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June 30, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-20147 – In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned proceeding, please find **Consumers Energy Company's Final Electric Distribution Infrastructure Investment Plan ("EDIIP") 2021-25**.

Consumers Energy files this Final EDIIP 2021-2025 in accordance with the Commission's August 20, 2020 Order in this case, which required the Company to file its initial draft plan by August 1, 2021, and to file its final plan by September 30, 2021. Consumers Energy filed its initial draft EDIIP on April 30, 2021. The Company is filing this final EDIIP today to coincide with the filing of its Integrated Resources Plan in Case No. U-21090. In filing its Final EDIIP today, the Company maintains the same number of days between the initial and final filings as set forth in the Commission's August 20 Order.

This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Michael C. Rampe
Digitally signed by Michael C. Rampe
Date: 2021.06.30 08:29:19 -04'00'

Michael C. Rampe

Electric Distribution Infrastructure Investment Plan (2021-25)

June 30, 2021

I. Executive Summary

Consumers Energy Company (“Consumers Energy” or “the Company”) is driven by its purpose to achieve world-class performance delivering hometown service, measured by a triple bottom line – people, the planet, and Michigan’s prosperity. The triple bottom line balances the interests of customers with other stakeholders and captures the broader societal impacts of the Company's activities. The triple bottom line allows the Company to balance the interests of all those who count on it – not at the expense of one another – and is essential to its success now and in the future.

> *People* – The Company is committed to its customers, employees, and every Michigan resident. Central to this commitment is providing safe, reliable, and affordable electric service. The Company’s commitment to people also means providing customers with a great customer experience – what employees at Consumers Energy refer to as providing hometown service.
>
> The Company is focused on the best solution for all the people of Michigan. Based on grid needs and customer usage, the Company determines the most efficient resources to deploy including central, distributed, or demand-side resources. In order to achieve the best solution for all, rate design should be technology agnostic and protect customers from cross-subsidization.
>
> *Planet* – Consumers Energy is committed to reduce 90% of the carbon emissions it generates by eliminating the use of coal and working with customers to use energy more efficiently. The Company has also announced that it will take that goal a step further, committing to achieve net zero carbon emissions by 2040. Consumers Energy is proud to forge a path into a cleaner, more sustainable energy future.
>
> *Michigan’s Prosperity* – Consumers Energy is committed to Michigan’s prosperity. A prosperous Michigan cannot exist without a financially healthy utility that provides safe, reliable, affordable, and increasingly clean energy. The significant funding the Company receives each year from investors and lenders make the electric system infrastructure replacements and enhancements that benefit our customers and the state of Michigan possible. Ensuring Michigan’s prosperity also includes investing in our local communities and supporting local nonprofits in addition to helping Michigan businesses grow.

The Company has proudly served Michigan families and businesses since 1886, with over 1.9 million electric customers across the state today. The Company is committed to providing an electric distribution system that delivers safe, reliable, and affordable electricity to customers today and in the future. To do that, the Company must address infrastructure issues in the near-term while adapting to meet evolving customer expectations and technology advancements. The Company’s distribution strategy is based on five customer-focused objectives:

- **Safety and Security:** Improving overall safety and security for customers and employees;
- **Reliability:** Improving system reliability under normal operating conditions and resiliency under extreme conditions;
- **System Cost:** Delivering the objectives above at an optimal, long-term system cost for all customers;
- **Sustainability:** Continuing to look for opportunities to explore sustainable options and reduce system waste; and

- **Control:** Providing customers with the data, technology and tools to take greater control over their energy supply and consumption.

The Michigan Public Service Commission ("MPSC" or "the Commission") first directed the Company to submit a five-year electric distribution investment plan in a 2017 Order. (February 28, 2017 Order in Case No. U-17990.) On March 1, 2018, the Company delivered its first Electric Distribution Infrastructure Investment Plan ("EDIIP"), meeting the MPSC's directive. Since then, the Company has collaborated with MPSC Staff and other stakeholders in various arenas to further develop approaches to multi-year distribution planning. The MPSC has issued three subsequent Orders in Case No. U-20147 directing the Company to file this second EDIIP in 2021 and providing considerable guidance on new and revised content for inclusion in this plan.

During the three years since the 2018 EDIIP filing, the Company has increased investment in the electric distribution system, with particular focus on reliability improvements, and the Company proposes continued increases in key investment areas over the next five years in this 2021 EDIIP. Over the past three years, the Company has improved its ability to discern asset deterioration on the distribution system, and mitigating the reliability impacts of that asset deterioration is a key consideration in this five-year plan.

During the past three years, the Company has continued investment in Grid Modernization efforts and developed a new Grid Modernization Roadmap leading to the longer-term vision of the future grid. This longer-term vision is increasingly important as the Company's Integrated Resource Plan ("IRP") process has, since 2018, pointed to a future with considerably more decentralized energy resources, such as solar, as part of the Company's electric supply mix.

The Company is developing other new grid-related capabilities as well. For example, the Company has been studying potential applications of non-wires solutions ("NWS"), building the Company's ability to perform hosting capacity analyses ("HCA") on distribution circuits, and exploring various new applications for battery storage.

Highlights of this 2021 EDIIP include:

- **A Vision for the Consumers Energy Electric Distribution System**: The electric distribution system is on the cusp of a period of change, as new technologies and decentralization of the grid are set to disrupt the historical hub-and-spoke model. Even as the grid changes, the Company's distribution strategy will remain customer-focused, as expressed by the five distribution objectives.
    - The Company will pursue these objectives through its long-term electric strategy that focuses on two key concepts – **excelling at the basics** and **building for the future** (i.e., modernizing the electric grid);
    - To support these objectives, the Company has defined 14 metrics to track and manage performance, creating a balanced and holistic framework underpinning investment decisions; and
    - To further promote accountability regarding reliability performance, the Company is introducing a proposed performance-based ratemaking ("PBR") framework around two reliability metrics.

- **An Overview of Distribution System Performance**: The Company monitors its distribution system performance through a suite of reliability metrics, which are tracked on a systemwide, regional, and local level to provide visibility into areas of the grid with the most pressing needs. Key metrics are benchmarked against peer utilities. The Company has charted a five-year glidepath for improvement in reliability performance.

- **An Approach to Investment Planning**: The five-year plan outlined in this EDIIP is a result of a planning process designed to prioritize and sequence investments to meet system needs and deliver benefits to customers. The Company uses a multi-faceted approach to identifying and prioritizing projects to maximize customer benefits and ensure that customer benefits are equitable throughout Michigan.

- **Grid Modernization and Longer-Term View of the Grid**: Since the 2018 EDIIP was filed, the Company has made significant progress in Grid Modernization, deploying devices on the grid, and enabling grid automation. The Company has evaluated the likely future of the grid over the next 10 to 15 years, identified technological gaps between the current state of the grid and what is needed for that future, and developed a comprehensive Grid Modernization Roadmap to close those gaps on multiple time horizons.

- **Integrated Planning**: Development of this EDIIP was concurrent with development of the Company's 2021 IRP, allowing ongoing internal collaboration on the two plans. Further integration of planning is expected in the next few years, and the Company has already taken steps to meaningfully align distribution planning and electric supply planning.

- **Emerging Topics**: Following collaboration with stakeholders and direction from the MPSC, the Company has developed a multi-year "trail map" to build on lessons learned in NWS pilots and explore how to scale NWS to become standard grid solutions to grid issues. The Company is also phasing in an HCA of its distribution system.

- **A Summary of Five-Year Plan (Capital and Operating and Maintenance ("O&M"))**: Over the five-year period from 2021 through 2025, the Company plans to invest between $708 million and $865 million per year in capital projects on the electric distribution system. The largest driver of increased capital investment is in the Reliability capital program. Over the same period, the Company plans O&M spending between $221 million and $308 million per year, with increases driven by deliberate increases in Forestry work, increased inspection, and maintenance activity, and hiring to facilitate increased distribution workloads related to increased reliability investments to meet customer expectations.

FIGURE 1
SUMMARY OF FIVE-YEAR ELECTRIC SPENDING PLAN

5-Year Plan									
All values in $ millions		Actual			Plan				
		2018	2019	2020 prelim	2021	2022	2023	2024	2025
Capital Programs									
Capital	New Business	105.1	132.6	119.5	140.1	134.2	143.8	147.7	151.7
	Demand Failures	144.8	174	149.1	124.4	127.6	130	131.9	138.8
	Asset Relocations	40.5	43.7	39.9	53.7	57.4	60.9	64.1	67
	Total Unplanned	290.4	350.3	308.5	318.1	319.5	334.7	343.7	357.5
	Reliability	155.5	196.3	199	312.2	369.4	415.7	412.6	420.2
	Capacity	58.2	57.3	57.8	58.6	60.3	75.8	78.6	77.8
	Electric "Other"	4.9	6.4	7.7	15.7	14.8	15	13.7	14.1
	Total Planned	218.6	260	264.5	386.5	444.5	506.5	504.9	512.1
	Capital Plan	509	610.3	573	704.6	764	841.2	848.6	869.6
O&M Programs									
O&M	Forestry	51.9	53.3	54.8	84	94.4	100	117.6	120.4
	Service Restoration	53.9	92.1	65.3	47.3	74.3	74.3	74.3	74.3
	Other O&M	85.4	84	75.1	90.1	106.5	108.1	112.6	113.1
	O&M Plan	191.2	229.4	195.2	221.4	275.2	282.4	304.5	307.8

Through this EDIIP, the Company presents its future vision for the electric distribution system, analyzed through the lens of the current state of the system, and outlines an investment plan to bridge the current and future states. The Company looks forward to working with the MPSC, Staff, and the broader set of stakeholders as this plan is executed and evolves over time.

II. Framing

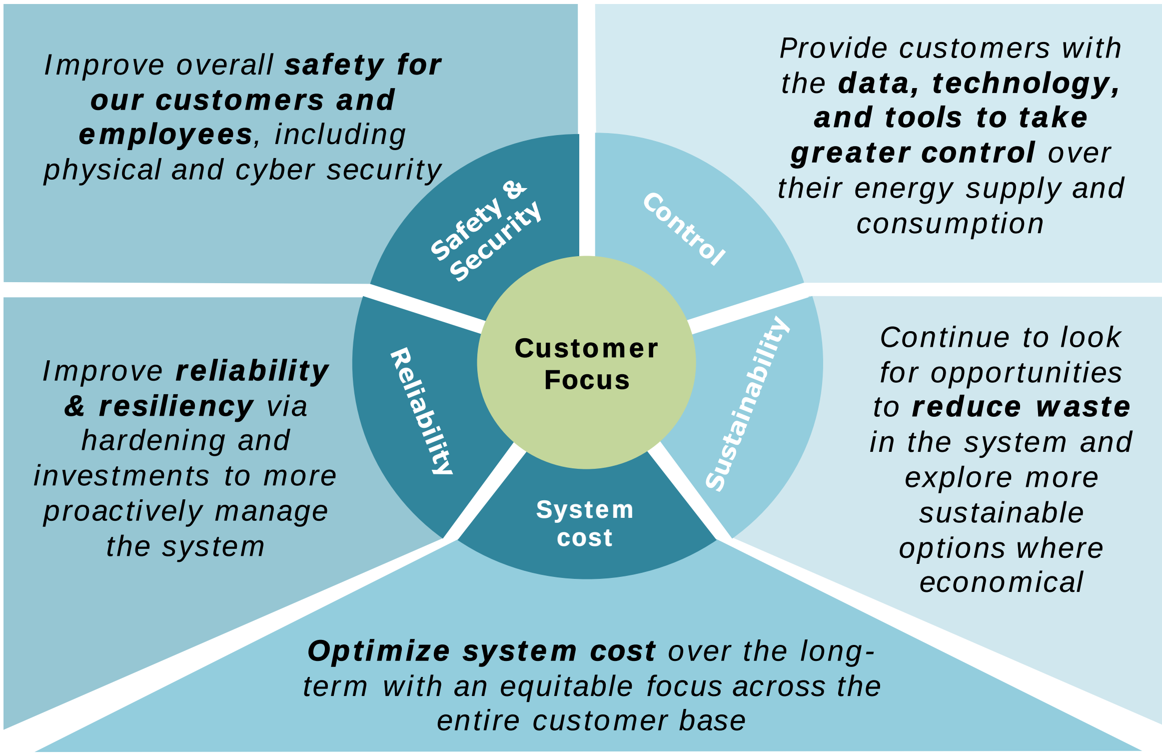
A. Objectives

The electric distribution system – both the specific system owned by the Company and the broader system across the United States – is in a period of great change, as technological advances and other innovations allow customers to manage their electricity usage in new ways and as customer expectations evolve. Customers continue to expect electricity to be delivered safely and reliably and in a cost-effective manner, and many customers increasingly also expect more control over their energy usage and more sustainable sources of electricity.

The Company is committed to building a modern electric distribution system that integrates cleaner, more distributed sources of electric supply with grid enhancements engineered for customer value. More specifically, this EDIIP focuses on meeting five primary customer-focused objectives:

FIGURE 2

VISION FOR THE CONSUMERS ENERGY ELECTRIC DISTRIBUTION GRID



- **Enhance cybersecurity, physical security, and safety** – The Company designs its distribution system to ensure that the security and safety of customers – and employees – is maintained and ultimately enhanced;

- **Improve reliability and resiliency** – The Company will harden the system, where necessary; improve visibility in order to more proactively operate the system; minimize outage occurrences; respond with speed and effectiveness to minimize outage duration; and better manage frequency and voltage;

- **Optimize system cost over the long term** – The Company will meet its objectives in a manner that is most cost-effective and equitable for the entire customer base over the long term. The Company will not optimize costs for some customers in a manner that unfairly impacts other customers and will not be short-sighted by minimizing cost in the short term only to bear a multiple of that cost in later years;

- **Increase sustainability and reduce waste in the system** – The Company will look for opportunities to reduce waste in the system by building "at the right size and at the right time" (e.g., smaller, more modular, and more targeted investments) and exploring opportunities to promote lower carbon resources where economical; and

- **Enable greater control** – The Company will continue to configure the system to provide customers with the data, technology, and tools to take greater control over their energy supply and consumption.

The Company will pursue these objectives through its long-term electric strategy that focuses on two key concepts – **excelling at the basics** and **building for the future** (i.e., modernizing the electric grid).

When considering the electric distribution system, "excelling at the basics" consists of investment in and maintenance of core traditional infrastructure, like poles, wires, and substations. "Building for the future" consists of enabling the transition to cleaner energy resources, including integration of distributed energy resources ("DERs"), and increasing automation of the system, using advanced grid technologies.

B. Metrics

i. Introduction to Metrics, Recent Performance, and Expected Performance

In the 2018 EDIIP, the Company introduced a set of 14 metrics to track the Company's distribution performance against its five distribution objectives in a holistic way. In addition to these EDIIP metrics, the Company regularly tracks and reports performance against MPSC-defined performance standards for electric power reliability and service quality through annual filings and through periodic updates with MPSC Staff. The purpose of the EDIIP metrics is to go beyond the focus of those reporting requirements, creating a broad picture of distribution performance that is increasingly customer focused.

The Company evaluates and refines its EDIIP metrics over time, and while most of the 14 EDIIP metrics from 2018 are retained in this report, a few have been adjusted to reflect evolving realities, as discussed below.

The Company's 14 metrics for the 2021 EDIIP, recent historical performance, and expected performance at the end of this five-year period in 2025, are shown in Figure 3 below.

FIGURE 3

HISTORICAL PERFORMANCE ON EDIIP METRICS AND EXPECTED FUTURE PERFORMANCE

<table>
<tr><th colspan="2">Metric</th><th>2016 – 2020</th><th>2020</th><th>2025 Projection</th></tr>
<tr><td rowspan="3">Safety & Security</td><td>Recordable incident rate (for work in electric operations)</td><td>1.86</td><td>2.04</td><td>1.50</td></tr>
<tr><td rowspan="2">Wire down relief factor (% of police/fire-guarded wire downs relieved in 4 hours inside MMSAs, 6 hours outside MMSAs)</td><td>91% (inside MMSA)</td><td>90.1% (inside MMSA)</td><td rowspan="2">>90%</td></tr>
<tr><td>94% (outside MMSA)</td><td>92.5% (outside MMSA)</td></tr>
<tr><td>Reliability</td><td>SAIDI (excluding MED)</td><td>200</td><td>195</td><td>170</td></tr>
</table>

	SAIFI (excluding MED)	1.02	1.03	0.95
	% of customers with ≥5 interruptions	4.7%	4.7%	<5%
	% of customers with one or more interruption of ≥5 hours	27.7%	27.1%	24.6%
	% of customers restored within 24 hours of a MED interruption	79.6%	74.6%	81.8%
System Cost	Service restoration O&M cost per incident (three-year rolling average; including MED)	$590[1]	$721	$811
	Forestry cost per line-mile cleared	$11.3K (2017-2020)	$10.5K	$13.3K
Sustainability	Energy savings through Energy Waste Reduction programs	504 GWh	593 GWh	545 GWh
	System load factor	58%	60%	57%
	System losses	2,842K MWh *(2016-2019)*	2,909K MWh *(2019)*	2,832K MWh
Control	% residential survey respondents rating 9/10 on CE's efforts to help control usage (JDP)	25%	29%	First quartile (within statistically significant range)
	MW saved through Residential and Commercial & Industrial ("C&I") DR	297 MW	474 MW	641 MW

[1] Calculated by adding the year-end three-year rolling average for each year 2016 through 2020 and dividing by 5.

ii. Explanation of Metrics

For each of the 14 metrics in Figure 3, the Company has reviewed its performance over the past five years, calling out performance in the most recent complete year. For each metric, the Company is either setting a target for performance in 2025 – the last year of the five-year plan outlined in this EDIIP – or it is calculating expected performance in 2025 based on the investments and activities outlined in this EDIIP. In either case, establishing expectations for 2025 will allow the Company to assess its progress in meeting all five objectives.

a) Safety Metrics

The two safety metrics measure the Company's ability to safeguard both employee and public safety in operating and maintaining the distribution system.

Recordable incident rate captures the frequency of recordable safety incidents on a per-workhour basis and is a measure of employee safety. The EDIIP metric focuses on recordable incident rate within Electric Operations, the organization within the Company most responsible for direct maintenance of the system. Over the next five years, the Company expects to reduce recordable incident rate, both Company-wide and within Electric Operations, through overall efforts to continue improving safety culture. It is important to note that many recorded incidents are minor in nature, yet the Company has cultivated a culture of reporting all incidents, no matter how minor. While recording every incident can result in a higher recordable incident rate, a culture of openness means the Company has the most accurate information about employee safety. If recordable incidents are too low, that can be an indication that some incidents are not being reported, in turn creating less safe working conditions.

The wire down relief factor measures how well the Company ensures public safety and minimizes public risk by relieving police and fire departments from having to guard downed wires. Per MPSC performance standards, the Company targets relieving at least 90% of first responders within four hours within a Michigan Metropolitan Statistical Area ("MMSA") and within six hours outside of an MMSA. While this is sometimes challenging following a catastrophic storm, the Company believes that within the next few years it will be able to use a Live Wire Down Detection module in its Advanced Distribution Management System ("ADMS") to quickly locate and respond to downed wires, ensuring consistent performance on this metric.

b) Reliability Metrics

The five reliability metrics measure the Company's ability to deliver electricity to customers, by considering both systemwide performance and the experiences of individual customers.

Two metrics address systemwide performance: System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). SAIDI is an overall measure of operating and engineering performance, tracking both the frequency of interruptions and speed of service restoration. SAIFI is an overall measure of frequency of interruptions experienced by customers. SAIDI is the product of SAIFI multiplied by a third measurement, Customer Average Interruption Duration Index ("CAIDI"). The Company considers SAIDI, SAIFI, and CAIDI excluding Major Event Days ("MEDs") based on methodology in IEEE Standard 1366-2012. The IEEE Standard 1366-2012 standard defines MEDS based on five sequential years of daily outage minutes to set a threshold for extraordinary weather events. When the MED threshold is exceeded in a 24-hour period, all reliability metrics from outages initiated in that timeframe are excluded from the totals. The purpose of excluding MEDs is to ensure the correct comparison of performance across time while excluding significant anomalies caused by major weather events on the system.

The Company has calculated a glidepath for SAIDI and SAIFI improvement, with corresponding CAIDI improvements included, as shown in Figure 4 below, working from a baseline established in late 2020.

FIGURE 4

RELIABILITY PERFORMANCE GLIDEPATH

	Baseline	2021	2022	2023	2024	2025
SAIFI (incidents)	1.010	1.001	0.989	0.975	0.962	0.949
CAIDI (minutes)	196	194	191	188	184	179
SAIDI (minutes)	198	194	189	183	177	170

These improvements have been modeled based on various planned investments and activities in this five-year plan targeted to improve SAIFI and CAIDI, as illustrated in Figure 5 and Figure 6 below. These investments and activities are described throughout this report.

FIGURE 5

SAIFI GLIDEPATH BY INVESTMENT/ACTIVITY AREA

Program/Sub-program	Investment Category	2021	2022	2023	2024	2025
Forestry		(0.006)	(0.011)	(0.017)	(0.023)	(0.028)
LVD Lines Rehabilitation	Security Assessment Repairs	0.001	0.000	0.000	0.002	0.005
LVD Lines Reliability	Targeted Circuit Improvements	(0.002)	(0.004)	(0.008)	(0.012)	(0.017)
	LVD Pole Replacements	0.003	0.005	0.006	0.008	0.010
Grid Modernization	ATR Loops	(0.003)	(0.006)	(0.009)	(0.011)	(0.014)
HVD Lines Reliability	HVD Pole Replacements	0.000	0.000	0.001	0.001	0.001
	HVD Pole Top Rehabs	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
	HVD Line Rebuilds	(0.002)	(0.007)	(0.011)	(0.016)	(0.021)
Secondary Improvements		0.001	0.002	0.004	0.005	0.006

FIGURE 6

CAIDI GLIDEPATH BY INVESTMENT/ACTIVITY AREA

	2021	2022	2023	2024	2025
ADMS	(0.5)	(0.9)	(1.4)	(1.9)	(2.3)
Reduced Crew Workload	(1.5)	(3.3)	(5.1)	(6.9)	(8.6)
Forestry	(0.3)	(0.6)	(1.1)	(1.9)	(3.4)
Other Operational Improvements	0.0	(0.2)	(0.8)	(1.7)	(3.0)

In some areas, shown in red as negative numbers, the Company's investments and activities will drive a net reduction in SAIFI over the glidepath period. In other areas, shown in black as positive numbers, SAIFI will actually increase on net due to deterioration; however, the Company's investments in these areas are still necessary to prevent SAIFI from getting even worse. The figures shown for each year are cumulative, not incremental.

As the number of outages is reduced, crews will have to respond to fewer outages; this reduction in workload will allow crews to more quickly address outages that do occur. This will produce CAIDI savings represented by the Reduced Crew Workload line item above.

The three metrics that address individual customer experiences with outages are: customers with five or more outages in one year ("CEMI-5"); customers with one or more outages per year exceeding five hours ("CELID-5"); and customers restored within 24 hours of a MED-related outage.

Current MPSC standards call for the Company to keep CEMI-5 to under 5% of customers each year (Mich. Admin. Code R.460.732 (j)). The Company reports its CEMI-5 performance to the MPSC on an annual basis in Case No. U-12270, with detailed explanations and planned countermeasures if the 5% target is not met.

To determine expected improvement in CELID-5, the Company considered its last five years of results and then applied the projected SAIFI and CAIDI improvements shown in Figure 4 through Figure 6 above. In this analysis, the Company took each of the last five years of data and ran it through a series of simulations. In each simulation, the Company randomly removed 6.4% of the outages to correspond with projected SAIFI improvements through 2025, and then reduced the length of the remaining outages by 8.8% to correspond with projected CAIDI improvements through 2025. This analysis indicates that if projected SAIFI and CAIDI improvements take place, the projected CELID-5 improvements will take place as well.

To determine expected improvement in customers restored following a MED outage, the Company conducted an analysis similar to that done for improvements in CELID-5. The Company compiled its last five years of results, and then ran a series of simulations that randomly removed 6.4% of all outages and then reduced the length of the remaining outages by 8.8%.

c) Cost Metrics

The two cost metrics are intended to ensure that the Company delivers reliability in a cost-effective manner. As will be discussed later in this EDIIP, the two largest and most important (for purposes of their impact to reliability performance) areas of distribution O&M spending are Forestry and Service Restoration. Consequently, in the Company's 2018 EDIIP established Service Restoration O&M cost per incident and Forestry cost per line-mile cleared as its two cost metrics, both of which are maintained in this EDIIP.

As discussed in the section of this report on Service Restoration O&M, the Company projects it will spend $74 million on service restoration each year from 2022 through 2025 and believes that this level of spending represents true service restoration needs. As SAIFI is reduced as described above, the number of incidents to which the Company must respond will decrease as well. This reduction in incidents will effectively lower the denominator used for calculating the O&M cost per incident, raising the O&M cost per incident over the next five years.

