	$445	$428	$436	$445
20	Voltage Conversion	$2,769	$1,730	$1,141	$1,189	$1,794	$3,201	$3,301	$3,443	$4,862	$4,827
21	**Subtotal**	**$5,624**	**$4,035**	**$4,518**	**$4,592**	**$6,121**	**$7,238**	**$7,669**	**$7,872**	**$9,380**	**$9,395**
22	**SYSTEM SERVICE**										
23	Metering Upgrades	$67	$31	$80	$123	$84	$65	$66	$68	$69	$70
24	Miscellaneous System Service	$0	$0	$0	$0	$116	$102	$94	$96	$98	$100
25	System Automation	$346	$59	$306	$304	$517	$110	$142	$145	$1,085	$643
26	System Modernization and Planning	$501	$1,577	$827	$796	$1,014	$436	$537	$548	$559	$570
27	System Reinforcement	$0	$0	$0	$0	$0	$350	$128	$131	$133	$136
28	**Subtotal**	**$914**	**$1,667**	**$1,213**	**$1,223**	**$1,731**	**$1,063**	**$968**	**$987**	**$1,944**	**$1,519**
29	**GENERAL PLANT**										
30	Building	$199	$186	$525	$832	$747	$176	$199	$203	$207	$211
31	IT Hardware	$246	$386	$565	$199	$335	$160	$235	$240	$235	$255
32	IT Software	$305	$430	$386	$676	$535	$320	$315	$320	$325	$310
33	Miscellaneous General Plant	$38	$17	$117	$17	$62	$305	$247	$200	$207	$205
34	Rolling Stock	$305	$990	$262	$560	$52	$805	$841	$908	$925	$943
35	Tools	$252	$139	$118	$100	$74	$209	$213	$217	$222	$226
36	**Subtotal**	**$1,345**	**$2,148**	**$1,973**	**$2,383**	**$1,805**	**$1,974**	**$2,051**	**$2,088**	**$2,121**	**$2,150**
37	**GRAND TOTAL**	**$9,351**	**$9,820**	**$10,420**	**$10,559**	**$13,176**	**$12,775**	**$12,696**	**$14,601**	**$14,942**	**$14,520**

4.5 JUSTIFYING CAPITAL EXPENDITURES & OVERALL PLAN (5.4.3 / 5.4.3.1)

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures. A distributor should also keep pace with technological changes and integrate cost-effective innovative projects and traditional planning needs such as load growth, asset condition and reliability.

The OEB's assessment of DSPs includes the costs of material projects/programs included in the DSP, as well as how the overall DSP budget is allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.3.2.

To support the overall quantum of investments included in a DSP by category, a distributor should include information on:

a) Comparative expenditures by category over the historical period

b) The forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts

c) The drivers of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3)

d) Information related to the distributor's system capability assessment (see section 5.3.4)

4.5.1 Capital Expenditures by Category (5.4.3.1a)

Comparative expenditures by category over the historical period

4.5.1.1 System Access

Actual expenditures for System Access started to grow in 2017 and then showed consistent and unprecedented growth, particularly through 2020 and 2021. Among the programs in this investment category, Residential and Subdivision customer connections have been the leading contributor to the total annual investments.

As displayed in the Figure below, the Forecast Period projection declines starting in 2022. In the design phase of this DSP, it was anticipated that due to the pandemic, the System Access would be even lower – and would decline to lower than Historical Period levels in 2022-2025. This expectation was reinforced when many developers put System Access requests on hold between March 2020 and June 2020. However, when Ontario pandemic restrictions eased in the summer of 2020, growth surged again, particularly in St. Thomas, Strathroy, Mount Brydges and Chatham. This surge has continued into September 2021, such that management updated this DSP filing to adjust 2022-2025 System Access by an aggregate increase of $3M prior to filing of this DSP in September 2021, in order to reflect a more moderate growth outlook. This moderate growth outlook remains consistent with the anticipated end of pandemic-related housing trends, as well as constraints to the supply of available development land within established service territory boundaries. The revised figures are shown in the chart below.

An additional notable item is that System Access includes a significant a 2023 investment for a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas in 2023 as discussed in Section 4.2.1 and Section 4.2.2.