As described in the section of this report on Service Restoration O&M, maintaining a consistent level of spending as incidents decrease will allow the Company to engage in more pre-staging of both Company crews and off-system resources in advance of major storms, allowing faster and more efficient response times, reducing outage durations for customers.

Forestry cost per line-mile cleared encompasses the total cost and total mileage for both High Voltage Distribution ("HVD") and Low Voltage Distribution ("LVD") line clearing and is described in greater detail in the section of this report on Forestry O&M. While HVD line-clearing costs are projected to remain flat on a per-mile basis over the next five years, LVD line-clearing costs are projected to increase. Costs per line-mile cleared were unusually low in 2020 (i.e. and outlier year); due to the COVID-19 pandemic, the Company received fewer customer requests for forestry work and with fewer emergent customer requested work, crews had the ability to more quickly and efficiently complete scheduled line clearing. Contributing to increasing costs, the Company is in the first year of a planned multi-year ramp-up of LVD line clearing, and consequently new forestry workers must be trained and gain experience on the Company's system. Additionally, as the ramp-up progresses, crews will be clearing some circuits not cleared in many years, adding to the complexity and expense on a per-mile basis. However, after peaking in the 2024 timeframe, the Company projects forestry cost per line-mile cleared will begin to decrease again, as crews gain experience and as more of the LVD system is cleared on a consistent cycle.

d) Sustainability Metrics

The three sustainability metrics are intended to ensure that the Company reduces its overall waste and carbon footprint as customers reduce their energy usage, targeting both average and peak load as ways to reduce emissions and to reduce needed investment in new capacity to support peak load. The Company's 2018 EDIIP established energy savings due to energy waste reduction ("EWR"); system load factor; and total system losses.

In the 2018 EDIIP, the Company set a target of energy savings due to EWR of 536 GWh in 2022. The Company has been exceeding that amount for the past several years, and projects to continue doing so for the next several years as well. The Company's 2025 target for this metric is tied to the Company's plan in the 2021 IRP, and more detailed information on the underlying calculations is provided in that filing. It is important to note that, even as annual GWh savings sometimes fluctuate from year to year, the summer coincident peak demand savings are projected to continue increasing, from 597 MW in 2020 to 879 MW in 2025.

System load factor is calculated in the report by a) identifying the annual system peak load, b) determining the average hourly system load for the month in which the system peak occurs, and c) dividing that average hourly system load by the annual system peak. Because the Company's entire electric system must be built to address the annual peak, measuring system load factor in this way focuses on how efficiently the system is being used around the time of that annual peak.

System load projections in the 2021 IRP indicate that system load factor will slightly decrease by 2025. This is largely due to the impact of increased EWR on the system: while EWR reduces peak demand, it decreases overall energy usage, and therefore average hourly load, by correspondingly more. In 2020, the system peak load was 8,215 MW. This occurred in July, during which month the average hourly load was 4,748 MW, yielding a system load factor of 58%. In 2025, the annual peak load, as forecast in the 2021 IRP, will be 7,697 MW. That will take place in July 2025, when the average hourly load will be 4,375 MW.

In the 2018 EDIIP, the Company set a target of reducing losses by 65,000 MWh (a 2% reduction) by 2022, based upon historical four-year average line losses of 3,000,000 MWh. The Company has reduced losses by more than 2% through the end of 2019, the most recent date for which loss study information is available. The Company achieved these reduced losses through investments in EWR, Volt-Var Optimization ("VVO") and conductor upgrades on the HVD system as part of HVD Reliability and Capacity projects, among other investments.

Over the next five years, the Company expects to achieve further reductions in losses through additional HVD conductor upgrades, as well as investments in Conservation Voltage Reduction ("CVR"), which builds on VVO (both CVR and VVO are discussed in detail in the sections of this report on Grid Modernization). The projected further reductions in losses in Figure 3 are based on the Company's modeling of the impacts of these projects.

The Company has not modeled the impacts of other LVD investments on reducing system losses. Load on the LVD system is more dynamic than on the HVD system, as new customers can change flows on an LVD circuit more dramatically than on an HVD line. Specific LVD projects are also not generally planned as far in advance as HVD projects. Therefore, it is more difficult to forecast specific system loss reductions due to LVD investments. In general, LVD investments lower losses in the area of a given project where conductors are upgraded, but this does not necessarily translate into system-wide loss reductions.

e) Control Metrics

The two control metrics are designed to measure how well the Company provides customers greater control over their power across a variety of dimensions, including providing information, technology, programs, and services to support customers in managing their electric use.

The first metric measures how many residential customers, in a J.D. Power survey, respond with at least a "9/10" score on a survey question asking, "How would you rate Consumers Energy on helping you manage your monthly energy usage?" This helps ensure that customers believe the Company is supporting greater empowerment, engagement, technology options, and information, in order to meet their supply and consumption needs. The Company regularly conducts research into the underlying drivers of customer expectations in this area.

The Company has, on a standalone basis, seen improvement on this metric since the 2018 EDIIP, and the Company's 2020 score was the highest yet achieved, even as the COVID-19 pandemic introduced new challenges in communicating with customers. Even as the Company makes continuous improvement, so too do other utilities, and as a result while the Company was in the first quartile in 2018 and 2019, it was not in 2020. However, the data indicates that many utilities scored very close together in 2020, putting the Company's 2020 performance within the statistical margin of error relative to other top-performing utilities. Going forward, the Company continues to aspire to top quartile performance, allowing for statistical margins of error.

The 2018 EDIIP established the number of residential customers enrolled in one DR program as a control metric, but the Company's DR program options have significantly expanded since the 2018 EDIIP was filed, and the Company has updated this metric to capture all DR savings. The Company's 2021 IRP establishes a plan for the continued growth of various DR programs for both residential and C&I customers.

iii. Performance-Based Ratemaking ("PBR") Metrics

a) PBR Overview

In its Order in the Company's 2020 electric rate case (Case No. U-20697), the MPSC directed the Company to include a PBR proposal in this 2021 EDIIP. (December 17, 2020 Order in Case No. U-20697, pg. 270-273)

Many parties in Michigan have expressed interest in PBR in recent years, and the Company has been engaged in many discussions on this issue. The Company hosted a series of technical conferences in 2019 in which members of MPSC Staff and other stakeholders exchanged ideas on the topic. As the MPSC stated in the Order, the Company supports exploration of PBR initiatives.

The Company believes that any PBR structures must be designed carefully, to ensure that the incentives are aligned with delivering value to customers. Consider that, in order to develop a PBR framework in Minnesota, utilities, regulators, and other stakeholders spent several years defining objectives and goals, developing metrics to measure those objectives and goals, and then measuring them for several years before attaching any incentives or disincentives for performance. (see "Performance-Based Regulation in Minnesota: A Decade of Progress," https://www.betterenergy.org/blog/performance-based-regulation-in-minnesota-a-decade-of-progress/) In other words, PBR structures should not be imposed in haste, but intentionally and incrementally.

It is important to consider and seek to avoid creating any perverse incentives. For example, SAIDI is a standard reliability metric, and one that the Company proposes to use as a performance incentive mechanism, as detailed below. However, if a PBR framework attached *too much weight* to SAIDI performance, or attached steep financial consequences to SAIDI performance, it would create a perverse incentive for a utility to ignore a relatively small number of customers with poor reliability if those customers' outages did not significantly drive SAIDI on a system-wide level. Similarly, a performance incentive mechanism must balance near-term incentives with the long-term nature of utility investments.

For example, as described later in this report in the section on the HVD Lines and Substations Rehabilitation sub-program, the Company is planning to rebuild certain HVD substations that are well past their expected lifespan. Although these substations do not currently experience significant outages nor significantly drive SAIDI performance, they still represent system deterioration needing to be addressed to prevent larger outages in the future. With a PBR framework that places heavy emphasis on SAIDI with high-stakes financial consequences, there may be less incentive – or even a disincentive – from making a needed long-term investment.

The Company expects that further discussions on PBR will take place following the filing of this 2021 EDIIP. The PBR framework proposal described below represents a reasonable approach to apply PBR to utility distribution system performance. The Company expects to engage with the MPSC and other regulatory stakeholders via this EDIIP filing and in other venues to continue to refine a PBR framework that may be applied to electric distribution system planning in the future. For instance, a MI Power Grid workgroup on Financial Incentives and Disincentives, expected soon, will provide a venue to discuss this and other proposals, and to further explore how PBR might be applied to areas of utility performance beyond reliability.

The Company also expects that specific details involved in the implementation of a PBR framework will be the subject of future regulatory proceedings, such as the Company's subsequent electric rate case filings.

b) PBR Framework

PBR should be considered holistically in Michigan as a tool to 1) reduce capital bias associated with the existing utility regulatory construct; 2) incentivize innovation and development of new business models to support the future clean and decentralized energy system; 3) incentivize performance improvements in support of state policy goals; and 4) provide stability in cost recovery in order to achieve outlined performance goals and metrics. The Company looks forward to further discussion with stakeholders over the next several years to expand upon and refine the framework proposed below. The framework proposed below is the first step toward implementing a holistic PBR framework in Michigan.

As shown in Figure 7 below, this framework should begin with transparency about system performance through regular reporting. The Company regularly provides substantial information about its distribution system performance through various channels, including EDIIP reports; annual power quality and reliability reports (Case Nos. U-12270 and U-16066); meetings with MPSC Staff; electric rate cases and other regulatory filings.

The second part of this framework focuses on the achievement of key distribution performance outcomes, which is the focus of the proposal in this EDIIP. For the purposes of this EDIIP, these key distribution outcomes center around reliability. In the future, Michigan may consider how to tie achievement of these outcomes to cost recovery through multi-year ratemaking or tracking mechanisms, although the Company is not proposing any such proposal in this EDIIP.

The third part of this framework expands beyond the achievement of performance outcomes focused on distribution system reliability and considers incentivizing other policy goals. For example, performance incentive mechanisms might be developed around the development and deployment of NWS, DER interconnections speed, quality, or cost, or development of other innovative utility pilots or products, with incentives tied to the utility achieving certain goals or targets. The Company expects more discussion and collaboration on these additional metrics and incentives to take place in the MI Power Grid process.

FIGURE 7

KEY COMPONENTS OF ELECTRIC UTILITY PBR

	Rationale	Components
Transparency on system performance	Provides insight into current system performance for the utility and stakeholders	EDIIP Report (14 metrics outlined above, grid archetype and prioritization planning details) Annual power quality and reliability reports Annual reliability meetings with MPSC Staff Performance data provided in electric rate cases
Achievement of key distribution system outcomes	Attaches incentives/penalties to achieving system-level distribution system outcomes to focus utility attention on these areas; assigns performance accountability to utility following regulatory approval of reliability investments	SAIDI CEMI-5 Multi-year ratemaking (future potential)
Transition to a cleaner, more distributed future electric system	Aligns utility incentives with state policy objectives	To be determined in the future (may include incentivizing NWS, interconnecting or deploying DERs, optimized distribution and generation planning, etc.). Existing mechanisms include energy waste reduction and demand response earnings mechanisms.

c) Distribution PBR Incentive Proposal

Of the 14 metrics outlined in Figure 3, the Company proposes to use SAIDI and CEMI-5 as performance incentive mechanisms in this filing. The Company also proposes to use CEMI-0 and CEMI-1 as performance incentive mechanisms. These are well-recognized, industry-wide, and benchmarkable metrics, and capture both the overall system reliability (particularly with SAIDI) and individual customer experience (particularly with CEMI). Using both SAIDI and CEMI metrics together can help avoid perverse incentives related to focusing too heavily on a single metric, as discussed above.

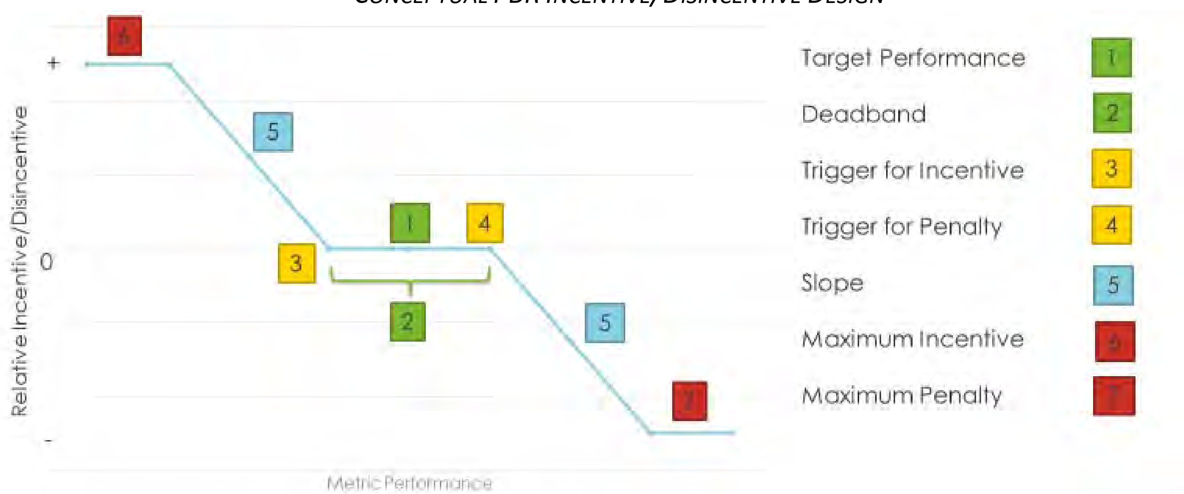
The Company proposes that, for these two metrics, the target and incentive structure discussed below be phased in after 2025, the final year of the five-year spending plan detailed in this EDIIP. The SAIDI glidepath shown in Figure 4 runs through 2025 as well, because the modeling underpinning that glidepath is based on the investments and activities in this five-year spending plan being fully executed, with full recovery of the associated spending. Consequently, the Company proposes that these reliability performance incentive mechanisms take effect at the end of the five-year period of this investment plan.

As noted above, the Company sees reliability performance incentive mechanisms as one component of a comprehensive PBR framework. The Company expects performance incentive mechanisms may expand beyond reliability metrics in the future. This proposal focuses on two reliability metrics.

The Company's proposed design for PBR incentives and disincentives is shown in Figure 8 below. For each metric, there is a target performance level. There is then a performance deadband around that target, and when performance falls within this deadband, no incentive or disincentive is applied. The purpose of this deadband is to minimize impacts of random variation in performance from year to year. Once performance moves outside of the deadband, an incentive or a penalty is triggered. Incentives or penalties are then phased in until performance reaches a maximum impact level, which is intended to place an upper limit on total financial impact of a performance incentive metric in a given year to limit potential volatility to both the Company and to customers. The size of the deadband and the locations of the maximum impact levels are calculated based on the standard deviations of actual performance in recent years.

FIGURE 8

CONCEPTUAL PBR INCENTIVE/DISINCENTIVE DESIGN



For the SAIDI performance incentive mechanism, the Company proposes that the target be set based on the trailing five-year average of actual performance. At the time of this filing, the trailing average of 2016 through 2020 is approximately 200 minutes. However, the Company expects that SAIDI performance will improve through 2025; if the SAIDI glidepath shown in Figure 4 is achieved exactly as shown, then in 2025, the SAIDI target for PBR purposes would be 183 minutes. The actual target will be determined in 2025 based on the trailing five-year average actual performance at that time.

For the CEMI-5 performance incentive mechanism, the Company proposes that the target be set at 5% of all customers. This aligns with the MPSC's existing distribution system performance standard, which the Company reports on an annual basis in Case No. U-12270.

The Company proposes that the deadband for each metric start at one standard deviation below the target (i.e. point 3 in Figure 8) and end at 1.6 standard deviations above the target (i.e. point 4 in Figure 8). The maximum incentive level (point 6) is set at 1.6 standard deviations below the target, and the maximum penalty level (point 7) is set at two standard deviations above the target.

These standard deviations are not symmetrical because the metrics themselves are not symmetrical. in principle, both SAIDI and CEMI-5 can both only go so low. While they could theoretically reach zero, in practice even the highest-performing utilities do not reach that level. In 2020, IEEE surveyed 89 utilities on their 2019 SAIDI performance (https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2020-IEEE-DRWG-Benchmarking-Results.pdf) and the first-quartile cut-off was 86 minutes (more details about these SAIDI quartiles are provided in the Recent System Performance section of this report). Conversely, the highest SAIDI performance noted by IEEE in 2019 was 489 minutes. In other words, median performance, and the Company's typical performance, is already closer to the best-case scenario than the worst case. The proposed deadband and maximum impact levels are intended to offset the asymmetrical risk of the two metrics.

The sizes of the standard deviations should be re-calculated based on actual performance in 2025. However, to illustrate the potential range, the Company has calculated values based on actual performance from 2014 through 2020, as shown in Figure 9 below.

FIGURE 9

ILLUSTRATIVE PBR METRIC STANDARD DEVIATIONS, 2014-2020

	SAIDI	CEMI-5
Standard Deviation, 2014-2020	~23 minutes	1.35% of customers
Illustrative Deadband	23 minutes below target to incentive 36 minutes above target to penalty	1.35% of customers below target to incentive 2.16% of customers above target to penalty
Illustrative Maximum Impact	36 minutes below target to maximum incentive 44 minutes above target to maximum penalty	2.16% of customers below target to maximum incentive 2.70% of customers above target to maximum penalty

The proposed incentives and penalties are summarized in Figure 10 below. For the SAIDI performance incentive mechanism, when performance falls below the deadband (i.e. when performance is one standard deviation below the target), the Company begins receiving a shared savings incentive equal to 6.25% of the reduced customer cost of interruptions based on calculations from the Interruption Cost Estimate ("ICE") tool. These ICE calculations indicate that each minute of SAIDI on the distribution system results in $3.5 million in total economic costs. (Details of this calculation and an explanation of the ICE tool are provided in the testimony of Company witness Brenda Houtz in Case No. U-20963) As SAIDI performance improves, the shared savings percentage earned by the Company would increase on a linear basis until the maximum incentive level of 8% is reached, at which point the shared savings percentage would be capped. The shared savings incentive would be earned in the following year, i.e. if the Company's SAIDI performance in 2026 resulted in a shared savings incentive, then the incentive would be collected in 2027 (further details regarding accounting treatment would be addressed in a future contested case). Using the illustrative standard deviations shown in Figure 9 when the Company's performance first falls below the deadband, shared savings would equal $5 million (6.25% x $3.5M/minute x 23 minutes). When performance reaches the maximum incentive level, shared savings would equal $10 million (8% x $3.5M/minute x 36 minutes). When performance is in the deadband level, or when the performance is above the deadband, no shared savings incentive would be earned.

The proposed MPSC service quality and reliability standards under consideration would require the Company to automatically pay a $35 bill credit to any customer that experiences five or more outages in a year, notwithstanding the Company's systemwide CEMI-5 performance. For this CEMI-5 performance incentive mechanism, the Company proposes that when the Company's systemwide CEMI-5 performance reaches the maximum incentive level, 100% of any bill credits paid during that year may be recovered through rates in the following year. If systemwide performance is between the deadband and the maximum incentive level, 75% of any bill credits paid may be recovered through rates. If systemwide performance is within the deadband, 50% may be recovered; if it is between the deadband and the maximum penalty level, 25% may be recovered; if it reaches the maximum penalty level, then none may be recovered.

FIGURE 10

PROPOSED PBR INCENTIVES AND PENALTIES

	SAIDI	CEMI-5
Type of Impact	Shared savings of ICE reduced cost of interruptions	Recovery of bill credits paid
Maximum Incentive	8% of shared savings of reduced customer cost of interruptions	100% of any credits paid that year may be recovered in rates the following year
Deadband to Maximum Incentive	Linear increase in share savings percentage from 6.25% to 8%	75% of any credits paid that year may be recovered in rates the following year
Deadband	No shared savings	50% of any credits paid that year may be recovered in rates the following year
Deadband to Maximum Penalty	No shared savings	25% of any credits paid that year may be recovered in rates the following year
Maximum Penalty	No shared savings	0% of any credits paid that year may be recovered in rates the following year

In addition to the PBR frameworks for SAIDI and CEMI-5 outlined above, the Company proposes an additional incentive related to CEMI-0 and CEMI-1. SAIFI is generally around 1.0, which implies that the typical customer would anticipate one outage per year, so attaching an incentive to CEMI-0 and CEMI-1 captures all customers who receive this level of reliability or better.

Under this additional incentive, the Company would have a target of 70% of customers at CEMI-0 or CEMI-1 in a year. From 2014 through 2020, the Company averaged 66.3% of customers at CEMI-0 or CEMI-1, with a standard deviation of 4.4% of customers. For this additional incentive, the deadband would be from one standard deviation below to one standard deviation above the target, with a maximum incentive at two standard deviations above the target.

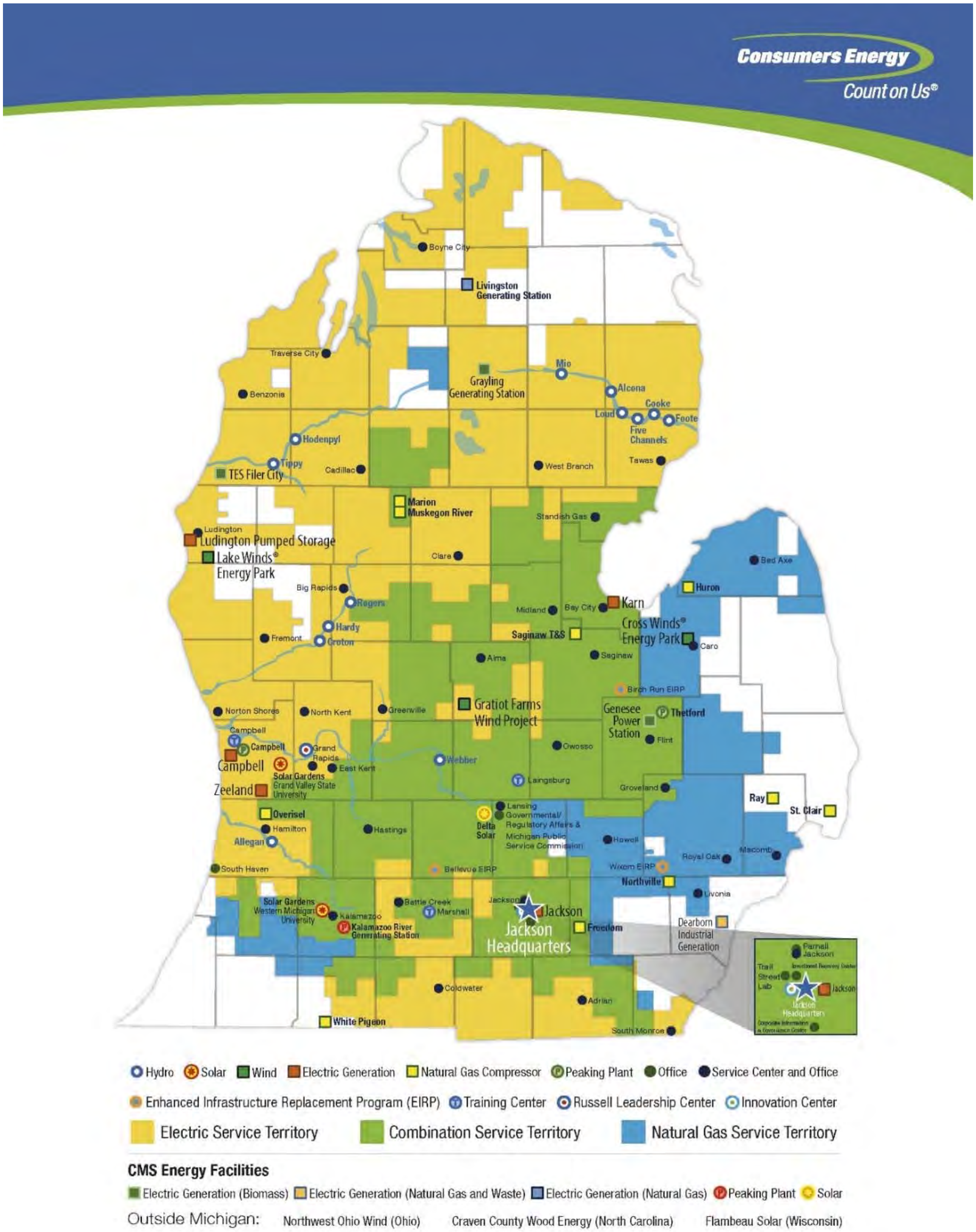
When the Company's systemwide CEMI-0 and CEMI-1 performance reaches the maximum incentive level, the Company would receive an incentive to be collected through rates in the following year, with the specific amount to be proposed in a future electric rate case. If systemwide performance is between the deadband and the maximum incentive level, the Company would collect 50% of the incentive. If systemwide performance is in the deadband or lower, no incentive would be received.

C. Description of System

i. Overview of Service Territory and System Components

The Company's electric distribution system is an essential part of Michigan's infrastructure, serving 1.9 million customers across over 90,000 miles of distribution lines and 1,200 substations in the north, central, and western portions of Michigan from Monroe County to Mackinaw City, as shown in Figure 11 below.