Figure 4-9: System Access Comparative Expenditures

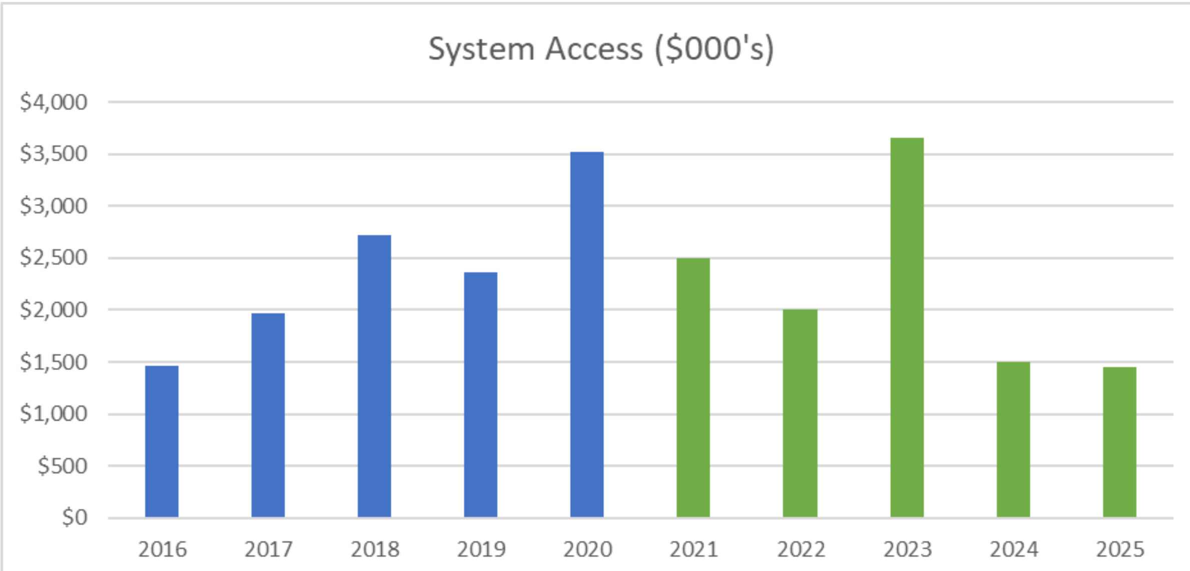
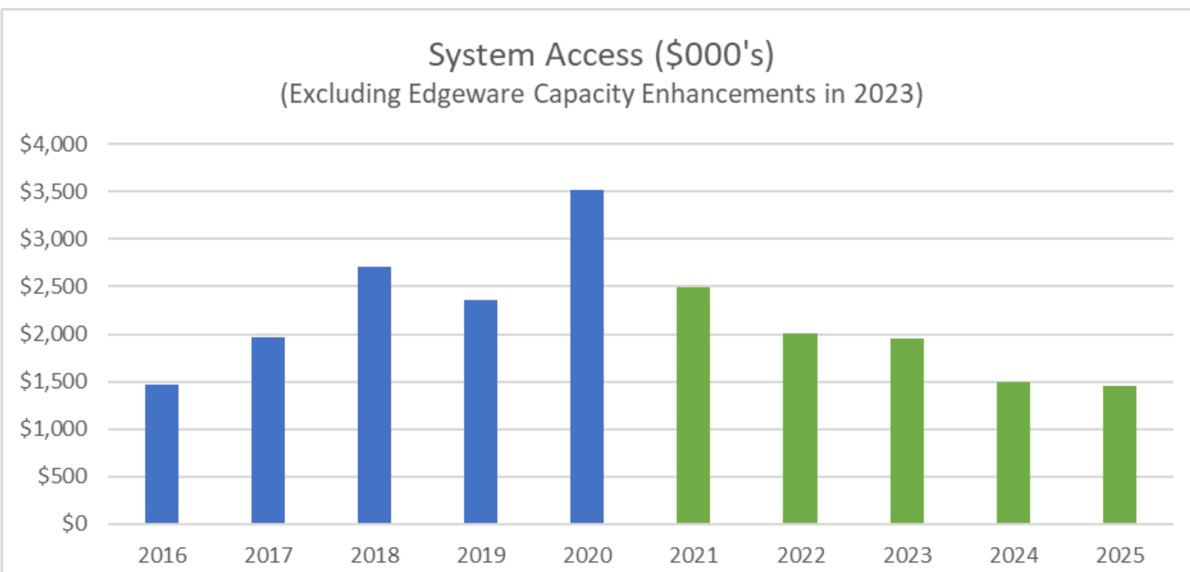


Figure 4-10: System Access Adjusted Comparative Expenditures

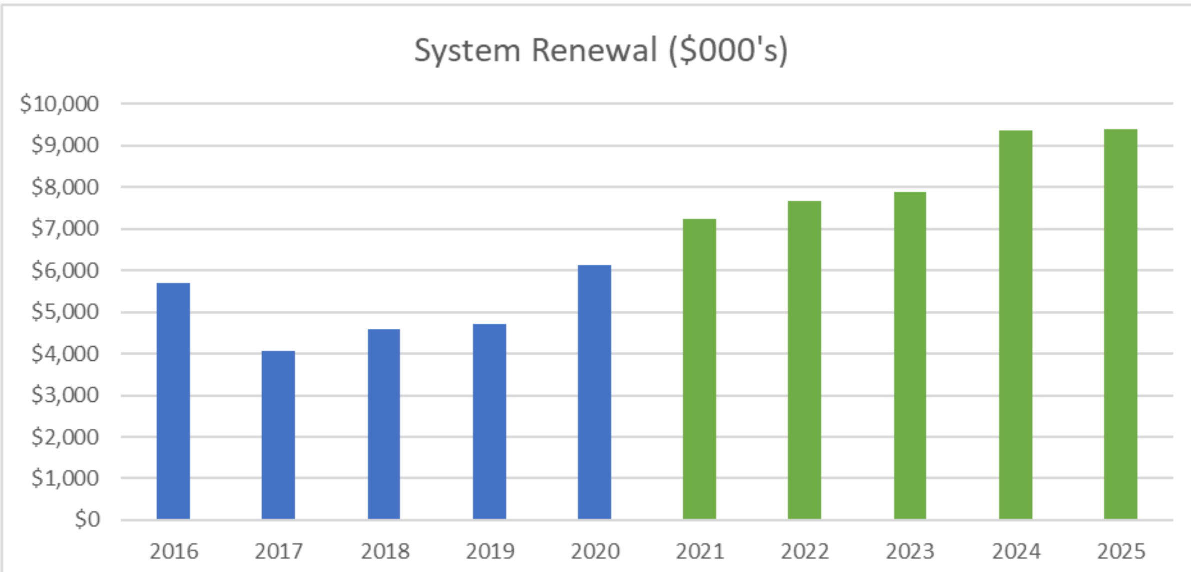


4.5.1.2 System Renewal

Actual expenditures for System Renewal over the Historical Period were lower than planned. A key contributor to the relatively lower System Renewal expenditures, particularly in 2017-2019, was the deferral of voltage conversion that occurred in 2017 to 2019. This occurred in order to facilitate the unanticipated customer growth levels and corresponding investment and manpower needed in the System Access investment category (see above).

As seen in Figure 4-11, the System Renewal forecast average is approximately 50% greater than the historical average, as more fully described in Section 1.5.1. In addition, the customer engagement process showed a preference for Entegrus to conduct additional voltage conversion work in the Forecast Period. These additional planned capital expenditures are included in the 2024 and 2025 forecast and are described in more detail in Section 4.1.3.2.

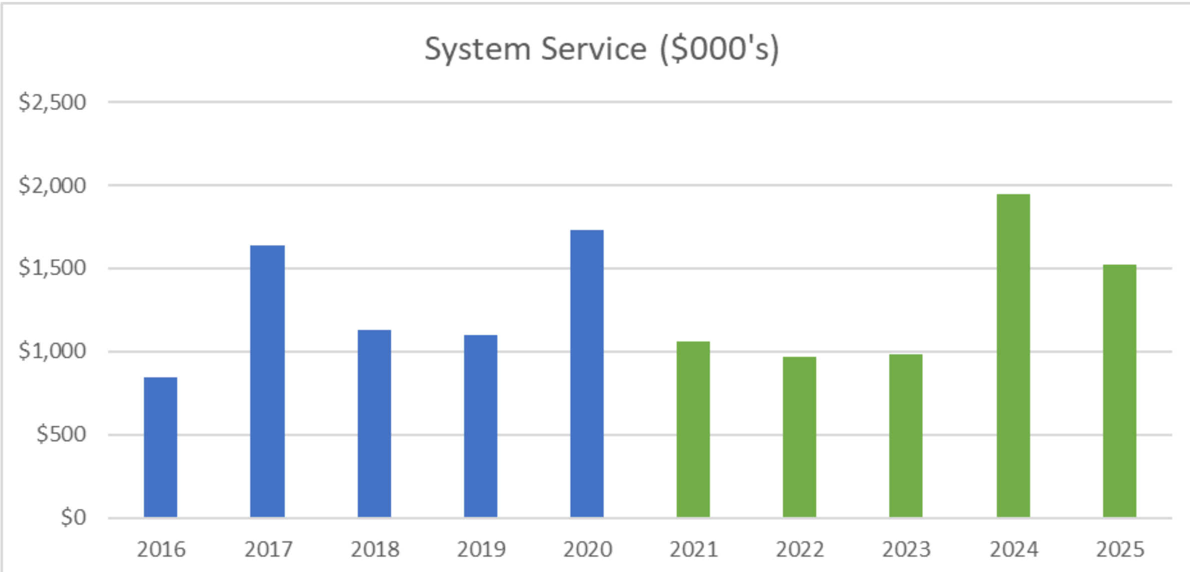
Figure 4-11: System Renewal Comparative Expenditure