FIGURE 11
CONSUMERS ENERGY SERVICE TERRITORY

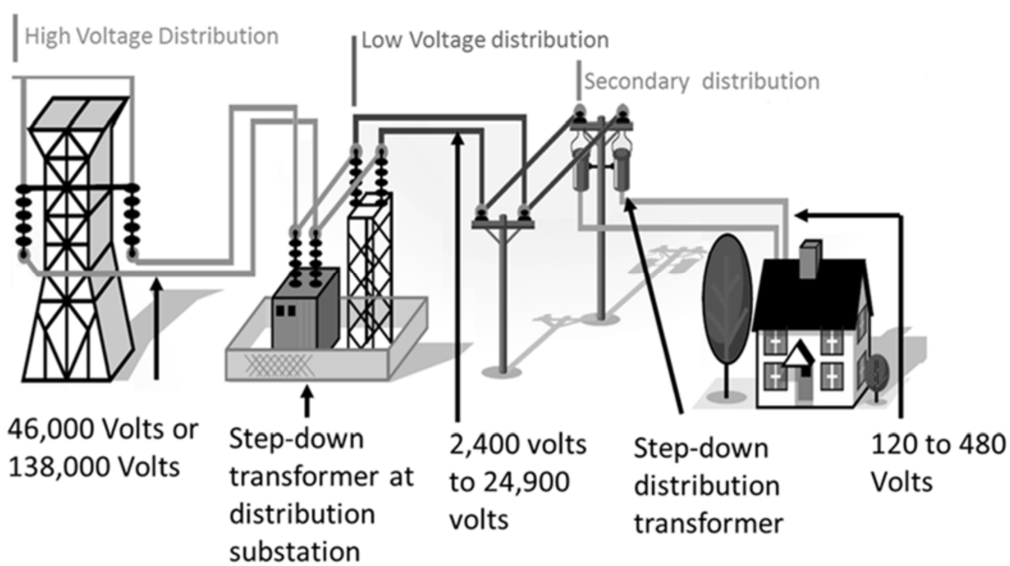


The distribution system is functionally separated by operating voltage into HVD and LVD. The HVD system includes 46 kV lines, radial 138 kV and 69 kV lines, and substations to transform between 138 kV and 46 kV. The HVD system voltage is stepped down, or reduced, at LVD substation transformers onto the

LVD system, which includes primary voltages between 2.4 kV and 24.9 kV (grounded-wye and delta). LVD voltage is then further stepped down at the secondary distribution transformer to a secondary voltage, serving businesses and residences at voltages between 120 volts and 480 volts. The Company's system has over 2,000 LVD circuits serving its 1.9 million electric customers. A circuit is a combination of electrical devices and hardware that are connected together and emanate from an LVD substation to deliver electrical energy to customers, operating at a defined nominal voltage. The primary distribution system begins at the distribution substation and ends at the distribution transformer. The secondary distribution system begins at the distribution transformer and ends at the customer, as shown in Figure 12 below.

FIGURE 12

ILLUSTRATION OF ELECTRIC DISTRIBUTION SYSTEM



The LVD system is comprised of over 87,000 total miles of lines, made up of approximately 51,000 miles of primary overhead, 9,000 miles of primary underground, and 27,000 miles of secondary. The LVD system consists of 13 different voltages because the Company acquired several distribution systems from smaller distribution companies over its history.

The LVD system also includes a distinct component called the Metro system, which provides underground distribution service in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw. The Company's Metro planning group focuses solely on these key downtown areas, reflecting the Company's commitment to investment in Michigan by dedicating specific attention to these areas of economic growth.

The HVD system comprises all assets from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations. It is comprised of and represented by three distinct networks: (i) HVD substations; (ii) HVD lines; and (iii) LVD substations. LVD substations are included as part of the HVD system in order to leverage substation planning, engineering expertise, and large equipment resourcing in a consistent and efficient manner.

The Company's HVD substation network consists of approximately 180 substation locations that contain HVD assets. This is comprised of approximately 120 substations with 138 kV to 46 kV transformation and approximately 60 substation locations that contain Company-owned 46 kV breakers but have LVD or customer transformers or are switching stations.

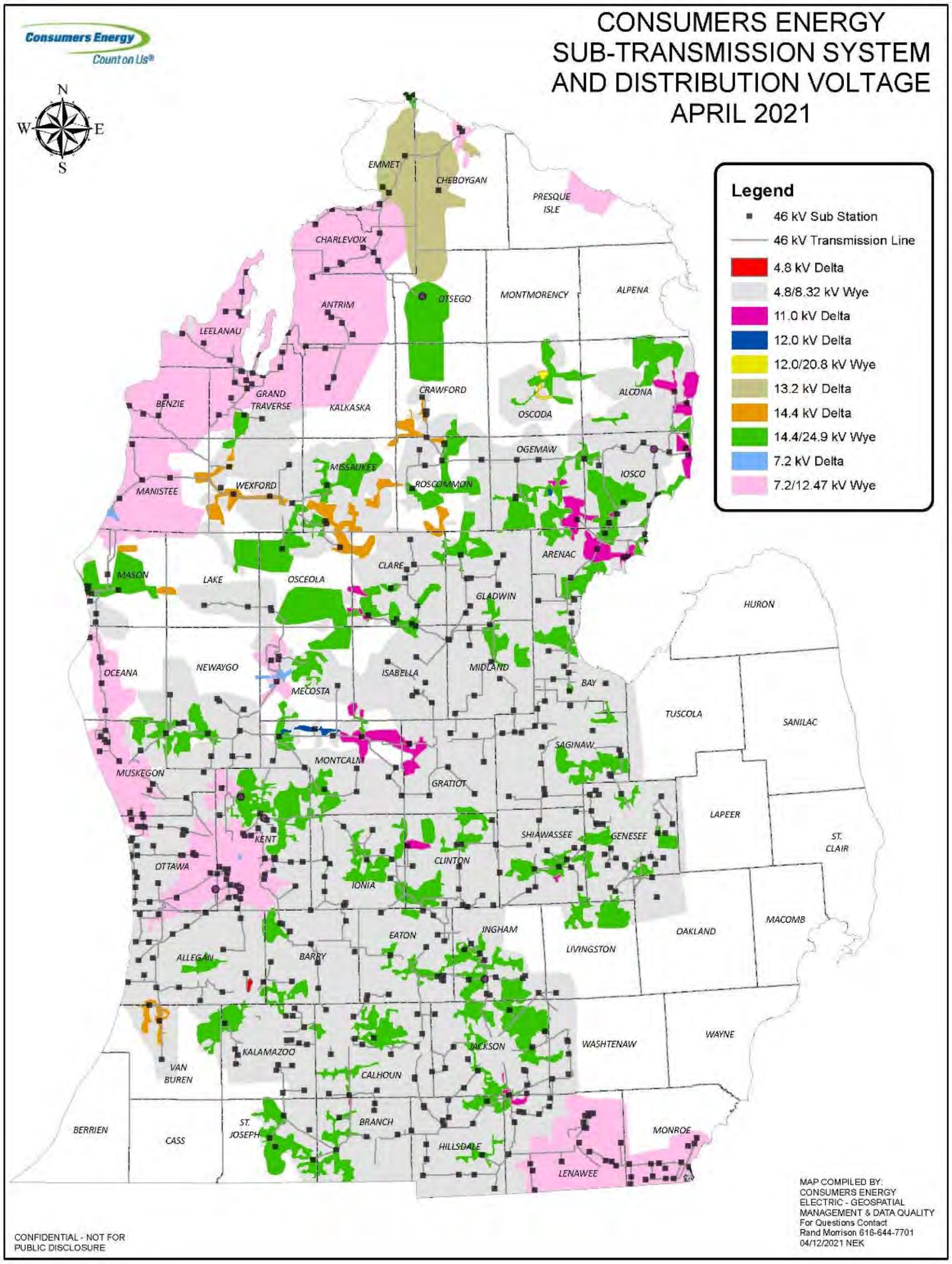
The Company's HVD lines network consists nearly entirely of 46 kV lines (96% of the total), but also includes radial 138 kV and 69 kV lines (4% and <1%, respectively). The HVD system is comprised of approximately 4,600 total miles, with approximately 4,400 of those miles being 46 kV and 69 kV overhead lines and 19 miles being 46 kV underground lines; and approximately 200 miles being 138 kV overhead lines and four miles being 138 kV underground lines.

The LVD substation network consists of almost 1,100 substations. This is comprised of 783 general distribution substations, 230 Consumers Energy-owned dedicated customer substations, 35 customer-owned dedicated substations, 5 Consumers Energy-owned substations providing wholesale distribution service to rural co-op and municipal systems, and 30 customer-owned substations providing wholesale distribution service to rural co-op and municipal systems.

A more detailed map of the Company's distribution system, including voltage levels, is shown in Figure 13 below.

FIGURE 13

SERVICE TERRITORY VOLTAGE MAP



ii. System Condition

Throughout more than a century of distributing electricity, the Company's service area has expanded to serve many new communities and businesses in Michigan. Much of this timeworn infrastructure – lines, poles, pole top equipment, and substations, among other assets, needs replacement. It is important to emphasize that age is not the only indictor of system health and is not the only driver of when an asset must be replaced. The Company thinks holistically about how to best serve customers reliably, and this means assets are replaced based on their overall deterioration. In short, the Company develops projects to proactively replace, rebuild, or rehabilitate assets when inspections or performance data indicate that the asset is in a state of deterioration. Of course, the Company also replaces assets that fail in the field.

The deterioration and health of assets vary based on field conditions (e.g., soil, weather, grade/slope, wind patterns, etc.), location, and materials used by the manufacturer (e.g., wood type, porcelain, polymer, interrupting media, etc.). For example, poles deteriorate at a faster rate in wet soil conditions than in dry non-acidic soil conditions, and porcelain is more susceptible to freeze/thaw conditions than polymer.

When the Company was developing the 2018 EDIIP, it did not have a comprehensive and accurate gauge of overall system condition, particularly for LVD assets, which made it difficult to accurately account for system deterioration. This was partially due to the historic treatment of LVD assets on a mass property accounting basis, which makes it more difficult to assess LVD system age. The Company is enhancing its distribution asset management capabilities, as discussed later in this report, to address this issue. Even as the Company's distribution asset management capabilities remain under development, the Company has developed new analytical approaches to assess system deterioration, particularly using system performance data during adverse weather conditions, as discussed further below.

a) Lifecycle Analysis

Deterioration has accumulated in the distribution system over the years, largely due to the size of the system relative to ongoing annual available investment to replace assets. Figure 14 illustrates levels of capital investment to replace distribution assets. It reflects the Company's investment levels in 2020 (the most recent completed year) and in 2022. It also reflects the level of investment that would be needed to break even against system deterioration, as defined by replacing assets when they reach the end of their lifecycle. Figure 14 also shows corresponding needs for Forestry O&M spending, which complements capital investment in the distribution system. Overall, this illustrates that even as the Company increases investments to replace distribution assets, there is still a range of time before some assets are being replaced on-cycle, particularly for the LVD system.

It is important to note that, while Figure 14 may appear to suggest that the Company is "overinvesting" in HVD Lines and LVD Substations, this is not the case. Specific investment plans for those assets are discussed later in this report, but in the case of LVD Substations, many investments are driven by factors other than deterioration-related asset replacement, such as animal mitigation, capacity increases to address local load growth, and replacement of defective transformers. In the case of HVD Lines, the Company is in the midst of a large effort to rebuild HVD lines to deliver immediate reliability benefits, overcoming deterioration that has accumulated on the HVD system.

FIGURE 14

CAPITAL INVESTMENT RELATIVE TO BREAKEVEN AGAINST DETERIORATION

Category	Units	SAIDI 2020 Actual Minutes	2020		2022		Breakeven Deterioration	
			Annual Spend	Equiv Units/Yr	Annual Spend	Equiv Units/Yr	Annual Spend	Equiv Units/Yr
LVD Forestry (O&M)	60,000 Miles	74	$55M	5,223 Miles	$94M	7,117 Miles	$120M	9,052 Miles
LVD Primary Circuits	57-Yr Life 60,000 Miles	94	$66M	263 Miles	$123M	489 Miles	$264M	1,053 Miles
HVD Lines	70-Yr Life 4,600 Miles	11	$32M	69 Miles	$89M	195 Miles	$30M	66 Miles
LVD Substations	50-Yr Life 1,100 Subs	10	$32M	25 Subs	$43M	33 Subs	$29M	22 Subs
HVD Substations	70-Yr Life 120 Subs	3	$11M	1 Subs	$36M	3 Subs	$34M	3 Subs
Total		**192***	**$141M (Capital)**		**$291M (Capital)**		**$384M (Capital)**	

*Not including 2 SAIDI minutes associated with the transmission system

The purpose of Figure 14 is to reflect investments that replace assets on a lifecycle basis, so investments in the New Business, Asset Relocations, and Demand Failures capital investment programs are not included in the numbers. New Business investments generally do not replace assets at all, but instead construct new assets to connect new customers or expand service to existing customers. Demand Failures and Asset Relocations investments can involve the replacement of assets, but not necessarily on a lifecycle basis. In other words, since those investments are purely reactive and may involve assets that were still new and/or well-performing, their purpose is not to address system deterioration in a preventative manner. Regarding Demand Failures investments, the Company is working to reduce these through more targeted projects planned in advance.

While the data in Figure 14 illustrates the gap between the Company's investments and investment levels that would represent full replacement of assets on a lifecycle basis, this data does not demonstrate in a standalone manner that deterioration is actually taking place on the system. When considering entire asset classes, assuming that most assets in a given class will deteriorate at a rate commensurate with expected useful life, age is a reasonable proxy for calculated an overall level of investment that would result in keeping up with deterioration. But, as noted above, the Company does not replace individual assets solely due to age, and not all assets deteriorate at a uniform rate.

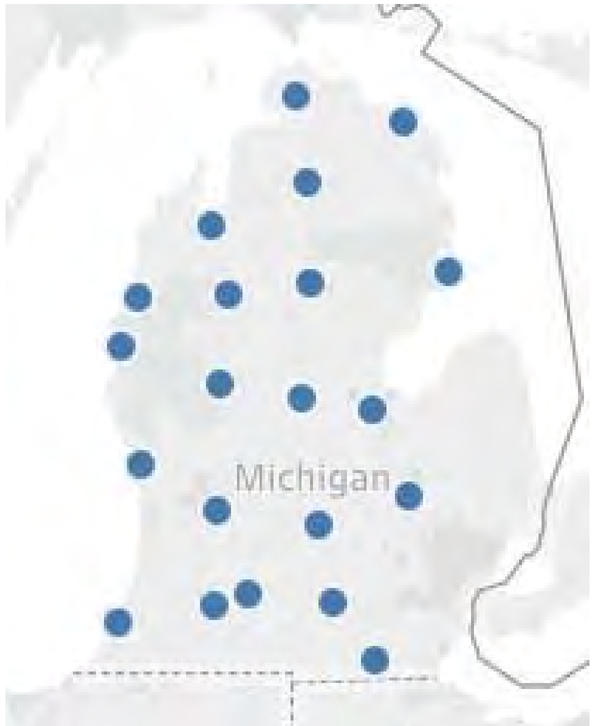
While this lifecycle analysis illustrates why deterioration would occur, the clearest indicator of system deterioration comes from system performance data gathered during storm conditions.

b) Deteriorating Performance during Storm Conditions

The Company monitors wind speed data from 21 different official National Weather Service stations in Michigan, as shown in Figure 15 below.

FIGURE 15

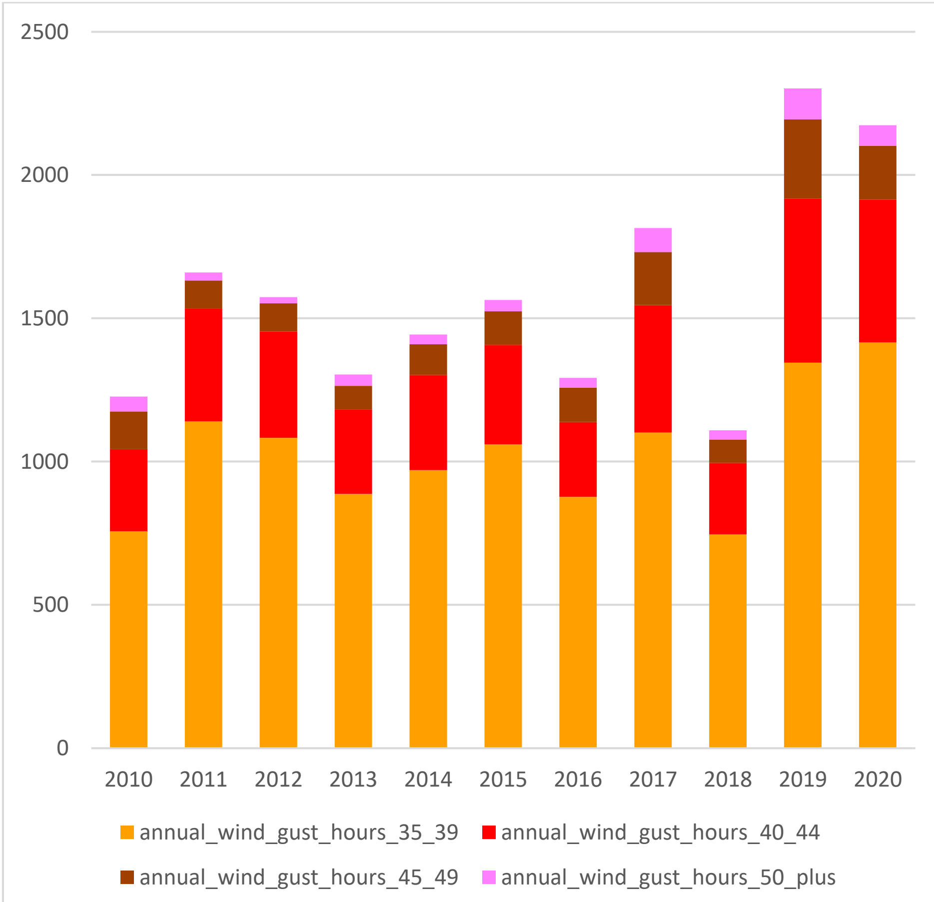
OFFICIAL NATIONAL WEATHER SERVICE WIND OBSERVATION STATIONS



In recent years, the Company has observed that wind speeds across the system have increased in severity. Wind gusts are particularly damaging to the system, given the often-violent nature of gusts. The National Weather Service observation stations record gusts when there are rapid fluctuations of 10 miles per hour or more between peaks and lulls over a 10-minute window, with a gust speed being the maximum wind speed observed in that window. Figure 16 below illustrates the number of hours, aggregated across the 21 observation stations, during which gusts of more than 35 miles per hour were observed. As illustrated, 2019 was also the gustiest year in the past decade and 2020 was the second gustiest, while 2017 was also severe.

FIGURE 16

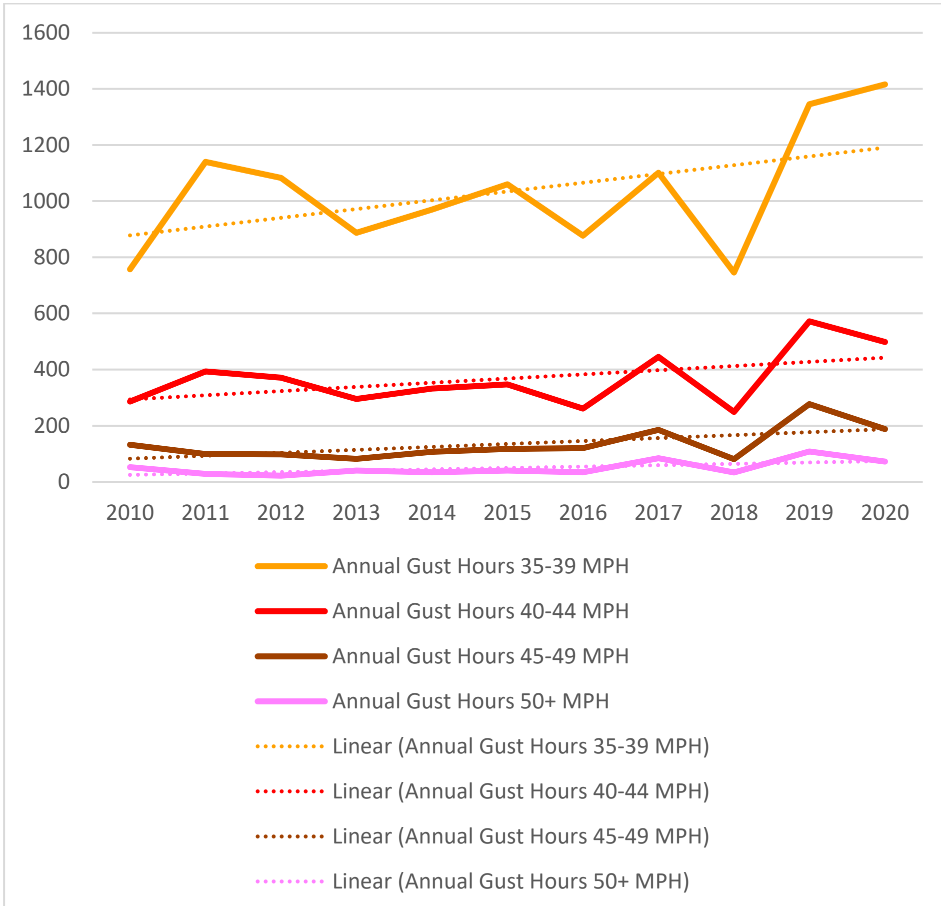
STATION HOURS EXCEEDING HIGH GUST THRESHOLDS



To further illustrate the increasing severity of gusts, Figure 17 below isolates the frequency of gusts exceeding 40 miles per hour. As illustrated by the trend lines, gusts have been becoming more frequent at each of the high-speed bands.

FIGURE 17

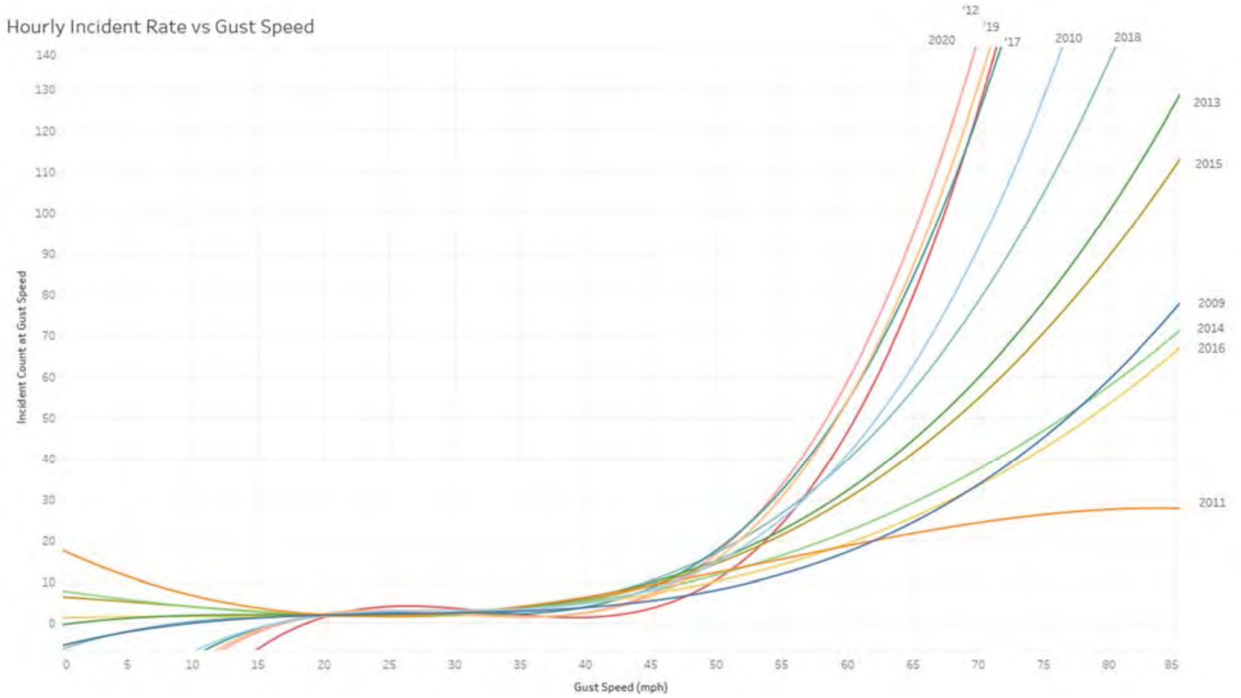
STATION HOURS EXCEEDING HIGH GUST THRESHOLDS



The data in Figure 16 and Figure 17 illustrates only wind gust speed has been getting stronger. To illustrate system deterioration, the Company has plotted gust speeds against the number of incidents on the system, shown in Figure 18 below.

FIGURE 18

INCIDENT RATE VS GUST SPEED



As shown in this data, once gust speeds begin to exceed approximately 45 miles per hour, incidents tend to increase. This data also shows that, at any given higher gust speed, the number of incidents has been increasing in recent years, with 2017, 2018, 2019, and 2020 all among the worst-performing years since 2009. This trend is indicative of system deterioration--at any given level of adverse weather, the system is less resilient than it was in the past.

"Incident," in this case, is defined as any event in which electric service is interrupted to one or more customers. For each incident on the system, the Company obtained the gust data for the hour of the incident from the nearest National Weather Service observation station. To most accurately reflect system deterioration in this data set, all major event days are included, and incidents are counted equally irrespective of the number of customers interrupted.

D. Recent System Performance

The Company assesses its performance on three levels, each of which is important for identifying needed infrastructure investments on the distribution system and for comprehensively measuring reliability:

- **Systemwide performance and external benchmarking** – Comparing system-wide performance to historic levels to understand opportunities to improve the electric distribution system as a whole, as well as how the Company performs relative to peers;
- **Regional performance and internal benchmarking** – Analyzing system metrics at a more granular level across the Company's service regions, to "de-average" the system and understand the service experience, outage causes, and more detailed opportunities for improvement across the state; and

- **Circuit-level performance** – Determining which circuits on the system face the most severe performance challenges, to pinpoint the highest priority locations for system investment.

The Company's reliability performance is monitored and managed through an Electric Reliability Rally Room, a collaboration area that promotes improved visibility and accountability of performance, though this process has largely been done remotely during the COVID-19 pandemic. This Rally Room process reviews data illustrating top reliability drivers to help isolate the root causes of the most significant reliability issues, including where outages are occurring and the causes of outages. This process follows a four-step "Plan, Do, Check, Act" cycle that identifies detailed action plans with timelines, required resources, and responsible parties. Reliability performance can then be measured against these plans to evaluate results, with plans adjusted as countermeasures are identified for emergent issues.

i. Systemwide Performance and External Benchmarking

System-wide performance metrics form the core of reliability performance measurement. Ongoing efforts to improve system reliability for customers are based on a holistic approach to reduce the duration and frequency of interruptions to customers. There are several standard industry metrics commonly used to measure this performance, which were each included in Figure 3 earlier in this report: SAIDI, SAIFI, CEMI, CELID, and restoration time following a MED interruption.

Figure 19 and Figure 20 illustrate the Company's systemwide performance in SAIDI and SAIFI relative to quartiles of peer utilities compiled by IEEE (note that 2020 IEEE quartile data will not be published until later in 2021). These figures illustrate that, while SAIDI performance has often been in the fourth quartile, SAIFI performance is consistently second quartile, and as the SAIDI glidepath in Figure 4 is realized, the Company's SAIDI performance relative to peers will improve significantly.

FIGURE 19

SAIDI (EXCLUDING MEDS) COMPARISON OF CONSUMERS ENERGY TO IEEE QUARTILES, 2007-2020

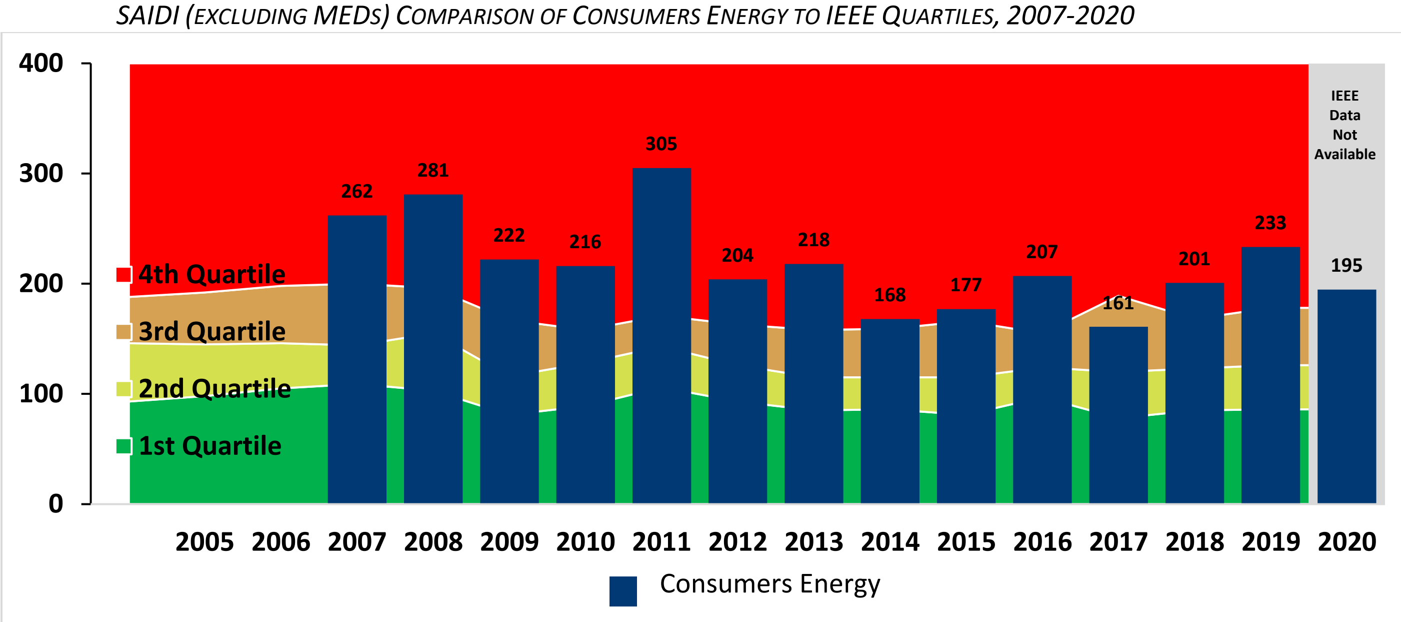


FIGURE 20

SAIFI (EXCLUDING MEDS) COMPARISON OF CONSUMERS ENERGY TO IEEE QUARTILES, 2007-2020

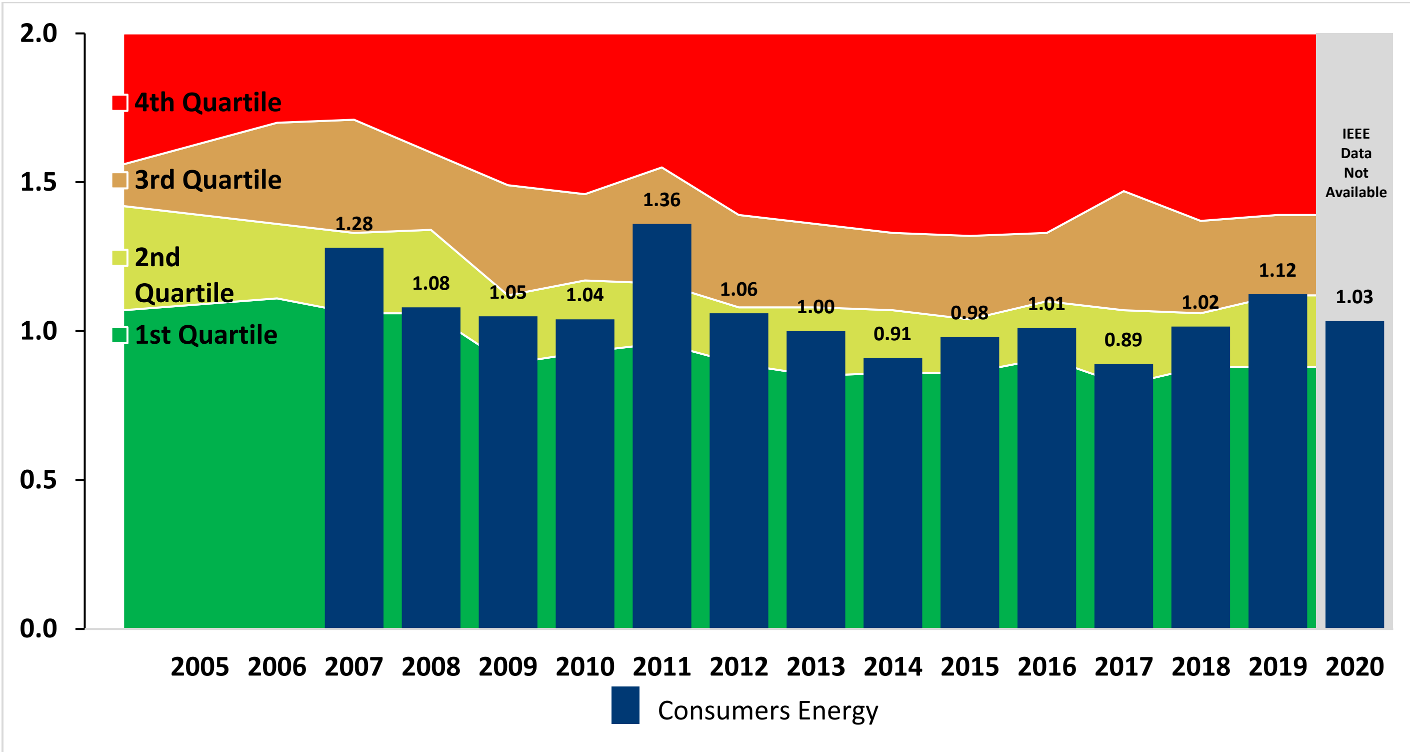


Figure 21 outlines the rolling five-year averages for SAIDI and SAIFI.

FIGURE 21

SAIDI and SAIFI Indices (Five-Year Rolling Average)						
Year	All Conditions		Excluding Major Event Days			
	SAIDI		SAIDI		SAIFI	
	Annual	5 Yr. Avg.	Annual	5 Yr. Avg.	Annual	5 Yr. Avg.
2016	284	543	207	195	1.01	0.99
2017	606	563	161	186	0.89	0.96
2018	407	423	200	183	1.02	0.96
2019	691	486	235	196	1.13	1.01
2020	510	500	195	200	1.03	1.02

The last five years of CEMI performance data is shown in Figure 22 below. While CEMI-5 is the Company's official metric, this table shows performance for multiple numbers of outages. This data is representative of all interruptions on the system, excluding momentary outages as defined by IEEE; it does not exclude MEDs.

FIGURE 22

CEMI by Year											
	% of Customers experiencing X or more interruptions										
Year	0	1 +	2+	3+	4+	5+	6+	7+	8+	9+	10+
2016	40.0%	60.0%%	29.8%	14.3%	6.8%	3.0%	1.3%	0.6%	0.3%	0.1%	0.0%
2017	37.1%	62.9%	33.8%	16.7%	8.5%	4.4%	2.4%	1.3%	0.8%	0.4%	0.2%
2018	36.8%	63.1%	34.0%	16.3%	8.1%	4.2%	2.3%	1.1%	0.6%	0.3%	0.2%
2019	30.0%	70.0%	40.8%	22.4$	12.6%	7.1%	4.0%	2.3%	1.2%	0.6%	0.3%
2020	36.2%	63.8%	35.1%	18.4%	9.4%	4.7%	2.4%	1.2%	0.6%	0.3%	0.1%

The Company's CELID-5 performance over the last five years is shown in Figure 23 below. As with CEMI, this data is representative of all interruptions on the system, including MEDs.

FIGURE 23

CELID-5 by Year	
2016	20.8%
2017	31.1%
2018	36.4%
2019	33.0%
2020	27.1%

The Company's performance in restoring customers within 24 hours of a MED interruption is shown in Figure 24 below. This is calculated by taking the total number of MED incidents each year and determining what percentage of those incidents were resolved within 24 hours.

FIGURE 24

Customers Restored within 24 Hours of a MED Interruption	
2016	93.1%
2017	70.6%
2018	83.0%
2019	76.5%
2020	74.6%

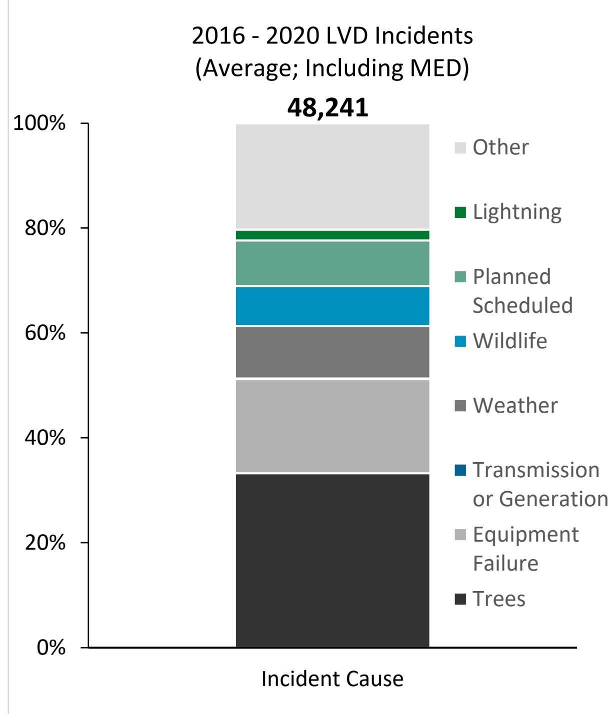
In addition to monitoring and analyzing systemwide reliability trends, the Company also assesses the causes of outages, in order to better understand major drivers of system performance and determine how specific causes are trending over time. This is important for identifying the highest priority investment areas for improving reliability.

Figure 25 and Figure 26 show the average number of outage incidents, individual customer interruptions, and individual customer interruption minutes from 2016 through 2020 for the LVD and HVD systems, including all conditions (i.e. not excluding MEDs).

FIGURE 25
LVD OUTAGE INCIDENT SUMMARY

Average of 2016-2020

Cause	Incidents	Customer Interruptions	Interruption Minutes
Equipment Failure	8,667	287K	65M
Lightning	1,005	36K	10M
Other	9,787	511K	116M
Planned Scheduled	4,196	86K	9M
Transmission or Generation	59	7K	1M
Trees	16,034	772K	421M
Weather	4,838	260K	186M
Wildlife	3,655	45K	6M
Total	**48,241**	**2,003K**	**814M**



2020 Totals

Cause	Incidents	Customer Interruptions	Interruption Minutes
Equipment Failure	10,224	323K	76M
Lightning	891	27K	6M
Other	11,003	636K	146M
Planned Scheduled	5,987	123K	17M
Transmission or Generation	70	19K	3M
Trees	15,904	705K	397M
Weather	4,857	267K	202M
Wildlife	4,319	63K	8M
Total	**53,255**	**2,162K**	**855M**

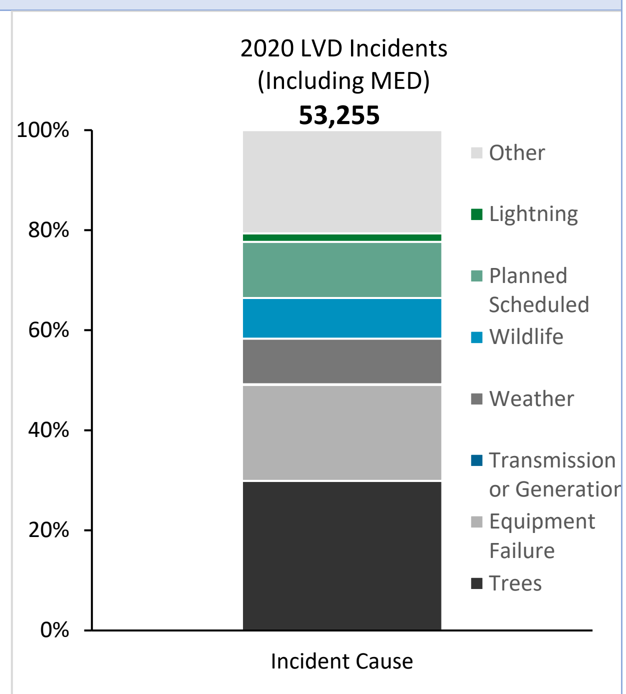
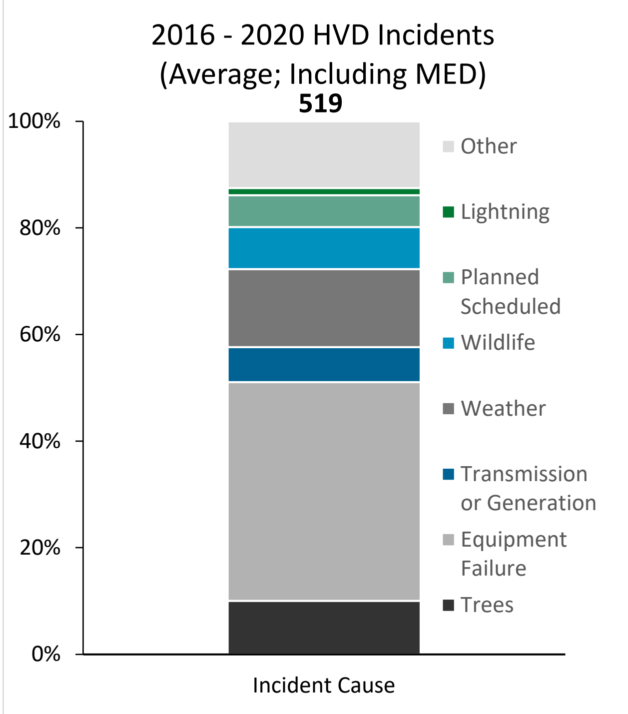


FIGURE 26

HVD OUTAGE INCIDENT SUMMARY

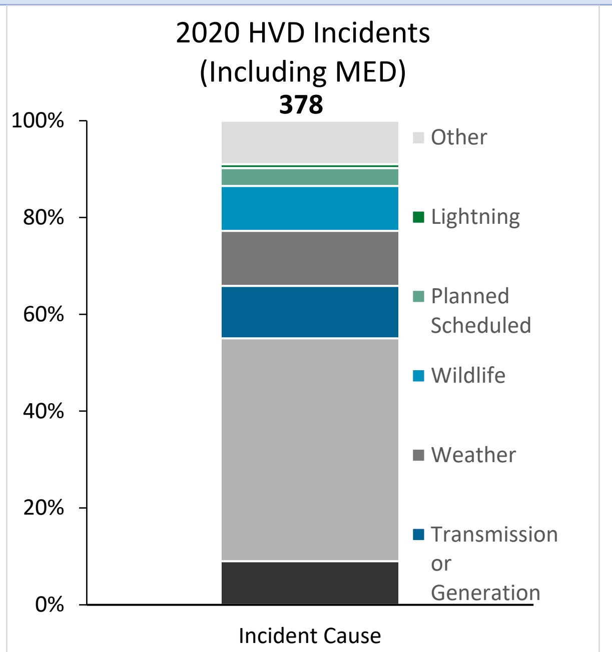
Average of 2016-2020

Cause	Incidents	Customer Interruptions	Interruption Minutes
Equipment Failure	213	161K	33M
Lightning	7	6K	2M
Other	65	50K	7M
Planned Scheduled	31	28K	4M
Transmission or Generation	34	24K	3M
Trees	52	42K	14M
Weather	76	53K	19M
Wildlife	41	33K	7M
Total	**519**	**397K**	**90M**



2020 Totals

Cause	Incidents	Customer Interruptions	Interruption Minutes
Equipment Failure	174	146K	30M
Lightning	3	3K	1M
Other	34	17K	2M
Planned Scheduled	14	10K	1M
Transmission or Generation	41	29K	4M
Trees	34	32K	23M
Weather	43	20K	15M
Wildlife	35	28K	6M
Total	**378**	**286K**	**81M**



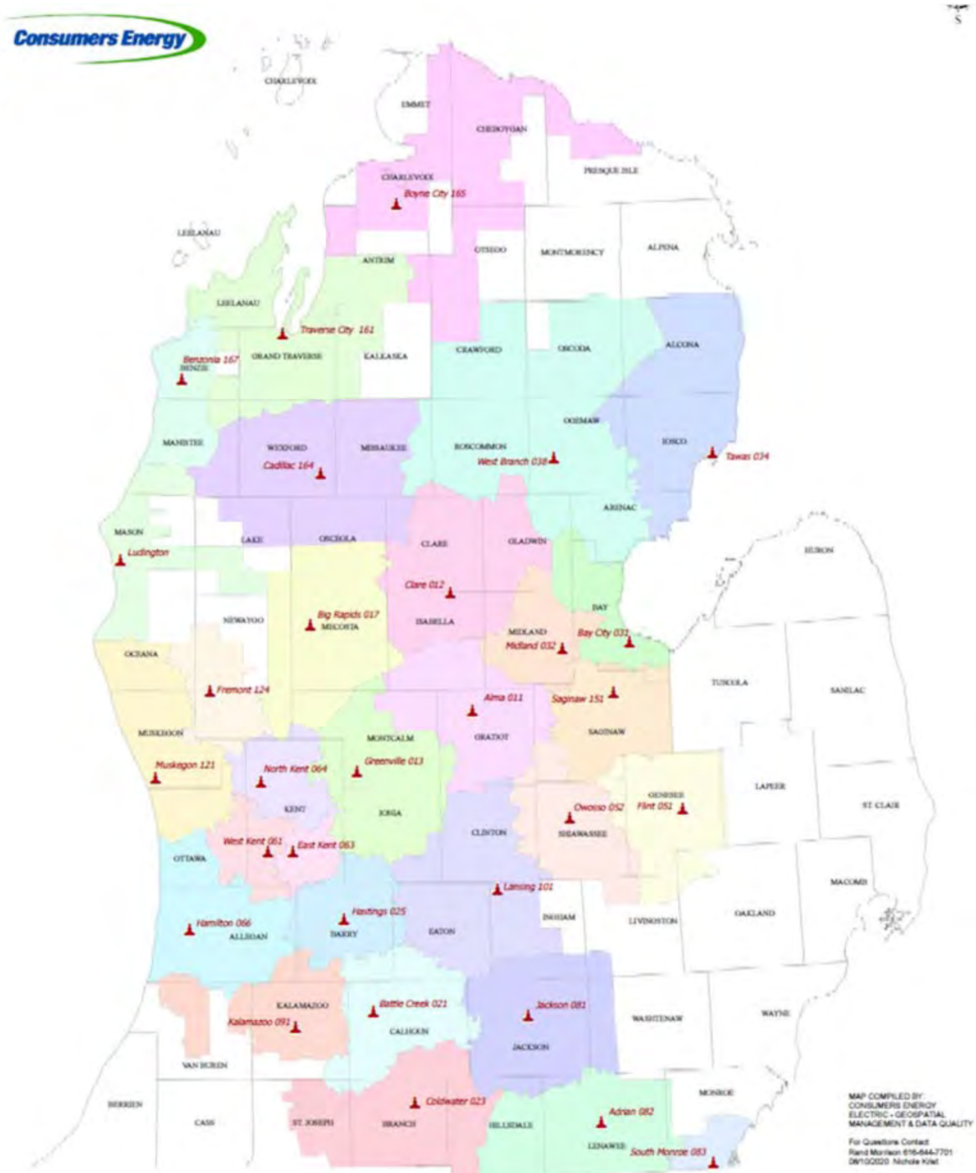
In these figures, "Other" includes unique incidents, public tree trimming, car-pole accidents, public damage, trees outside the right-of-way ("ROW"), and forced outages.

ii. Regional Performance by Service Region

In addition to monitoring performance at a systemwide level, the Company also uses data from its Outage Management System ("OMS") to conduct a more detailed analysis at the service region level. The system is divided into 30 service regions, each with its own dedicated service center, as show in Figure 27 below.

FIGURE 27

SERVICE REGIONS AND SERVICE CENTERS



To define service region boundaries, the Company has considered the location of each service center relative to locations of potential interruptions that could be serviced from that location. These boundaries are used as the basis for assigning work to operational resources and are reviewed annually to ensure the most optimal design for responding to customer needs.

The same measures that the Company monitors on a systemwide level can be analyzed at a service region level to reveal local variations in performance across the system. This allows the Company to "de-average" the system, leading to more targeted infrastructure investments.

FIGURE 28, ***FIGURE 29***, and ***FIGURE 30*** show the average SAIDI, SAIFI, and CAIDI by service region, excluding MEDs, from 2016 through 2020. A full list of the service center abbreviations can be found in Appendix B. Evident in the data, the worst performing service region by SAIDI and SAIFI has been Tawas ("TWS"). This is largely due to the nature of that service region, which serves a rural component of the system with a lower customer density per line mile than many other service regions, meaning it has many circuits that cover long distances. This region of Michigan can also require longer travel times for crews to respond to outages that occur. When the 2018 EDIIP was filed, the worst performing service region was West Branch ("WBR"), for similar reasons. Since the 2018 EDIIP was filed, the Company has opened the Tawas Service Center and separated the Tawas service region from the West Branch service region. Opening this new service center is intended to allow for quicker responses to outages in this more remote part of the state, improving reliability in the area.