4.5.1.3 System Service

Actual expenditures for System Service investments are relatively consistent going into the Forecast Period. As noted in Section 4.4.4.6.3, the 2020 increase was a result of sectionalization (automated switching project) on the M21 in Chatham, which demonstrating the benefits of automated switching. The customer engagement process showed a preference for Entegrus to install additional automated switches in Chatham and St. Thomas to create a dynamic distribution grid. These additional planned capital expenditures are included in the Forecast Period and drive the 2024/2025 increases shown in the figure below. These projects are described in more detail in Section 4.1.3.2

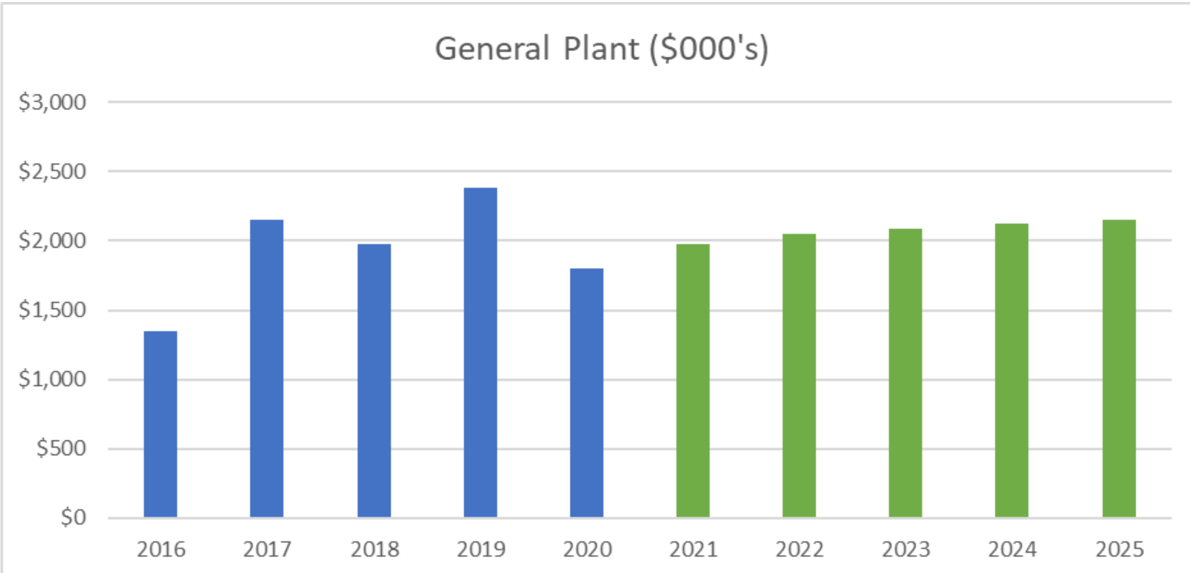
Figure 4-12: System Renewal Comparative Expenditure



4.5.1.4 General Plant

Actual expenditures for General Plant investments followed an increasing trend in 2019 and remain generally consistent moving through the forecast years. The 2019 increase to $2.4 million is the high watermark amongst the historical and forecast years. This was driven by the merger, and more specifically building upgrades (primarily in St. Thomas) and software costs to integrate and merge Northstar CIS data between the St. Thomas and Chatham offices. The forecast years have relatively consistent investments levels ranging from $1.7 million to $1.8 million. Historical average expenditures slightly outweigh the forecast average by 4% as seen in Figure 4-13.

Figure 4-13: General Plan Comparative Expenditure



4.5.2 Impact on System O&M Costs (5.4.3.1b)

The forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts

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 DS c/w transformer, switchgear, land, etc.) will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs.