FIGURE 28

SERVICE REGION AVERAGE SAIDI (EXCLUDING MEDS), 2016-2020

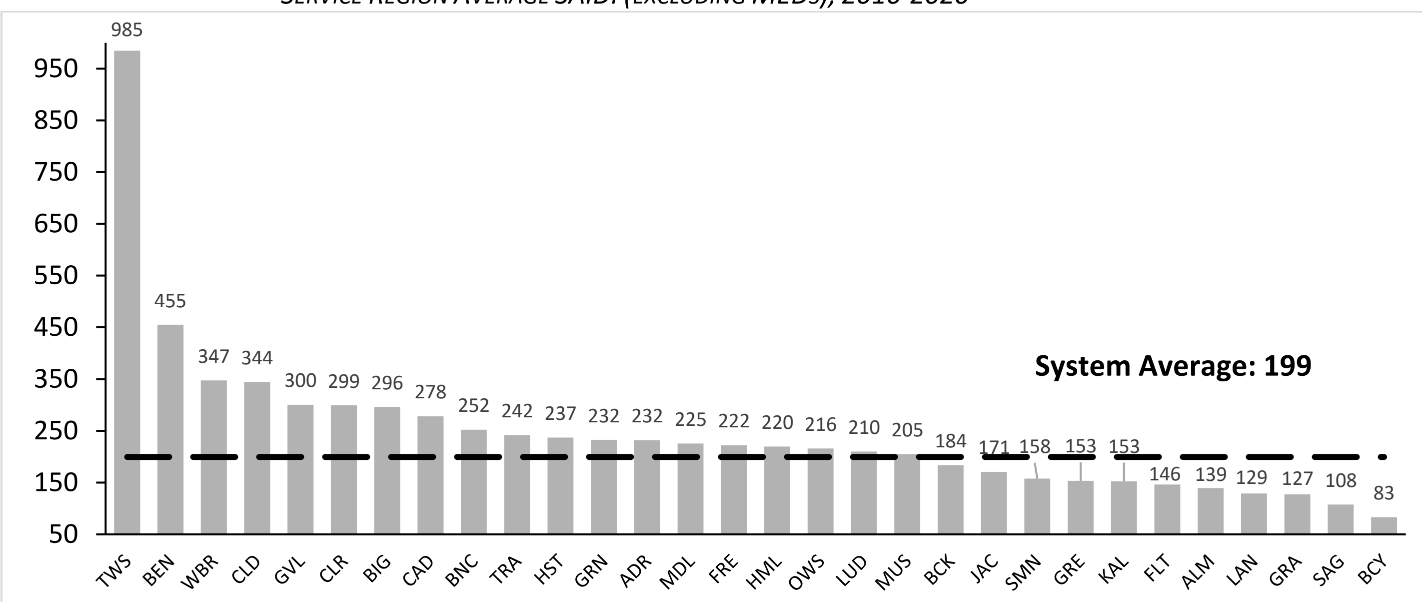


FIGURE 29

SERVICE REGION AVERAGE SAIFI (EXCLUDING MEDS), 2016-2020

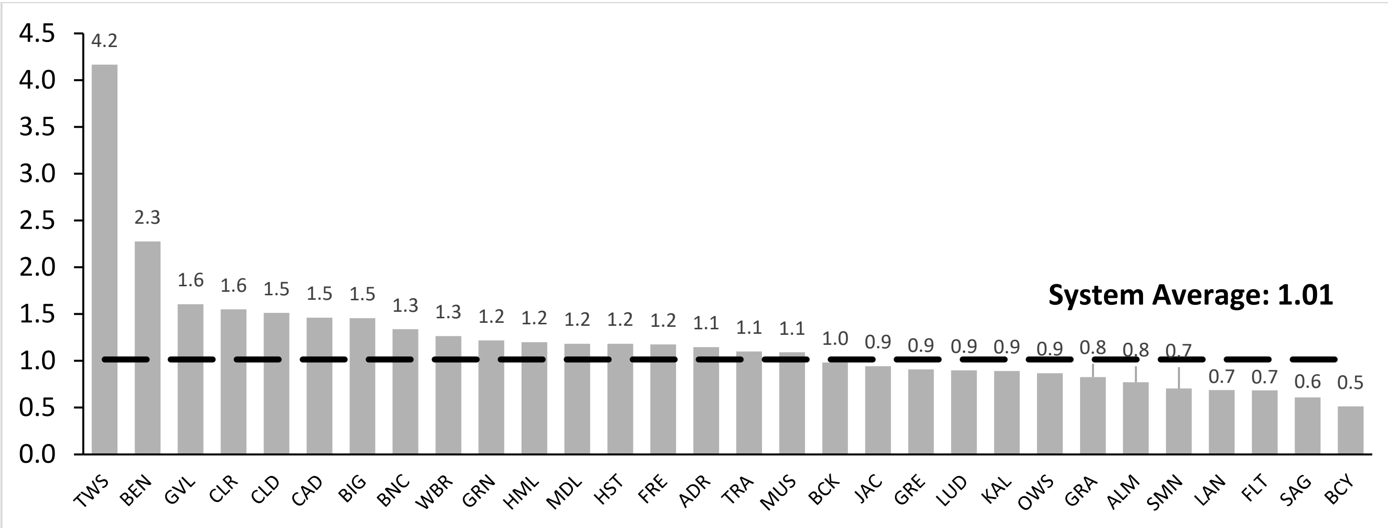
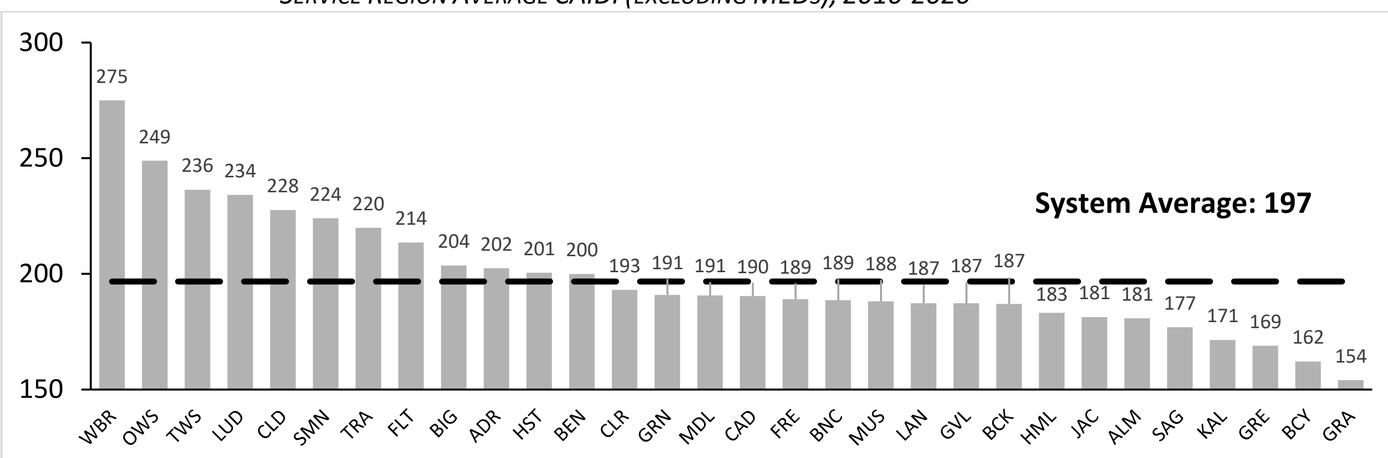


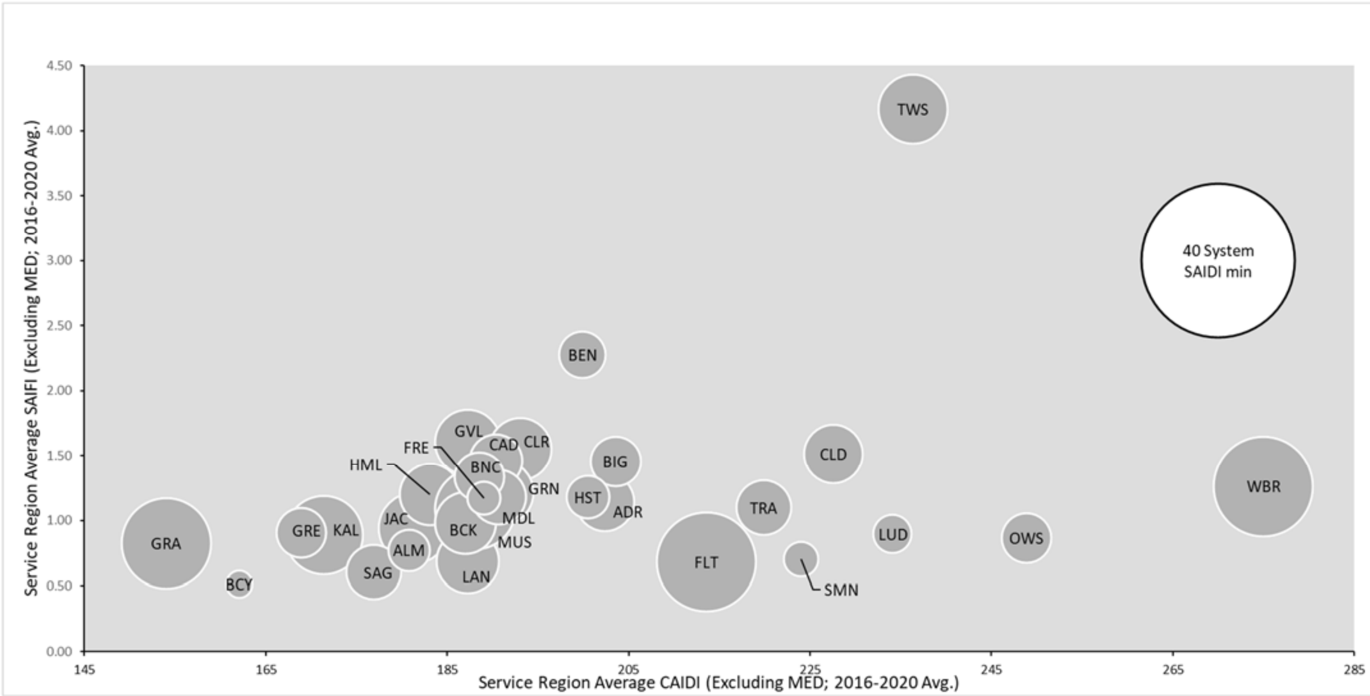
FIGURE 30

SERVICE REGION AVERAGE CAIDI (EXCLUDING MEDS), 2016-2020



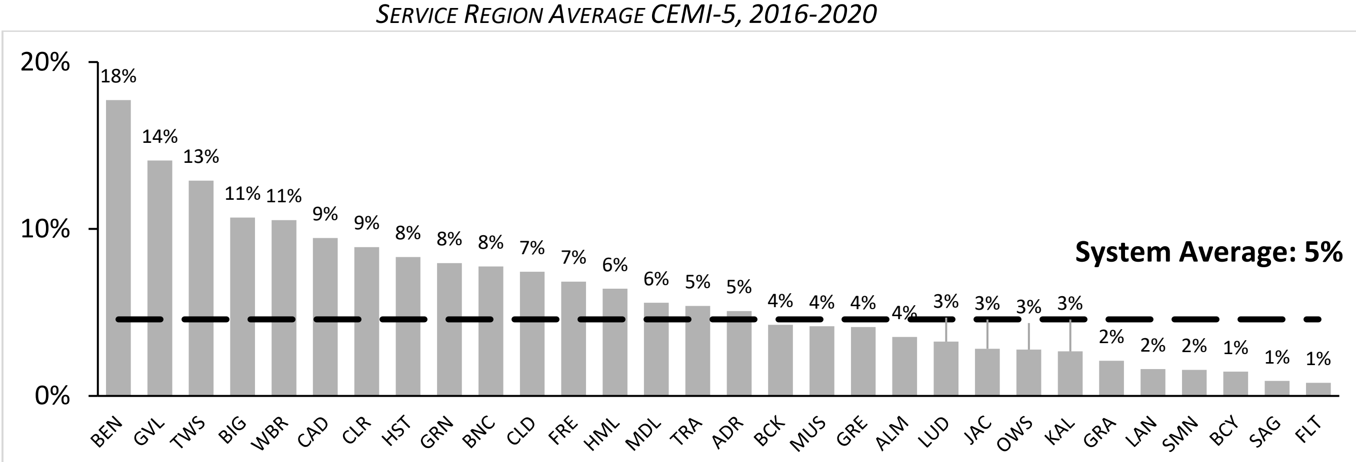
Reliability performance of a service region does not always correlate with its contribution to overall system metrics, given the different populations served by each service region. Figure 31 breaks down service region SAIFI and CAIDI while also mapping the overall contribution of each service region to system SAIDI. The larger the size of a circle, the more minutes that service region contributes to overall system SAIDI. For example, the circle for Flint ("FLT") is just under half the size of the 40-minute reference bubble, and the Flint service contributed an average of 17 minutes to total system SAIDI during the five-year period from 2016 through 2020. Note that the Grand Rapids service region ("GRA"), served from the West Kent service center, had the lowest CAIDI and one of the lowest SAIFI performances of all service centers, yet still contributed 14 minutes to systemwide SAIDI, the third-most on the system. This is because the Grand Rapids service region contains a significant proportion of the system's total population, with over 10% of total customers.

FIGURE 31
SERVICE REGION SAIFI VS. CAIDI



The Company also monitors service region performance for the other three primary reliability metrics. Figure 32 shows the service region performance on CEMI-5.

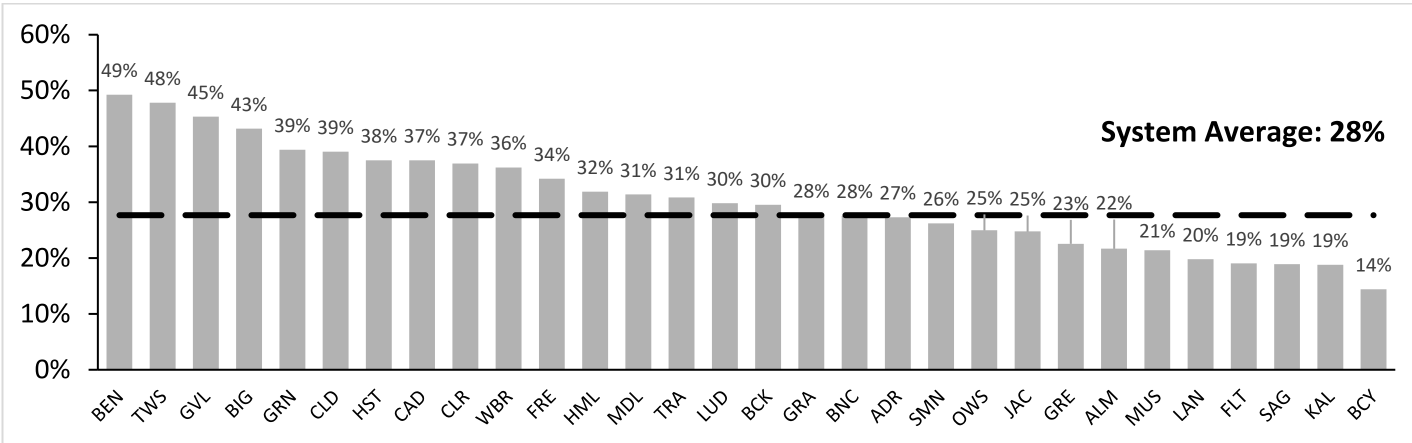
FIGURE 32
SERVICE REGION AVERAGE CEMI-5, 2016-2020



Service region performance on CELID-5 is shown in Figure 33.

FIGURE 33

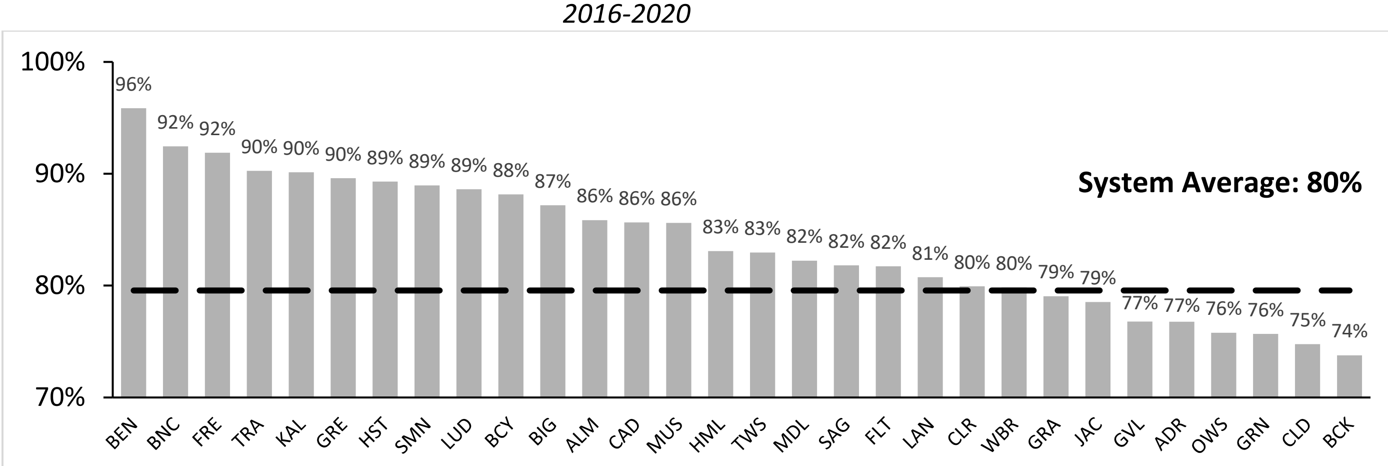
SERVICE REGION AVERAGE CELID-5, 2016-2020



Service region performance on customers restored within 24 hours of a MED interruption is shown in Figure 34.

FIGURE 34

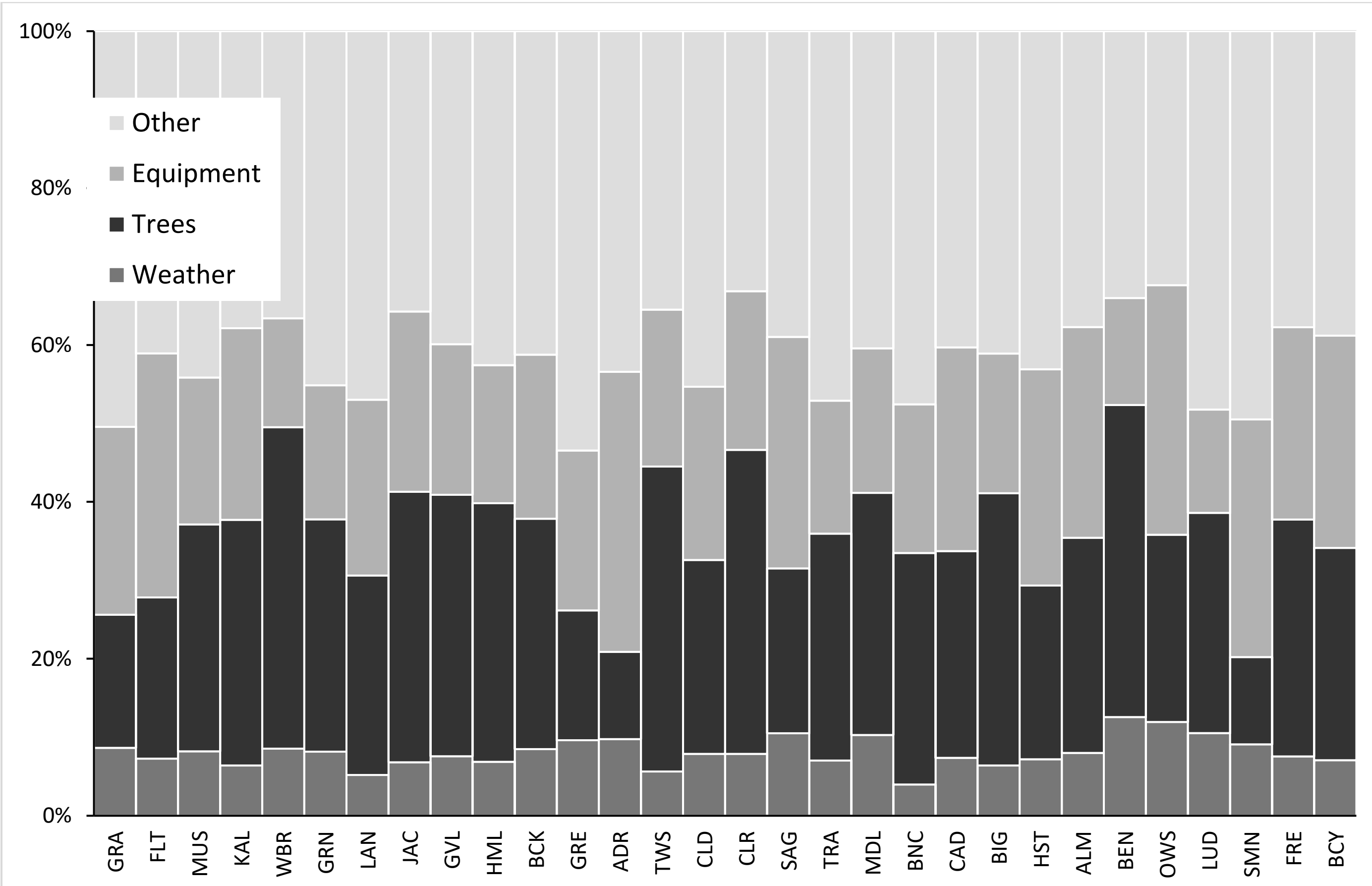
SERVICE REGION AVERAGE PERCENTAGE OF CUSTOMERS RESTORED WITHIN 24 HOURS OF A MED INTERRUPTION, 2016-2020



In addition to outage performance metrics, outage root cause analysis can help inform investment decisions at a regional level. Figure 35 shows the outage incident cause breakdown by service region, highlighting outages caused by weather, trees, and equipment failure, which are the three most prominent causes of outages. The stacked bar height shows the relative percentage of each outage cause within each service region. In looking at this information, it is important to consider the characteristics of each service region. For example, the West Branch, Tawas, and Benzonia ("BEN") regions, all of which are relatively remote rural parts of northern Michigan, have high percentages of tree-caused outages. Conversely, equipment failure represents a larger share of outage causes in some southern Michigan service regions like Adrian ("ADR") and South Monroe ("SMN").

FIGURE 35

SERVICE REGION SAIFI CONTRIBUTION BY INCIDENT CAUSE (2016-2020 AVERAGE, EXCLUDING MEDs)



All of this information on variations among the Company's service regions demonstrates the diverse nature of the Company's distribution system, from large urban areas to rural areas, and Michigan's diverse geography, which includes heavily forested areas and areas typified by flat open fields. These differences reinforce why tailored solutions are required to solve the specific reliability challenges of different parts of the distribution system.

iii. <u>Circuit-Level Performance</u>

In addition to systemwide and regional analysis, the Company also monitors performance at the circuit level to allow the Company to target investment where it is most needed. Figure 36 and Figure 37 summarize the distribution of circuit-level SAIDI and SAIFI across the distribution system. For example, 491 LVD circuits had an average circuit-level SAIDI between 0 and 50 in 2016 through 2020, while 112 circuits had an average circuit-level SAIDI over 500. 332 LVD circuits had an average SAIFI between 0 and 0.2, while 163 circuits had an average SAIFI of over 2.