Relocation/replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the Distribution system Code). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact on O&M repair related charges. Overall, the planned system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end of life plant with new plant will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) 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 equipment class average condition then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on positive growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall, this is expected to put downward pressure on O&M repair related costs.

System support expenditures (e.g. GIS, Asset Condition Assessment studies) are expected to provide a better overall understanding of the assets that will lead to more efficient and optimized design, maintenance and investment activities going forward. Asset Condition Assessment studies have been conducted and data gaps have been identified. To improve the quality of data used in the ACA studies, increased data collection efforts will be required which will increase pressure on O&M costs. Collected data will be input into the GIS as attribute information for each piece of plant. Improved asset information will allow existing resources to partially compensate for growth related increases in O&M activities. Fleet replacement expenditures will result in reduced O&M for new units – however, this will be offset by increasing O&M of remaining units as they get older. Overall, the system investments are not expected to have a significant impact on total O&M costs in the Forecast Period.

The paced 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 without increasing the overall budgetary envelope. Another benefit will be a reduction in the need to stock older vintage station replacement parts.

4.5.3 Investment Drivers by Category (5.4.3.1c)

The drivers of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3)

4.5.3.1 System Access

System Access investments include the following drivers:

- Anticipated new residential subdivisions across growing Entegrus communities, particularly due to the high residential growth in St. Thomas, as well as higher growth Northeast region communities of Strathroy and Mt. Brydges – and more recently, Southwest region communities such as Chatham (which is experiencing an "out-migration" trend whereby former residents of the GTA relocate to Chatham). In addition, System Access also includes a 2023 investment for a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas in 2023 as discussed in Section 4.2.1 and Section 4.2.2;

- Anticipated connection of new customer premises or upgrades/modifications to existing facilities to accommodate changing capacity needs or other customer requests;

- Relocation of utility infrastructure driven by requests from provincial, regional, municipal, or private sector entities;

- "Fibre to the Home" projects, driven by multiple fibre companies expanding their networks, which requires Entegrus engineering studies, make-ready work and often asset replacements (which are partially offset by capital contributions); and

- Investment in a new supply feeder and associated breaker position at the Edgeware station (TS) in St. Thomas in 2023.

4.5.3.2 System Renewal

System Renewal investments include the following drivers:

- Proactive and reactive replacement of aged and degraded distribution infrastructure, including replacement of assets that have reached end of useful life through asset management planning and/or field inspection work and which is contributing to the recent deterioration in reliability measures;

- Conversion of deteriorated low-voltage overhead and underground feeders to modern 27.6 kV infrastructure designed to latest technical and safety standards. Customer engagement indicated a customer preference for a faster pace of conversion, which has been incorporated into this DSP;

- Life extension work is also required and occurring on some legacy low-voltage substations while conversion work is ongoing; and

- Ongoing refresh of Advanced Metering Infrastructure (AMI) assets and a paced replacement of customer smart meters on a rolling community basis at the end of their re-seal periods with one harmonized smart meter system, along with associated communication equipment and the lifecycle replacement of core infrastructure such as gateways and servers.

4.5.3.3 System Service

System Service investments include the following drivers:

- The creation of additional capacity through re-conductoring and additional tie points between feeders to increase system resiliency, particularly in the northeast region, and allow for greater operational flexibility;

- Construction of new feeder ties in multiple locations to reduce outage instances experienced by Entegrus customers, as well as sectionalization and distribution automation to allow for automatic restoration implementation. Customer engagement indicated a customer preference for additional automated switch investment in Chatham and St. Thomas, which has been incorporated into this DSP; and

- Ongoing support of the Chatham-based Control Room and continued enhancements to its Asset Management and field inspection capabilities.

4.5.3.4 General Plant

General Plant investments include the following drivers:

- Investments in Hyperconverged IT Infrastructure, Data Storage and Cybersecurity to improve the operating efficiency and security of customer data, which continues to support the recent enhancements to the GIS system and digital modernization of the Control Room;

- Facilities investments to modernize the core building systems in Chatham and facilitate the closure of the Strathroy operating centre in 2021 Q4 and its integration into the St. Thomas operating centre, as more fully described in Section 3.3.4; and

- Lifecycle-based replacement of vehicles and tools and implements that enable Entegrus staff to perform their regular tasks safely and reliably.

4.5.4 Capability Assessment (5.4.3.1d/5.3.4)

A distributor's investments to accommodate and connect REG (including connection assets, expansions and/or renewable enabling improvements) are integral to its DSP. This includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the Ontario Energy Board Act, 1998. REG investments can be stand-alone or integrated into a project/program; and are to be categorized for the purposes of section 5.4 in the same way as any other investment.

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application.

a) Applications from renewable generators over 10 kW for connection in the distributor's service area

b) The number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the IESO and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown must be provided)

c) The capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area

d) Constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter)

e) Constraints for an embedded distributor that may result from the connections

4.5.4.1 Applications for Renewable Generators over 10 kW (5.3.4a)

Please refer to Section 4.3.1.3.

4.5.4.2 Forecasted Renewable Generation Connections (5.3.4b)

Please refer to Section 4.3.1.3.

4.5.4.3 Capacity to Connect Renewable Generation (5.3.4c)

Please refer to Table 4-16.

4.5.4.4 Constraints to Connect Renewable Generation (5.4.3d)

There are currently no constraints related to the connection of renewable generation within the distributor's system or upstream transmitter.

4.5.4.5 Constraints to Embedded Distributor (5.4.3e)

There are currently no constraints for the embedded distributor to accommodate the connection of renewable generation.

4.5.5 Material Investments (5.4.3.2)

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project/program should be proportional to the materiality of the investment.

The focus on this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements and further detailed earlier in this document. For detailed information regarding these projects, please see Attachment O.System Access

Table 4-56: 2021-2025 System Access Prioritization

Line No.	Description	2021	2022	2023	2024	2025	Priority Ranking
1	Commercial and Industrial Rebuild	$327	$333	$340	$347	$354	13
2	Contributed Capital	-$3,367	-$2,300	-$2,356	-$2,413	-$2,471	-
3	Customer Conns: Commercial & Industrial	$106	$108	$110	$112	$114	9
4	Customer Conns: Residential & Subdivision	$3,753	$2,562	$2,604	$2,191	$2,235	10
5	Delta - Wye Service Conversions	$253	$100	$80	$60	$0	22
6	Edgeware Capacity Enhancements	$0	$0	$1,700	$0	$0	12
7	Engineering Support Capital	$765	$780	$796	$812	$828	4
8	Miscellaneous System Access	$77	$79	$81	$82	$84	23
9	Third Party Attachments	$587	$346	$300	$306	$312	11
10	**Total System Access**	**$2,499**	**$2,008**	**$3,654**	**$1,496**	**$1,455**	

4.5.5.1 System Renewal

Table 4-57: 2021-2025 System Renewal Prioritization

Line No.	Description	2021	2022	2023	2024	2025	Priority Ranking
1	Critical Defect Replacements	$322	$375	$383	$391	$378	2
2	Emergency Response	$457	$466	$475	$485	$494	1
3	Metering Renewal	$1,394	$1,556	$1,587	$1,619	$1,632	20
4	Miscellaneous System Renewal	$146	$149	$152	$155	$158	21
5	Operation Support Capital	$776	$791	$807	$823	$840	3
6	Pole Replacement	$506	$586	$597	$609	$622	14
7	Transformer Replacement	$436	$445	$428	$436	$445	15
8	Voltage Conversion	$3,201	$3,301	$3,443	$4,862	$4,827	26
9	**Total System Renewal**	**$7,238**	**$7,669**	**$7,872**	**$9,380**	**$9,395**	

4.5.5.2 System Service

Table 4-58: 2021-2025 System Service Prioritization

Line No.	Description	2021	2022	2023	2024	2025	Priority Ranking
1	Metering Upgrades	$65	$66	$68	$69	$70	16
2	Miscellaneous System Service	$102	$94	$96	$98	$100	25
3	System Automation	$110	$142	$145	$1,085	$643	27
4	System Modernization and Planning	$436	$537	$548	$559	$570	5
5	System Reinforcement	$350	$128	$131	$133	$136	24
6	**Total System Service**	**$1,063**	**$968**	**$987**	**$1,944**	**$1,519**	

4.5.5.3 General Plant

Table 4-59: 2021-2025 General Plant Prioritization

Line No.	Description	2021	2022	2023	2024	2025	Priority Ranking
1	Building	$176	$199	$203	$207	$211	8
2	IT Hardware	$160	$235	$240	$235	$255	6
3	IT Software	$320	$315	$320	$325	$310	7
4	Miscellaneous General Plant	$305	$247	$200	$207	$205	17
5	Rolling Stock	$805	$841	$908	$925	$943	18
6	Tools	$209	$213	$217	$222	$226	19
7	**Total General Plant**	**$1,974**	**$2,051**	**$2,088**	**$2,121**	**$2,150**	