FIGURE 36

CIRCUIT-LEVEL SAIDI PERFORMANCE DISTRIBUTION, 2016-2020, EXCLUDING MEDS

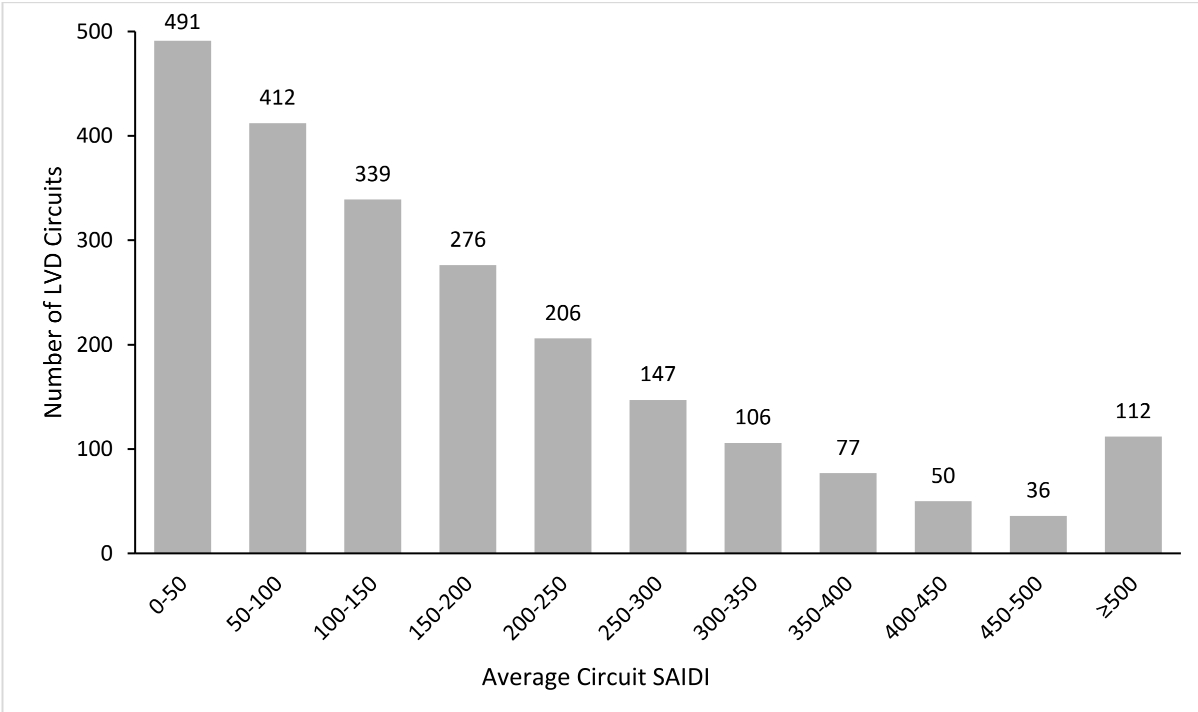
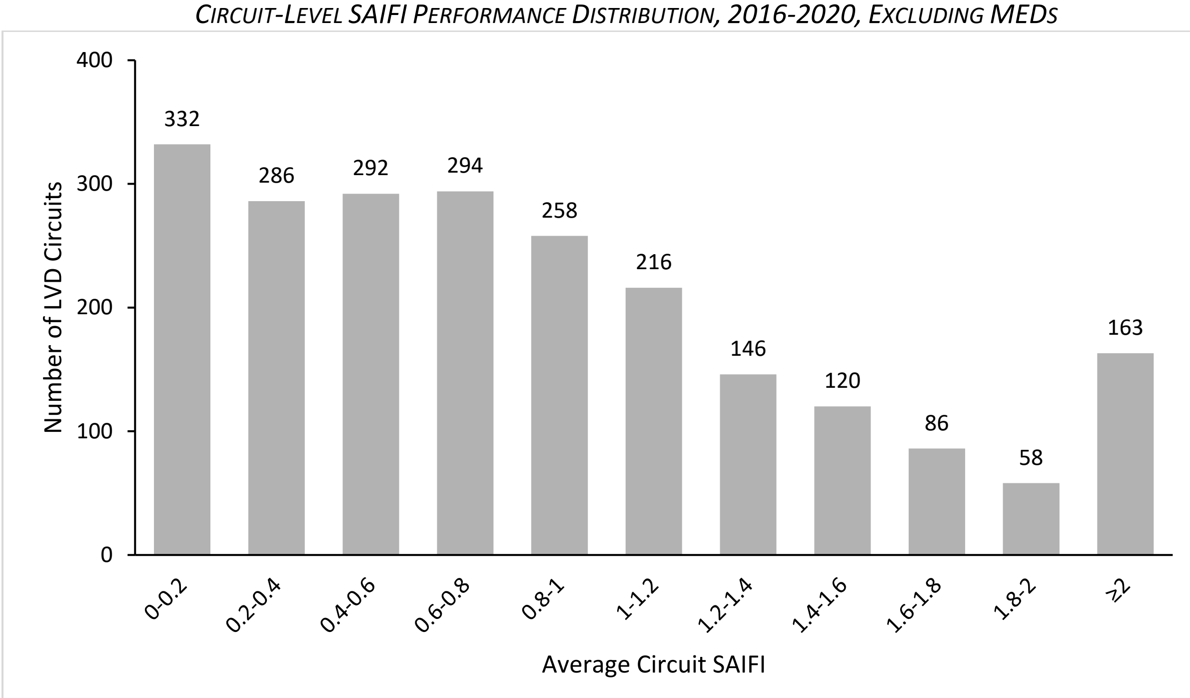


FIGURE 37

CIRCUIT-LEVEL SAIFI PERFORMANCE DISTRIBUTION, 2016-2020, EXCLUDING MEDS



As these figures show, circuits have varying degrees of reliability. The majority of circuits – approximately 55% of them – have had an average SAIDI of less than 150 minutes, well below the Company's system average, and over one-fifth of circuits have had an average SAIDI of less than 50 minutes. Conversely, just under 5% of circuits have had an average SAIDI of over 500 minutes. These distributions illustrate how a relatively small number of poor-performing circuits drive up systemwide performance levels. It also makes clear that, both to improve systemwide performance and respond to customers with particularly poor reliability, the Company should pay specific attention to the poorest performing circuits in developing targeted investments. Figure 38 and Figure 39 show the Company's ten poorest performing circuits in 2020 for SAIDI and SAIFI.

FIGURE 38

TEN POOREST PERFORMING SAIDI CIRCUITS, 2020

Substation-Circuit	Service Center	Circuit Length (miles)	Customer Count	Customer Interruptions	Circuit SAIDI
Lawrence-Christie Lake	Kalamazoo	39	442	1,783	2,275
Kolassa-Matteson	Coldwater	72	755	970	2,146
Prescott-Logan	West Branch	88	686	3,307	1,828
Lawrence-Lawrence	Kalamazoo	58	1,116	1,628	1,786
Abbe-Hwy 33	West Branch	78	748	5,406	1,706
Howard City-Morley	Big Rapids	55	842	2,956	1,497
Brooklyn-Brooklyn	Jackson	28	1,366	2,518	1,480
Steel Drive-Vista	Flint	35	1,282	2,456	1,455
Judd Road-Carmanwood	Flint	12	1,319	2,850	1,439
Vanderbilt-Wolverine	Boyne City	72	1,025	3,994	1,342

FIGURE 39

TEN POOREST PERFORMING SAIFI CIRCUITS, 2020

Substation-Circuit	Service Center	Circuit Length (miles)	Customer Count	Customer Interruptions	Circuit SAIFI
Abbe-Hwy 33	West Branch	78	748	5,406	7.23
Lyon Manor-Town Hall	West Branch	29	1,371	9,617	6.44
Wildwood-Macklin	Jackson	9	1,053	6,769	5.67
Keating-Laketon	Muskegon	12	767	4,566	5.77
Houghton Heights-Merritt	West Branch	128	2,236	12,789	5.72
Walloon-Clarion	Boyne City	12	316	1,741	5.57
Bittersweet-River Road	Hamilton	52	553	3,030	5.33
Keating-Wood Street	Muskegon	10	1,553	8,314	5.59
Price Road-Price	Midland	39	881	4,342	5.97
Hubbardston Road-Hubbardston	Greenville	38	419	2,042	4.87

When compiling data on these poor-performing circuits, the Company reviews each circuit in detail to develop specific corrective action plans targeted at dramatically improving circuit reliability. Each of the circuits identified as poor performers in 2020 will receive targeted investments and/or forestry line clearing in 2021 (and in some cases investments were already made in 2020). For example, on the Kolassa-Matteson circuit, in 2021 the Company will install Supervisory Control and Data Acquisition ("SCADA") on the Motor Operated Air Break Switch ("MOABS"), replace two pole top assemblies, and replace deteriorated equipment at 15 different locations identified during inspections.

The Company also monitors circuit-level performance for the other three primary reliability metrics. Figure 40 and Figure 41 show the number of circuits that fell within different performance bands for CEMI-5 and CELID-5 from 2016 through 2020. When circuits are identified that have an unusually high percentage of customers experiencing many outages in a year and/or experiencing long-duration outages, the Company can develop targeted investments to address those issues.

FIGURE 40

CIRCUIT DISTRIBUTION OF AVERAGE CEMI-5 PERFORMANCE, 2016-2020

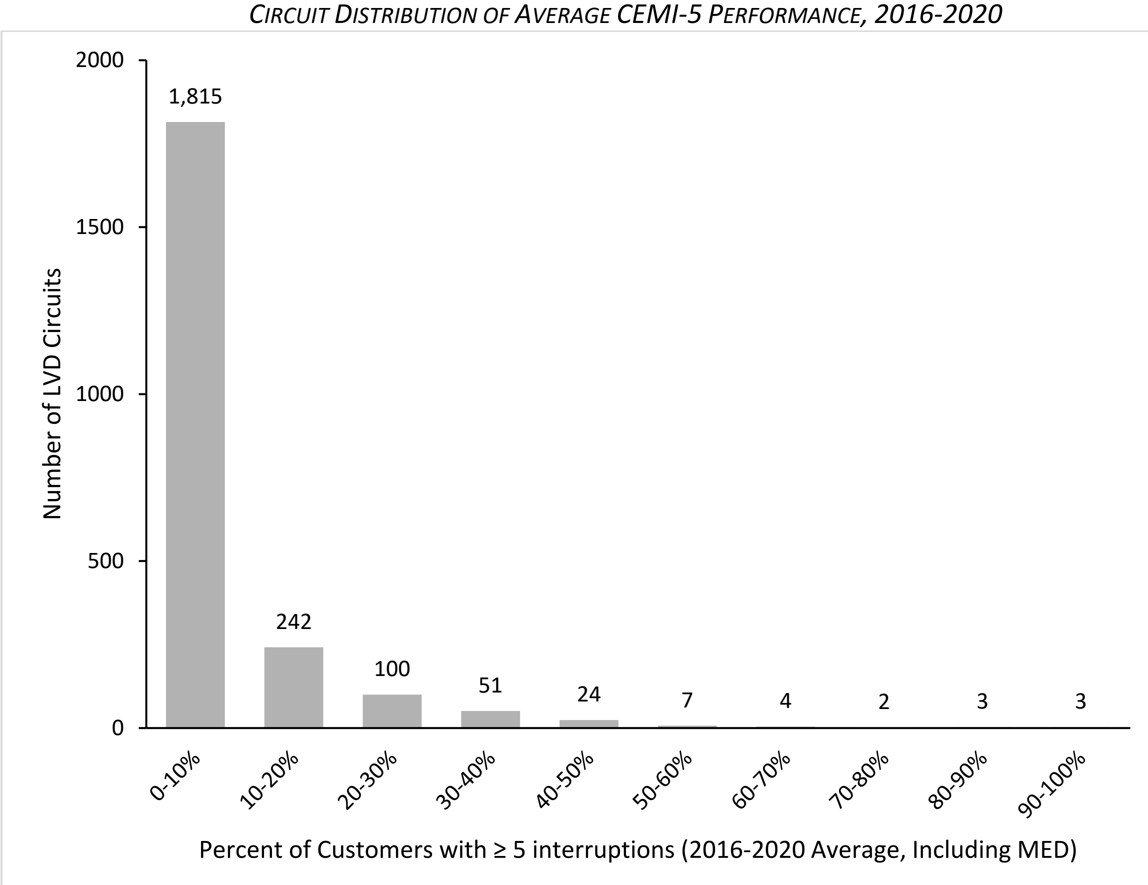
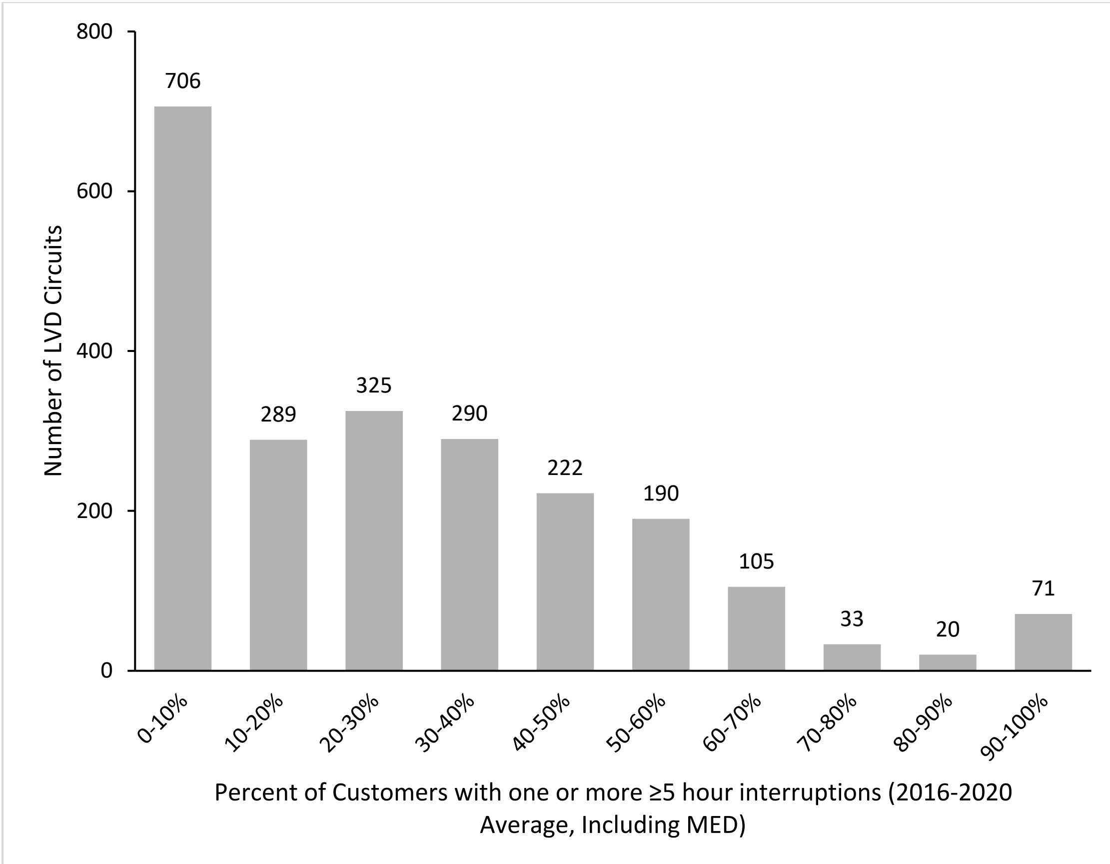


FIGURE 41

CIRCUIT DISTRIBUTION OF AVERAGE CELID-5 PERFORMANCE, 2016-2020



III. Strategic Issues

A. Approaches to Prioritization

i. Introduction to Prioritization

The Company's Electric Distribution Infrastructure Investment Planning process is integrated with utility-wide strategic and financial planning processes. Strategic planning processes, known as "roadmaps", produce strategic goals, pillars, drivers, and macro financial plans. The financial planning process, known as the Long-Term Financial Plan ("LTFP"), produces a more detailed five-year financial plan for the Company, including planned infrastructure investment projects, inspections and maintenance of existing assets, projected customer-requested and demand work and supporting staff. The LTFP is guided by and aligned with the goals and outcomes of the strategic roadmap process.

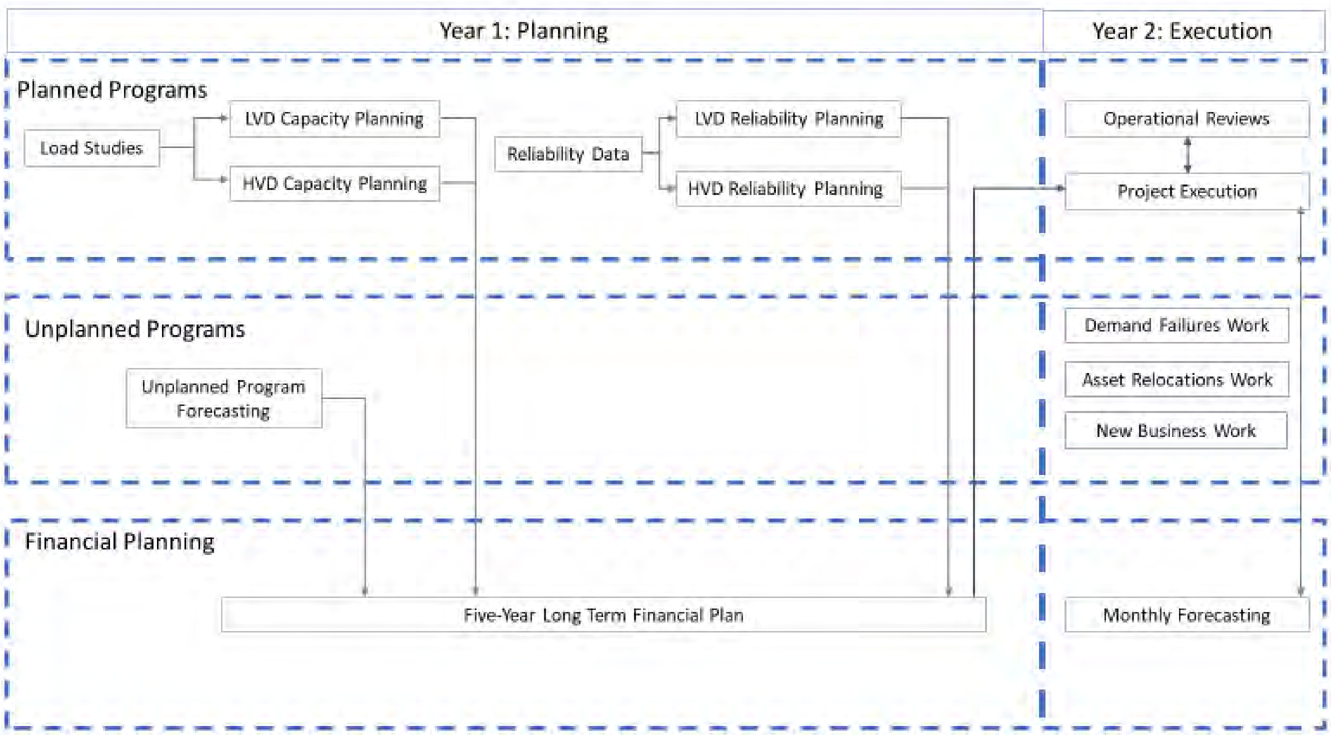
The Electric Distribution Infrastructure Investment Plan is an iterative process in which planning engineers and operators identify projects and maintenance work needed to address system performance issues and meet the Company's strategic goals and objectives for the electric distribution grid (see Section II of this report). All work is planned in consideration of expected customer demand and emergent replacements, planned maintenance, and improvements to the grid. The Electric Distribution Infrastructure Investment Plan informs the LTFP and vice versa.

In addition, the Company uses a monthly forecasting process and regular operational reviews to monitor progress and ensure alignment of financial and operational plans across the organization within a given calendar year. These ongoing planning and review activities allow the Company to respond to ongoing changes by reallocating resources to where they will have the greatest customer benefit.

Figure 42 shows how these planning activities connect over the course of the year, and this section has further details on each of the most important elements of the planning processes.

FIGURE 42

ELECTRIC DISTRIBUTION FINANCIAL AND ENGINEERING PLANNING PROCESS



ii. Annual LTFP Process

Throughout the year, program planners analyze the state of the system to assess capacity and reliability needs. Based on this analysis, planners identify work required for the following year(s) and propose projects with associated costs intended to meet individual program objectives, such as improving reliability, upgrading capacity, and responding to new business requests. See individual sections of this report on individual capital sub-program for further details of these analyses and assessments by program (note that, although not shown in Figure 42, some planning in the Company's Electric Other sub-program follows a similar principle to Reliability planning). Depending on the type and urgency of work, a given project may be identified only weeks before its execution, years before its execution, or some timeline in between.

Each summer, program planners identify expected investment needs in their respective programs for the subsequent five years, including costs and volume of work. Depending on the nature of a given program, these identified investment needs are based on a combination of pre-planned or known projects and anticipated volumes of emergent work, generally based on historical volumes of work accounting for observed trends. During the fall, the Company reviews these identified investment needs and aligns them with similarly identified needs from other utility business areas to produce, by the end of the year, a five-year LTFP. Repeating this process every year results in a rolling five-year planning process in which one incremental year is added every cycle.

The first year of the five-year LTFP is considered the budget for that year. However, the Company considers the identified investment needs and balances those, as necessary, against rate case outcomes and Commission-approved spending levels. If budgeted spending must be reduced from the level of identified needs, the Company targets reductions in such a way to prioritize essential emergent work and the highest impact planned work essentially remains intact within the plan.

For the five-year financial plan, the Company considers not only financial considerations, but also available resources. For example, ensuring that the Company will have the necessary workforce resources and other supporting resources (e.g. fleet) to execute the identified plan for any given year.

iii. <u>Monthly Forecasting Process</u>

As described above, the Company develops a budget each year, but due to factors both inside and outside the organization, actual work and spending can vary throughout a given year compared to the initial budget. Since the Company must manage its capital investments and O&M expenses across the utility portfolio, the Company assesses actual capital and O&M spending each month against prior monthly financial forecasts and budgets. Once the Company has identified spending variations, it may react by revising the program and sub-program workplans and financial forecasts for future months.

For example, the Company may have unforeseen issues obtaining easements needed to complete a project. As a result, the Company might move a different project ahead in the work plan while obtaining the easement for the original project, in turn deferring the original project until later. Although such adjustments affect the short-term work schedule, the Company manages its workplan, allowing the Company to progress toward achieving its long-term objectives.

While the Company relies on historical information and observed trends to predict work volumes, other factors, such as service restorations, demand failures, and corrective maintenance, are difficult to predict due to the variable nature of weather events, particularly storms, high winds, and ice. Emergent customer requests, particularly related to new business and asset relocations, may also fluctuate on a month-to-month basis. When this unplanned spending fluctuates, the Company reviews this information on a monthly basis and may revise its forecasts for the remainder of the year to accommodate the changes. Since the Company must allocate adequate funding and workforce resources to critical storm response, service restoration, and emergent customer needs, the Company must occasionally re-allocate funding, which can put planned work at risk of deferral. This risk can be mitigated through the use of deferred accounting mechanisms (when approved by the Commission), which allow the Company to dedicate additional funding when required for emergent work without having to reduce spending by an offsetting amount on planned projects designed to hit reliability targets.

iv. Engineering Planning Process

The Company's electric distribution engineering planning process runs throughout the year. Sections VIII and IX of this report describe specific features of the engineering planning process for each of the Company's many individual investment and O&M spending programs. The Company conducts engineering work in all programs to address specific objectives and issues on the distribution system, depending on the type of work, the affected customer profile, and the attributes of the individual system (e.g., HVD, LVD, substations).

The Company makes capital investments under two broad classifications, known as "unplanned" and "planned."

Capital investments in "unplanned" programs correspond to customer requests or emergent system needs, such as demand for new business connections, restoration of service after storms, or requests for asset relocations. These investments are not strictly "unplanned," as the Company does anticipate having to make these investments, and using a variety of external economic and industry indicators can (to some extent) forecast related volumes of work, funding required, and detailed analyses of the state of the system in advance. For example, the Company uses data from the Home Builders Association of Michigan to estimate new housing starts to help forecast future spending on new service connections. Engineering planners analyze trends by reviewing historical circuit performance and incorporate new data to help inform our short- and long-term forecasts. However, the Company is usually unable to plan specific projects until an interruption occurs, the Company receives a request from a customer, or another project-triggering event occurs.

The Company's "planned" programs proactively improve reliability, address capacity constraints, and invest in new tools and technology. In these programs, the Company prioritizes investments to maximize customer benefit in the most cost-effective manner. Specific investment prioritization varies from program to program based on each program's particular characteristics, but broadly speaking the Company uses several critical inputs and analyses to aggregate multiple data sources in order to best target and prioritize customer reliability, identifying specific investments based on the probability of future issues.

Different components of distribution planning – for example, planning for LVD lines or HVD substations – are overseen by respective program managers, who are responsible for developing plans in those areas. Under these program managers, a hierarchy of engineering planning leads and individual engineering planners have responsibilities for developing specific projects. Investment planning for the planned programs, whether for HVD, LVD, or Metro assets, broadly follows three stages:

1. **Reviewing system needs** – Engineering planners review system needs to identify critical target areas at an LVD circuit, LVD zone, LVD or HVD substation, or HVD line level, using a variety of technical inputs and analytical tools, including real-time data and inspection results. Relevant technical inputs and analytical tools are specific to each investment program and asset type;

2. **Determining required actions and developing projects** – Once a customer or system need is identified, engineering planners determine required actions and develop concepts that compare alternatives and identify a recommended project based on the most economical and effective solution; and
3. **Prioritizing and sequencing work** – Program managers and engineering planners prioritize, and sequence projects based on project timelines, customer benefits, system-wide workload balancing, and customer base balancing. The specific prioritization method depends on the program.

Details on the inputs, investment logic, and prioritization methodologies for each program are described further in the respective sections of this report on those programs. In certain investment areas, particularly for the LVD system, the Company has developed an initial step in its process for identifying and prioritizing projects, known as Grid Archetypes; the Company also uses a type of modeling called Grid MD to further validate its investment priorities. Individual projects are evaluated using a concept approval process. Each of these are discussed below.

v. Grid Archetypes

The Company has historically used various data inputs and analyses to appropriately target and prioritize customer reliability issues that must be addressed. Specific investments are identified based on the probability of future issues, with customer reliability traditionally measured by SAIDI, SAIFI, and CAIDI. Since 2018, the Company has also developed an approach, referred to as Grid Archetypes, to consider additional LVD circuit characteristics, beyond these reliability metrics, to ensure investments are optimally made across the Company's distribution system and across different capital spending programs. This approach is also meant to ensure that no section of the grid is inadvertently left behind – that both rural and urban customers, and residential, commercial, and industrial customers all benefit equitably from the Company's investments. The Company developed its first capital spending plan using the Archetypes approach for the 2021 calendar year.

Currently, the Archetypes approach is focused on the Company's LVD system, excluding Metro system assets. The Company treats its Metro system circuits as a standalone archetype, addressed by their own capital spending programs.

The Archetypes approach uses data inputs from a cross-functional group representing multiple areas of the Company, allowing the Company to better prioritize spending among a variety of potentially competing areas, as illustrated in Figure 43 below. The Archetypes approach provides a way to collectively consider data from each area to prioritize and align on an integrated investment plan.

FIGURE 43

Organization:	CUSTOMER	OPERATIONS	ENGINEERING	FINANCE	REGULATORY
How they view the grid:	• As a segmented set of customers, each with different priorities and needs, not always tied to grid assets	• As a set of operational zones within which work is prioritized and executed	• As a collection of looped and radial circuits	• As a series of programs that require investment	• As staffing, commission interactions and regulatory milestones
Most important data for determining investment priorities:	• Number and type of customers (Res, Comm'l, Industrial) • Customer characteristics and demographics	• Operational centers and zones of control • Crew scheduling • Local work execution considerations	• Asset age and history • Reliability data • SAIDI contribution of a repair or replacement	• Investment history • Short- and long-range budgets and forecasts	• Rate cases • MPSC direction

To establish the Archetypes approach, the Company first groups each of its LVD circuits into one of seven archetype categories based on various circuit characteristics. Machine learning models are then used to create segments by combining multiple data points of both numeric and categorical variables, segmenting across multiple variables without creating top-down thresholds or cut-points. Circuit characteristics include geographic characteristics (i.e., circuit line-miles, distance to Company service centers); customer mix; circuit load and voltages; and reliability metrics. Full details on all circuit characteristics and their use can be found in Appendix C.

The Company's seven LVD archetypes are shown in Figure 44 below:

FIGURE 44

LIST OF LVD ARCHETYPES

Archetype #	Archetype Description
1	Mostly large C&I customers with short circuits that are primarily underground and have the best reliability
2	Greatest mix of customers (C&I and Residential) with a high proportion of small C&I and has moderate reliability
3	Urban residential customers with short lines, high customer density, strong reliability, and high net promoter score
4	Urban customers with longer circuits and high customer density that are more susceptible to outages
5	Rural circuits with better reliability than rural circuit peers

6	Rural circuits with low customers per line mile, high frequency of outages and long outage durations
7	Rural customers with the longest circuits and poorest reliability across the system

FIGURE 45 below illustrates where each of the Archetypes are located throughout the Lower Peninsula.

FIGURE 45

VISUAL REPRESENTATION OF GRID ARCHETYPE LOCATIONS

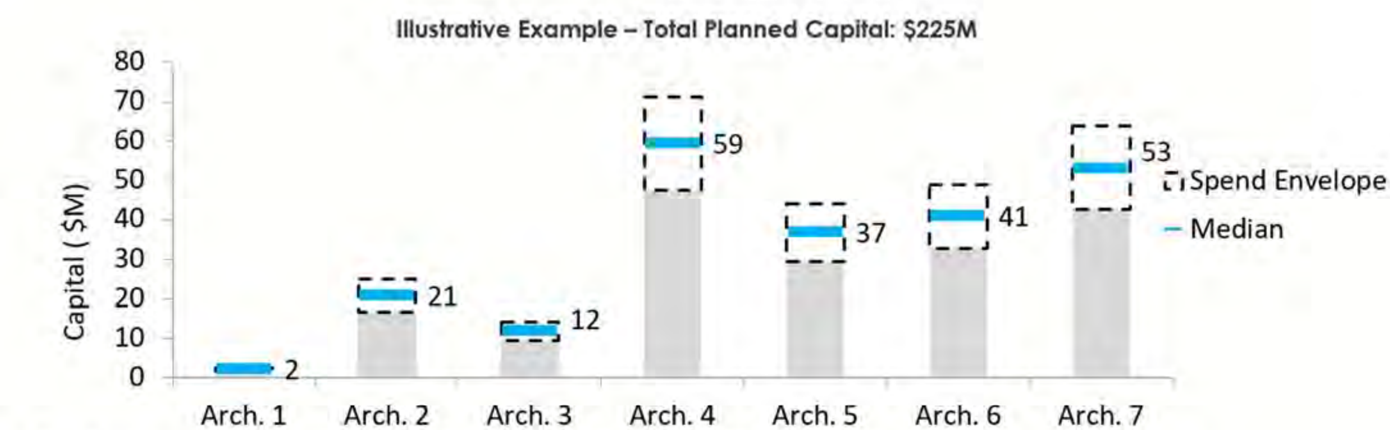
Once the LVD circuits are grouped, the Archetypes approach consists of four steps to develop an investment plan:

1. Strategic Direction: Company leadership establishes multi-year goals and broad budget guidance;
2. Prioritization: Electric Planning identifies circuits for investment in the following two years;
3. Solution Options: Electric Planning assesses a range of solutions to address circuit issues; and
4. Investment Plan: An integrated investment plan is produced.

The Strategic Direction step is intended to provide multi-year guidance on guardrails for how much investment should be allocated to each archetype. During this step, the Company takes its planned system wide LVD capital spending for a given year and allocates the spending to each archetype based on different archetype characteristics or archetype performance measures. The Company then takes the median allocation of all allocations and calculates spending guardrails for each archetype based on a certain amount of allowable variance. An example of these calculations is shown in Appendix C. The result of this process is an illustration of targeted spending ranges for each archetype, as shown in Figure 46 below.

FIGURE 46

LVD ARCHETYPE TARGETED SPENDING RANGES – ILLUSTRATIVE EXAMPLE



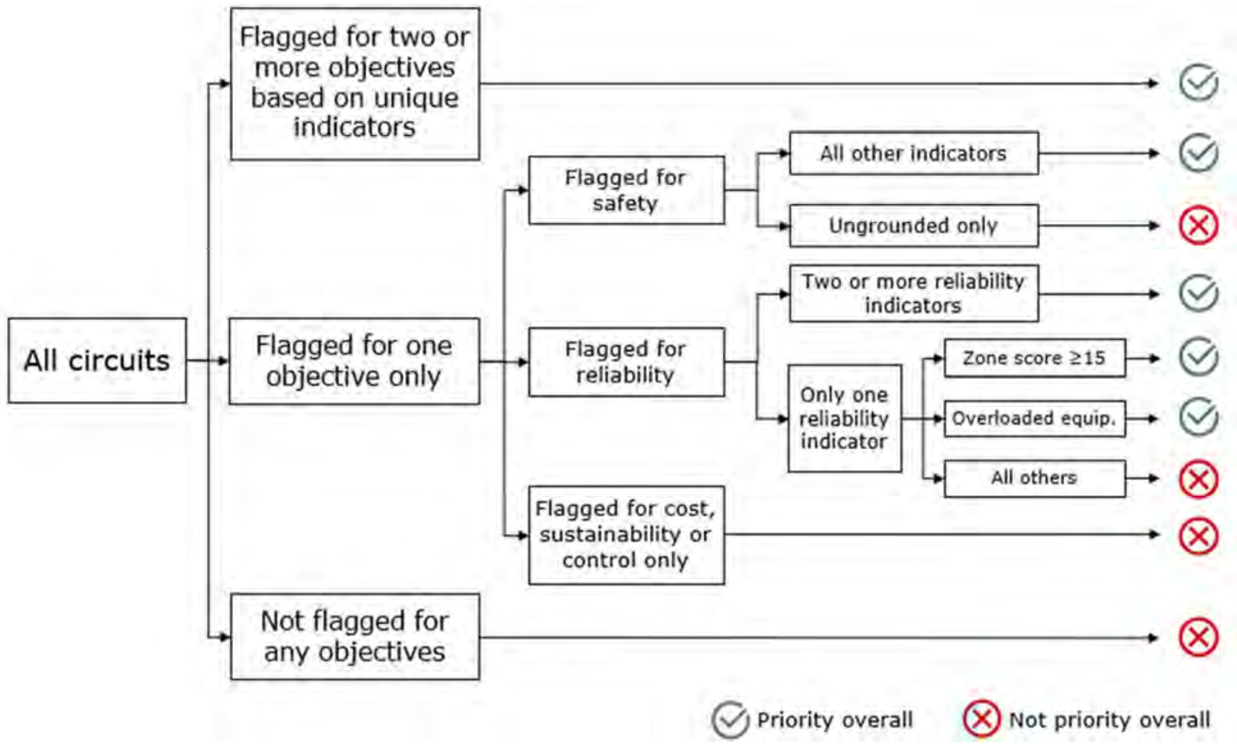
	Arch. 1	Arch. 2	Arch. 3	Arch. 4	Arch. 5	Arch. 6	Arch. 7
% customers	0.9%	8.8%	10.0%	40.0%	15.4%	11.3%	13.6%
% spending allocation	0.9%	9.2%	5.3%	26.4%	16.3%	18.2%	23.7%
Lower bound	$2M	$17M	$9M	$48M	$29M	$33M	$43M
Median	$2M	$21M	$12M	$59M	$37M	$41M	$53M
Upper bound	$2M	$25M	$14M	$71M	$44M	$49M	$64M

If the Company's planned spending in a given archetype falls outside the guardrails shown in Figure 46, then spending can either be reallocated to better ensure optimal prioritization of investment across the LVD system, or the Company can develop a justification for why spending outside of the guardrails is necessary.

In the Prioritization step, the Company evaluates each LVD circuit and flags them based on their characteristics or performance against each of the Company's five distribution objectives. Full details on the monitored characteristics and performance measures are provided in Appendix C, which shows the thresholds at which a circuit is flagged. Once the flagging is complete, the Company runs each circuit through a decision tree, as shown in Figure 47 below.

FIGURE 47

LVD ARCHETYPE DECISION TREE



As shown in Figure 47, circuits that are flagged for two or more objectives are considered "priority" circuits. Circuits that are not flagged for any objectives are not considered "priority" circuits. Circuits that are flagged for one objective may or may not be "priority" depending on the specific flags identified. Once the Prioritization step is completed, the Company has information showing the total number of "priority" circuits broken down by archetype and by type and number of flags, as illustrated in Figure 48 below. Based on this analysis, the Company can develop a pipeline of projects to address issues on the "priority" circuits. These projects are then fed into the LVD component of the Company's annual planning cadence described above.

FIGURE 48

LVD ARCHETYPE PRIORITIZATION RESULTS – ILLUSTRATIVE EXAMPLE

	LVD Archetypes								
	#1	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**	**TOTAL**	**%**
OVERALL STATISTICS									
# of Circuits	422	225	260	478	337	258	186	**2166**	**-**
# of Customers	12K	155K	172K	700K	269K	198K	242K	**1,747K**	**-**
% Residential	*41%*	*80%*	*87%*	*92%*	*88%*	*89%*	*89%*	**89%**	**-**
After Overall Prioritization									
OBJECTIVE FLAGS									
Safety	30	29	26	147	43	26	78	**379**	**17%**
Reliability	19	64	15	73	47	97	116	**431**	**20%**
Cost	40	14	14	42	8	10	68	**196**	**9%**
Sustainability	2	9	12	54	13	11	9	**110**	**5%**
Control	2	13	13	71	21	21	21	**162**	**7%**
OVERALL RESULTS									
Count of Circuits									
Number of circuits prioritized	**48**	**81**	**48**	**218**	**81**	**106**	**137**	**719**	**33%**
Number of circuits not prioritized	374	144	212	260	256	152	49	**1447**	**67%**
Count by Number of Objective Flags									
Number of circuits with 4 objective flags	0	0	0	0	0	0	3	**3**	**0%**
Number of circuits with 3 objective flags	2	6	2	16	5	4	40	**75**	**3%**
Number of circuits with 2 objective flags	39	27	16	87	28	40	58	**295**	**14%**
Number of circuits with 1 objective flag	7	48	30	115	48	62	36	**346**	**16%**

In the Solution Options step, the Company reviews the reason why each "priority" circuit was flagged and compares this to a map that identified which potential solutions will impact the relevant circuit performance measure. See Appendix C for further details on the map. This information indicates to planners which solutions may be considered for the circuit.

Finally, in the Investment Plan step, the Company creates specific projects with attached costs to implement chosen solutions on given circuits. For further information on the creation of specific projects with costs, see the discussion regarding concept approvals below. Once projects are planned, approved, and designed, the Company adds them to its sequence of work. In general, the Company prioritizes projects in the sequence based on the number and type of objective flags identified in the Prioritization step.

vi. <u>Grid MD Modeling</u>

After the Company completes its Archetypes process and begins working through the concept approval process to identify and develop specific projects, the Company uses its "Grid MD" model to assess the expected reliability benefits of its plan in a cross-functional manner.

The Grid MD model considers historical outage data, studying outage causes by asset and determining the historical SAIDI contribution of each asset type. The Company inputs projected spending for various key capital investment and O&M programs, including:

- LVD Forestry;

- LVD security assessment repairs;
- LVD targeted circuit improvements;
- LVD pole replacements;
- Automatic Transfer Recloser ("ATR") loops;
- HVD pole replacements;
- HVD pole top rehabilitation; and
- HVD line rebuilds.

For each of these programs, the Grid MD model takes the historical SAIDI contribution for each asset type, calculates expected changes given the projected spending amount, and determines an expected future SAIDI contribution. Doing so allows the Company to project future SAIDI performance based on projected investment levels. It also enables scenario planning, allowing the Company's engineering planners to understand the correlation between investment levels and corresponding reliability impact. Scenario planning proves very useful when financial plans are changed, and the Company must prioritize spending across different programs.

vii. Concept Approval Process

To ensure that its electric distribution investments are reasonable and prudent, the Company considers many of its planned electric distribution investments against alternatives and develops "concept approval" documentation to demonstrate why the selected project is the most optimal. Through this internal concept approval process, the Company ensures that alternatives were considered, and that there is a strong business case for its selected projects. The general structure of a concept approval includes the following:

1. Identification of problem;
2. Identification of alternatives, which may include capital and O&M solutions;
3. Determination of costs and benefits of alternatives;
4. Selection of best alternative; and
5. Approvals and revisions, where necessary.

Based on the Company's identified goals, program managers provide direction to the Company's engineering planners regarding the types of work that should be targeted. Engineering planners gather data and perform problem solving to identify alternatives and eventual selection of a project. Once the engineering planners have identified alternatives, selected a project, and drafted a concept approval, they are reviewed by successively higher levels of management based on the projected cost for the selected project. For small projects with relatively low cost, no approval may be needed beyond that of the engineering planning lead. In most cases, projects approved by the engineering planning lead go on to the program manager for review and approval, and may go higher than that for further review, depending on the projected cost of the project. At each level of review, the reviewing party may request further revisions.

Once a concept approval has received all necessary signatures, it is considered an approved part of the Company's investment plan. It is released to the Company's electric design engineers for detailed design work. During the design phase, costs may vary slightly from the original concept approval cost projections. If costs vary significantly (i.e., greater than 10%) based on design work, the variance may be reviewed by the program manager and engineering planner and if necessary resubmitted for approval with revised costs. If there are no significant financial variances between the concept approval and the finished design, then the project proceeds to construction. At this point, the Company's planning and scheduling group identifies and assigns either Company and/or contractor workforce resources to the project, depending on project specifics, and the project is scheduled for execution.

During construction, the program manager regularly reviews actual costs incurred against the budget. Unexpected cost variances during construction are managed through the Company's ongoing monthly budgeting process, with adjustments to the overall workplan made as necessary to manage to budget.

In some circumstances, the Company uses a charter process instead of the concept approval process. Like the concept approval process, the Company's charter process involves the same elements of problem identification, assessment of alternatives, development of costs, and approvals. Whereas a concept approval addresses a single project in an ongoing type of work, charters are used for initiatives containing many individual projects, allowing a single approval process. Charters typically contain less project-specific detail than a concept approval and are instead organized around meeting a defined end-state objective after a close-ended period of time.

Details on the inputs, investment logic, and prioritization methodologies for each program are described in the sections of this report covering each capital sub-program. Examples of concept approvals are provided in Appendix D.

B. Evolution of Metro System Strategy

i. Overview of Metro Strategy

The Company's LVD system includes a distinct component called the Metro system. This electrical Metro infrastructure provides underground distribution service in and around the downtown areas of six cities in Michigan: Grand Rapids, Kalamazoo, Battle Creek, Jackson, Saginaw, and Flint. Much of this Metro infrastructure was first installed in the 1910's through the 1950's to accommodate electric distribution in already busy downtown areas.

Metro infrastructure is used, both in the past and today, to deal with the density of downtown city centers, facilitate electrical repairs, and for aesthetics. The primary benefit is to address space limitations where numerous utilities (electric, gas, telecommunications, water and sewer, etc.) must use limited ROW in public streets and alleys, especially because high-rise buildings have greater utility needs than in lower-density areas. Because of the limited space and number of utilities, utility infrastructure must be located closer together, with greater protection, than in other locations. To provide this protection, Metro electric infrastructure is placed in duct banks encased in concrete, with transformers and switching points placed below ground in vaults. Underground vaults are necessary because cities typically use entire lots for construction ("zero lot line"), and accordingly there is not room to place transformers on poles or on the ground next to buildings.

The space remaining is consumed by sidewalks, streets, alleys, and parking lots. Metro infrastructure also allows the Company to avoid large repairs that would disrupt busy downtown centers. Installation of electrical equipment within the duct bank, vaults, and manholes mitigates the need to dig up streets and sidewalks to complete electrical maintenance, repairs, and upgrades. This provides the benefit of less community disruption. If the infrastructure was directly buried, repairs would require digging from the surface, which would close parking spots, lanes of traffic, and/or sidewalks. Metro infrastructure is also desirable for municipalities, project developers, and community members due to the limited amount of electrical equipment that is visible above the ground line, improving safety and aesthetics.

When infrastructure projects in city streets, ROW, or alleys are undertaken by any one utility, it is advantageous for all other for all utilities to consider their future needs and investment plans for that location at the same time. For example, if a municipal water or sewer utility is planning a project using underground downtown infrastructure, then an electric utility using that same infrastructure should evaluate whether it has any investment needs as well. When utilities coordinate in this manner, it not only minimizes cost for each impacted utility, but also minimizes construction-related disruption to the public.

The Company does not have strict rules regarding where Metro infrastructure is needed as an alternative to traditional LVD infrastructure. However, zero lot line construction is a common indicator of where a need will occur. Because of this, as these six downtown areas see increasing residential and commercial investment in coming years, the Company may need to expand its Metro infrastructure, accordingly, covering larger parts of a given urban area. As buildings become larger and consume more of their lot, the clearances to traditional overhead LVD lines can become insufficient to meet safety codes and difficult to maintain. The changes may be particularly driven by zoning changes. If local zoning changes to allow more construction of high-rise buildings, the area that would be best served by Metro infrastructure could grow.

As urban redevelopment continues in these areas, it also drives a large focus on aesthetics, with the developers preferring that the Company move lines underground, potentially requiring use of underground civil infrastructure to contain the electrical cabling, transformers, and other associated equipment to serve load in the area.

The Company works collaboratively with building developers during construction to ensure that buildings are properly connected to the grid and have sufficient electric service, either at the surface in open areas (where available), underground on the lot, or at ground level just inside the building. In the case of high-rise buildings, electrical rooms and conduits must be located throughout the building so that the Company can adequately provide required electric service for the numerous residential customers that are often located on the upper floors, in order to meet the tariffs, standards, and specifications for residential electric service.

ii. Maintaining Flexibility

Because the Company's Metro systems rely on underground civil infrastructure in downtown areas, Metro projects and expansions can be much more complicated that overhead LVD projects. Therefore, the Company must plan Metro projects further in advance, particularly if they require any rebuilding or expansion of the civil infrastructure, so the Company must anticipate future downtown developments.

While the Company uses various means to forecast future growth in downtown areas, including both the Company's usual load forecasting methods and Company relationships with businesses and municipal officials, it is difficult to predict the future with certainty. Because of this, and due to the complexity of many Metro projects, Metro civil infrastructure has often been built with additional capacity to accommodate future electrical cables and transformers to serve new and emerging loads further in the future. The Company's Metro planners continue to take the possibility of these new loads into account when planning investments, and the Company has begun to consider ensuring that additional conduits are installed as projects are undertaken to accommodate future uses, including additional street-side power needs by electric vehicles.

Additional conduits add much less incremental cost if done in advance when the street or sidewalk has already been dug up for an existing project, as opposed to installing too few conduits and having to expand the system even further at a later date, digging up the street or sidewalk and replace duct banks a second time.

iii. Obsolete Assets

As in other parts of its electric system, the Company plans to reduce its reliance on aged, underperforming Metro assets. Projects are initiated to improve performance, mitigate future risk of failure. Initiatives unique to the Metro system include removing lead-sheathed cable and removal of unused and unneeded vaults.

Lead-sheathed cables in the Company's Metro systems are well over 50 years old. The Company has a program to remove this outdated infrastructure that has had a known history or pattern of failures. Generally, the projects are focused on cable removal and replacement with modern cables. However, if the civil infrastructure is too badly damaged or there is not future available space, a larger project to dig and replace the civil infrastructure is necessary.

On occasion, the Company has been able to discontinue using certain electrical vaults, either by relocating assets or through asset retirements due to a diminished demand in a given area. This can result in electric underground vaults ending up abandoned or unused. To avoid future maintenance, and because these are essentially a void in the ground, it is best to ensure that they are mitigated to provide safety and security to the other infrastructure around and above the vault. Therefore, the Company undertakes removals of these vaults and fills in the remaining space with appropriate fill so that there is no longer a void beneath in the road, alley, or sidewalk.

iv. Electric Vehicles

To date, the Company has not seen a large influx of electric charging stations in the six downtown areas with Metro systems, and an influx in the next five years is not generally expected. Major electric vehicle charging developments to date have been focused near highways or on the peripheries of cities. When influxes in the downtown areas occur, the Company would need to make additional investments to expand its underground civil infrastructure to accommodate the additional electric cabling needed to serve these increased electric loads, although specific needs will depend on whether future charging stations are located street side, in parking garages, and/or in municipal parking lots. Electric vehicle loads that would need to be served in a given location could be relatively higher than the traditional commercial and residential loads that are served by the Metro system.

C. Evolution of Streetlighting Strategy

i. Description of the Company's Streetlight System

The Company owns and maintains approximately 171,000 streetlights in its service territory, generally on behalf of a customer group that primarily consists of municipal governments. This population of streetlights consists of three primary types: cobra head, post-top, and center suspension as listed in Figure 49 below. There are also a small number of mongoose and floodlight fixtures.

FIGURE 49

STREETLIGHTS BY STYLE OF FIXTURE

Style of Fixture	Approx. Population
Cobra Head	125,000
Post-Top	35,000
Center Suspension	11,000
Other (Mongoose, Floodlight)	5,000
Total	**171,000**

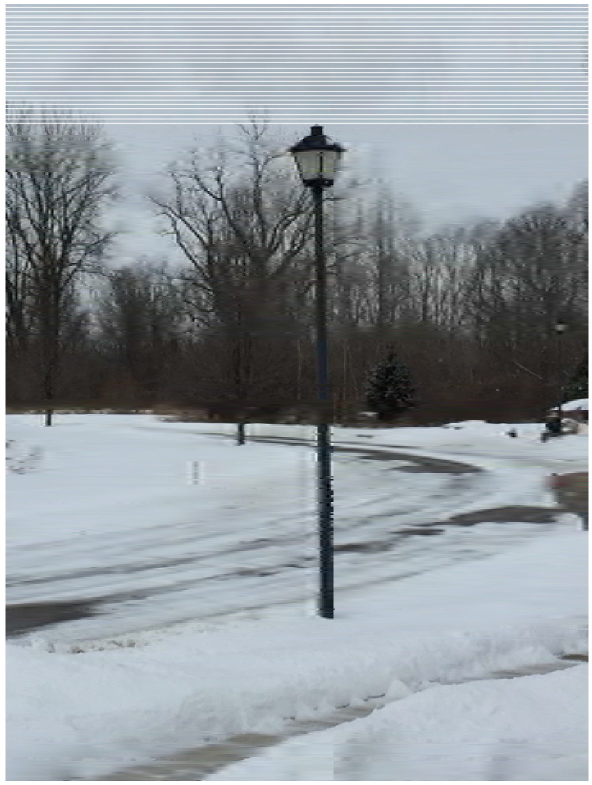
Cobra head streetlights extend out over the street from an adjacent structure, while post-top streetlights simply sit atop a structure. Center suspension streetlights are suspended over the street from wires. Each of these is illustrated in Figure 50 below.

FIGURE 50

EXAMPLES OF STREETLIGHT FIXTURE TYPES

COBRA HEAD FIXTURE

POST-TOP FIXTURE



CENTER SUSPENSION FIXTURE

FLOODLIGHT FIXTURE

MONGOOSE FIXTURE

In addition to the five different styles of streetlight fixture, the Company's streetlight system also includes different types of "luminaires" – the actual device that emits light. Broadly speaking, luminaires on the Company' system are either high intensity discharge ("HID") lights or light emitting diodes ("LED"). HID luminaires are further broken down into mercury vapor ("MV") and metal halide ("MH") devices, which each emit white light, and high-pressure sodium ("HPS") devices, which emit amber light (LEDs also emit white light).

HID luminaires make up the Company's legacy streetlight system, but MV streetlights were made obsolete by the Energy Policy Act of 2005 and are no longer produced, and manufacturers are also reducing offerings of HPS and MH devices. In any case, LED technology is more efficient and requires less frequent maintenance than any of the HID technologies, and the Company is in the process of converting its system to LEDs, as discussed in detail below.

ii. Responding to Streetlighting Customer Needs

As with any other area of the Company's electric distribution service, the Company is committed to delivering reliable streetlighting service to its customers. The Company targets restoring any reported streetlight outage within five business days. Meeting this target has important implications not only to reliably serve customers, but also to support public safety through sufficient street illumination.

However, in recent years the Company has struggled to consistently meet this target, and a relatively small number of streetlight outages requiring additional action have taken significantly longer to restore. To address this, during 2020 the Company conducted a thorough review of its streetlighting system, focusing on how outages are addressed, to develop an improvement plan. This plan includes three major components: 1) improving streetlight outage response capabilities by increasing the availability of electric service workers or contractors to perform streetlight work; 2) enhancing the Company's ability to identify and monitor outages through technology; and 3) continuing conversion of HID luminaires to longer-lasting lower-maintenance LEDs.

During 2021, the Company is continuing to engage with stakeholders through a technical workshop process to identify other potential improvements.

iii. Increased Resource Availability for Streetlight Work

The Company typically schedules 200-300 responses to streetlight outages per day, but other emergent work routinely takes a higher priority. Electric service workers are responsible for a variety of different work activities, including streetlight outage restoration. Due to the nature of the work and the potential customer impact of other service restoration work, streetlight outages are assigned a lower priority than customer reliability issues. In fact, streetlight outages have the lowest-ranked priority for responding to failures on the overall distribution system, as other anomalies generally represent a greater public safety threat and/or a larger number of customers interrupted. When responding to widespread power outages, the Company prioritizes downed power line de-energization for public safety and power restoration.

Furthermore, power outage cleanup work can often continue well beyond the period during which the bulk of customers were restored. Consequently, during and immediately following periods of power outages, streetlight repairs take a lower priority compared to power restoration. The ability for the Company to catch up on streetlight outage restoration work following a storm is often difficult and increases average streetlight outage restoration times.

To address this prioritization issue, the Company plans to increase the resources available for streetlight restoration work through both internal and external means, which may involve an increased use of streetlight contractors, and as the Company hires more electric service workers over the next several years it will have an increased ability to respond to streetlight outages.

iv. Identifying and Monitoring Outages through Technology

Beyond having a sufficient workforce to respond to streetlight outages, the Company also needs to be able to accurately identify and monitor the outages to eliminate waste by making it easier to respond to them. For example, if the Company knows that a cobra head LED fixture is out at a specific location, then workers can be dispatched to fix it quickly, without having to waste time locating the specific fixture, bringing the wrong tools or replacement parts, and so on. The technological improvements to address this issue involve both internal Company data management and a customer-facing outage reporting platform.

Internally, the Company is improving its geographic information system ("GIS") data for the streetlighting system and integrating this information with the Company's distribution asset management system; the Company's GIS was not originally designed to include streetlights. Although the Company now has accurate GIS *location* data for much of its streetlight system, the data is still largely incomplete regarding the fixture style, luminaire type, and wattage; the Company also does not yet have GIS data regarding the customer assigned to a particular streetlight. To address this, the Company will work to improve this overall accuracy over time through internal checks to reconcile GIS streetlight data with customer data.

Beyond gathering GIS data for its streetlight assets, the Company will also need to continue upgrading its overall distribution asset management system. By building a more accurate distribution system model, the Company can fully integrate its GIS data into a holistic view of the entire system, including streetlights. This distribution asset management system is essential for improving the Company's streetlighting data accuracy.

In addition to improving the Company's internal data, the Company has also developed a platform called Streetlight Outage and Reporting ("SOAR") for customers to report outages in a streamlined manner, leveraging the improved GIS and asset management information. The application went live on June 1, 2021, and simplifies customers' ability to report streetlight outages, by identifying the specific light that is out, and enables customers to monitor outage status. From a Company perspective, the application should effectively eliminate duplicate streetlight outage reports and potential duplicate site visits. In addition, the application will provide necessary streetlight outage technical information to schedulers and dispatchers, significantly reducing the amount of time that it takes to identify information such as location, luminaire type, and wattage.

The Company's analysis indicates that these technological improvements, combined with increasing workforce availability, will significantly reduce streetlight outage duration and help the Company close its overall streetlight outage response gap.

v. Streetlight Conversions

In addition to being more efficient than HID luminaires, LEDs also require less frequent maintenance. Because of this, replacing HID luminaires with LEDs will result in better outage performance over time, because fewer streetlights will fail to begin with. When electric service workers have to respond to fewer streetlight outages, they will be able to respond to those streetlight outages that do occur more quickly.

As noted earlier, the Energy Policy Act of 2005 made MV luminaires obsolete. In response to this, the Company proactively replaced almost all of its over 63,000 MV luminaires, a process that was largely complete in 2020 (the Company still has a small number of MV luminaires in center suspension streetlights, discussed below). Initially, the Company converted its MV luminaires to HPS, in order to comply with the Energy Policy Act, but starting in 2018 the Company began converting them to LEDs instead.

Also in 2018, the Company began converting all failed cobra head HID luminaires to LEDs, on a reactive basis. Through 2020, approximately 47,000 cobra head HID luminaires have already been converted to LEDs through this initiative. Because the lamps for a HID luminaire has an expected six-year lifespan, the Company expects that it will convert the remaining 70,000 cobra head HID luminaires to LEDs over the next five to six years as they fail (including luminaires that were previously converted from MV to HPS). The Company elected to convert cobra head HID luminaires to LEDs on a reactive basis, replacing them as they fail, rather than proactively replacing them programmatically, in order to keep costs lower for streetlighting customers, and because even following a reactive approach will result in converting all cobra head HID luminaires over a relatively short time horizon. Additionally, replacing them at failure is a more equitable approach for all streetlighting customers since there are no additional costs associated with the replacement, which would be the case with a programmatic approach to replacement. The Company will convert a HID luminaire to an LED on a proactive basis, if requested and paid for by a customer.

While the Company is performing cobra head conversions on a reactive basis, such an approach is not suitable for center suspension streetlights, which are unique in several ways. Center suspension streetlight bulbs are difficult to replace when they burn out. Because they are suspended over the center of the street, frequently over an intersection, replacing them requires significant traffic control efforts, with attendant municipal scheduling and permitting concerns. This creates safety concerns because crews are exposed to greater risk by having to work in the street, even when precautionary measures are taken, than they would face replacing a light on the side of the road. In addition, when a streetlight is out for an extended period of time, due to difficulties in replacement, it creates a public safety concern, as the street is not properly illuminated.

Because of these concerns, the Company plans to replace or convert its center suspension streetlights to pole-mounted streetlights on a proactive basis over the next several years. The Company began converting some MV luminaires on center suspension fixtures in 2020, typically with HPS luminaires, as equivalent center suspension LEDs are not yet identified and available. Going forward, the Company expects to proactively replace more center suspension streetlights, including those that do not use MV luminaires. Center suspension conversions are not one-size-fits all; each conversion must be individually designed to account for local conditions. For example, some center suspension streetlights could be replaced by cobra heads, but on an MDOT-maintained highway a pole must be at least 30 feet from the roadway, making a conventional cobra head unsuitable. Because these conversions must be individually designed, costs for any given conversion may vary widely, although the Company projects costs to average $5,300 per fixture over the Company's 11,000 center suspension fixtures. By converting center suspension streetlights, the Company will improve safety for utility workers and public as well as reduce the time required to repair failed center suspension lights.

Although center suspension LEDs have not yet been thoroughly evaluated and approved, the Company is evaluating the potential of using them in the future. The Company prefers to convert center suspension streetlights to pole-mounted streetlights. However, if a center suspension LED becomes viable, the Company could replace HID center suspension lights with LEDs. While they would still have the same issues faced by center suspension streetlights today, their reduced maintenance frequency would reduce the frequency of outage events.

IV. Grid Modernization and Longer-Term View

A. The Future Energy System and the Grid System Orchestrator

i. Introduction

As explained in the Executive Summary of this report, the Company is driven by its purpose to achieve world-class performance delivering hometown service, measured by a triple bottom line.

As part of this, the Company continually evaluates ways in which the electric distribution system is likely to evolve over the coming 10 to 15 years. In doing so, the Company has developed an overall strategy for the Future Energy System ("FES"), which is explained in the following section. Additionally, the Company, like many others in the industry, continues to evaluate all the impacts of FERC Order No. 2222. One outcome of that FERC Order will be to establish a coordination framework to allow DERs to participate in wholesale markets. The FES relies on both new grid technologies and evolving relationships with customers to deliver a cleaner and more efficient electrical system that incorporates more DERs, particularly solar generation and battery storage. A major component of those new grid technologies will be employed to develop the Company's Grid Services Platform ("GSP"). The Company has worked with a third-party consultant to develop a Grid Modernization Roadmap that builds on the Company's Grid Modernization achievements in recent years to develop a Grid Services Platform and other supporting capabilities, in turn enabling the FES. This Roadmap will be instrumental in the Company continuing to meet its triple bottom line, improving grid efficiency, and facilitating reduction of carbon emissions to create a more prosperous future for Michigan.

ii. Future Energy System Strategy

a) Drivers

The Company's core function does not change in the FES; it will continue to provide customers with a safe, reliable, affordable, and increasingly clean electric system and best in class customer service to benefit the people of Michigan. However, the technology that allows the Company to provide best in class service to customers is changing. The Company will increasingly provide safe, reliable, affordable, and clean electricity by leveraging DERs, including renewables, demand side management, storage, and NWS to give customers more control, convenience, and new products and services to choose from. Given these advances in technology, Consumers Energy will best serve customers by optimizing supply and demand to create the cleanest and most efficient energy system to benefit all the people of Michigan. This EDIIP, the Company's IRP, electric rate cases, and internal planning build on each other so that the Company can pursue its long-term electric strategy to provide customers with safe, reliable, and affordable electric service with best in class customer service and to enable a transition to a cleaner, more efficient, and more distributed energy system.

b) Providing best in class service to all customers

In the FES, the Company will continue to provide customers with safe, reliable, and affordable electric service with best in class customer experience. Furthermore, the Company will enhance the effectiveness of customer communications and interactions. For example, the Company is working quickly and deliberately to expand digital resources to respond to customers indicating that they prefer "self-serving" through digital channels. These enhanced digital resources will improve customers' ability to access and understand their energy usage and the various programs available to help them reduce consumption and save on their monthly bills. Customer interactions such as storm outage tracking and communications, online work scheduling, work order tracking, and many others will be greatly improved with a stronger digital platform.

In order to enhance customer convenience, control, and enrollment in various products and services the Company offers to transition to a cleaner energy system, the Company will:

- Leverage Grid Modernization and new technologies to enhance resilience, by hardening the system where necessary, improving system visibility to more proactively operate the system, minimizing outages, responding with speed and effectiveness to minimize outage duration, and better managing voltage. One of the primary advanced grid capabilities the Company is focused on to support these objectives is the automated re-routing of power flows around an outage and restoration following an outage, commonly known as Fault Location, Isolation, and Service Restoration.

- Create more individualized offerings that satisfy customer needs for cleaner and more reliable electricity or the ability to reduce costs. By using advanced data analysis and an enhanced digital platform, the Company can reach customers and engage them in the Company's Clean Energy Plan through various Company programs and services. Whether a customer wants to reduce energy usage, purchase renewable energy, or operate an electric vehicle, the Company can provide product solutions, including:
  - Energy Waste Reduction – Individualized energy consumption audits and products to lower overall consumption and monthly bills;
  - Demand Response ("DR") – Programs that reduce consumption during peak periods in exchange for lower rates and incentives;
  - Voluntary Green Pricing – Options to purchase renewable energy to offset non-renewable energy sources; and
  - Electric Vehicle Charging – Rebates on electric vehicle charging equipment and time-of-use rates to incentivize "off peak" charging.

c) Optimizing supply and demand

Optimizing supply and demand will allow the Company to better meet customer needs and increase system utilization resulting in the most efficient, lowest cost energy system. Optimizing supply and demand requires the strategies for supply, demand-side management, and asset and grid management to be fully integrated.

Supply – One of the most significant ways the Company is transforming its electric supply is by retiring large coal generation plants. Technology advancements paired with large coal generation plant retirements allows the Company to:

- Transform to a modular energy system by integrating renewables and DERs;
- Optimize the combination and location of utility-scale and distributed solar across the system; and
- Utilize non-traditional resources such as non-wires alternatives, conservation voltage reduction, battery storage, and other technologies as they become available.

Demand-side management – The Company will continue to deploy customer programs such as energy waste reduction and customer-activated demand response. Through customer engagement and enhanced customer service, the Company can leverage customer behavior as an asset in optimizing supply and demand, allowing the Company to:

- Move from customer-activated demand-side resources to automated demand management optimized for customer preferences and grid needs;
- Ensure rate design is technology agnostic and protects against customer cross-subsidization; and
- Create new programs that leverage relationships to activate customers to actively and passively execute demand-side management (e.g. automated demand response, off-peak electric vehicle charging, etc.).

Asset /grid management – As the need for precision and the number of devices and assets on the system increases, the Company's planning, operations, and customer enablement capabilities will provide increased value by optimizing a more complex system. The Company's capabilities around asset investment prioritization, asset performance management, advanced distribution management solutions (ADMS), and system automation and control are core functions, and they will be even more critical to mature in the future energy system.

Supply and demand-side management strategies cannot be implemented without a strong foundation and innovation in asset and grid management capabilities. The Company will bring its planning, operating, and customer enablement capabilities to maturity to create a Grid Services Platform (described in further detail below) that enables connectivity, interoperability, visibility, and optimization at each level of grid participation:

- Connectivity – Deploying a scalable, secure, and standardized IT infrastructure, as well as standardized, streamlined, and expedited interconnections to facilitate increased penetration of DERs and other supply resources on the grid to better enable grid services;
- Interoperability – Deploying open, secure, interoperable, well-managed, future-flexible intelligent electronic devices across all integration points among the utility, customers, and third parties to reduce risk and total cost of ownership;
- Visibility – Deploying a communications structure to provide openness, visibility, and enterprise data and analytics capabilities to local, field, and central communications; and
- Optimization – Enabling system-wide visibility and optimization, centralized and componentized optimization, coordination, and control (integrated OMS, DMS, Distributed Energy Resource Management System ("DERMS"), DRMS, short-term planning), and distributed optimization, coordination, and control.

d) Creating the cleanest and most efficient energy system

The cleanest and most efficient energy system is what is best for customers. It is the right thing to do for the planet, and an efficient system is the lowest cost system for everyone.

Clean – Asset and grid management is enabling the shift to cleaner energy resources including utility-scale and distributed solar energy as well as other DERs. The Company has committed to end coal use to generate electricity by 2040. That commitment will allow the company to reduce carbon emissions by 90 percent from 2005 levels. Further actions include:

- Reducing demand using energy waste reduction, battery storage and grid modernization tools. These "virtual power plants" will help reduce energy demand and manage customer load efficiently and effectively. They also will help keep residential customers' costs low and benefit the environment by giving customers the option to voluntarily reduce their energy use during a few peak times during the year; and
- Deploying more renewable energy including a proposal of more than 6,000 megawatts of solar energy with a ramp-up throughout the 2020s to prepare for additional plant retirements and the expirations of power purchase agreements.

Efficient – The Company will continue to optimize operations to be leaner and lower cost for customers through use of a lean operating system. In addition to using a lean operating system, optimizing supply and demand increases system efficiency and is the lowest cost solution for the future energy system. Although the future energy system will be more complex and sophisticated than it has been historically, Company expertise will provide the lowest cost grid solutions for all, using tools including:

- Supply/demand balancing;
- Reducing losses;
- Conservation voltage reduction; and
- Engaging customers in demand-side management as mentioned above

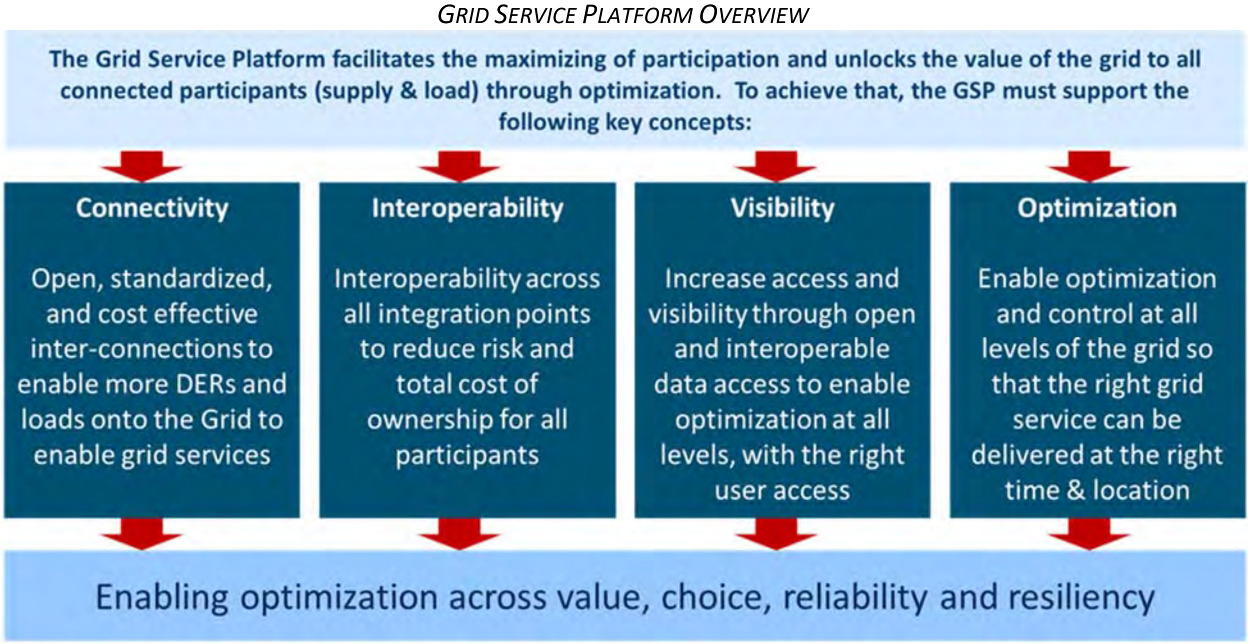
iii. Grid Services Platform ("GSP") Overview

The Company's distribution system is becoming more automated and will increasingly rely on DERs as a source of electric supply. To continue to deliver reliable, safe, and cost-effective electricity, the distribution system will require new business functions; more efficient planning, design, and operations; and advancements in communications, controls and coordination technologies that will enable grid systemwide visibility and optimization. Consumers Energy, in partnership with the third-party consultant that helped develop the Grid Modernization Roadmap, developed the Grid Services Platform concept to technically enable a distribution system to effectively integrate increasing amounts of DERs. The Grid Services Platform concept provides a common strategic framework to align the overall grid modernization initiatives across the Roadmap, providing a clear path forward. The Company's Grid Modernization Roadmap, discussed below, addresses gaps between the current state of the grid and the future state represented by the Grid Services Platform. The Roadmap is designed to create new capabilities that enable the development of the Grid Services Platform.

The Company and its third-party consultant defined the Grid Service Platform to apply the technologies required to enable the integration of increased DERs over time.

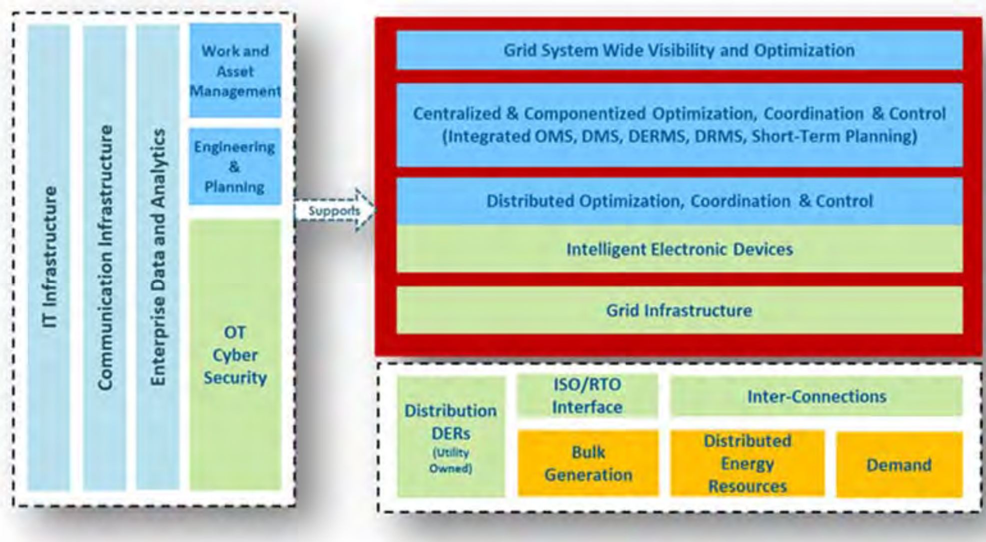
FIGURE 51

GRID SERVICE PLATFORM OVERVIEW



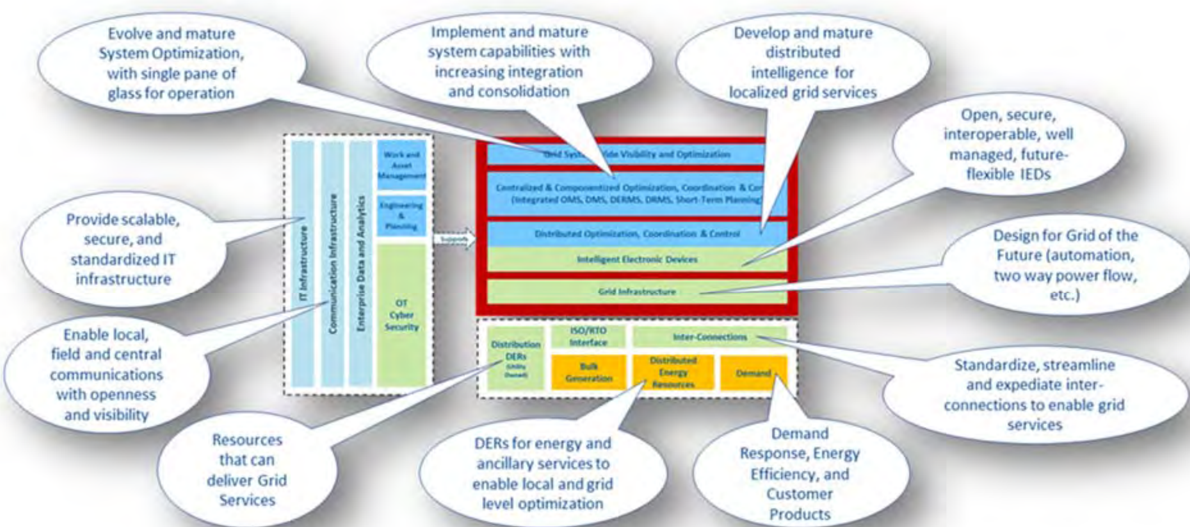
The GSP will enable the Company to deliver the most reliable, resilient, sustainable, flexible and affordable power services while enabling customer choices and delivering societal benefits.

FIGURE 52
GSP ARCHITECTURE



To achieve the lowest total cost of ownership and maximum value, the GSP must be interoperable, secure, reliable, flexible, and able to optimize at each level of grid participation.

FIGURE 53
GSP GUIDELINES



B. Recent Grid Modernization Achievements

In the Company's 2018 EDIIP, it established an initial framework for Grid Modernization, discussing new capabilities that the Company would develop and the first phases of device deployment to enable those capabilities. While the Company's plans have progressed to include an even broader Grid Modernization program, as discussed later in this section, the Company has made tremendous progress toward the Grid Modernization-enabled foundational reliability and system optimization improvements established in the 2018 EDIIP. The Company continues to deploy Distribution SCADA, automation loops, Conservation Voltage Reduction ("CVR") and ADMS programs that were discussed in the 2018 EDIIP and subsequent electric rate cases. As noted below, several of these components are necessary to enable Fault Location, Isolation, and Service Restoration ("FLISR") and Volt/Var Optimization ("VVO").

FLISR allows the Company to quickly and automatically restore power to as many customers as possible, without requiring intervention by Company operators or crews. FLISR can detect a fault on the system and then automatically operate switches and reclosers to isolate the fault and transfer as many customers as possible to being served by an alternate substation or circuit until the fault can be addressed. This reduces outage durations for customers and reduces outage costs for the Company by reducing demands on service crews.

VVO enables coordinated control of voltage regulators and switched capacitor banks to reduce system losses and eliminate waste, using regulator controllers, capacitors, distribution supervisory control and data acquisition ("DSCADA"), and ADMS. Without this capability, the Company must maintain voltage at the substation near the upper threshold of MPSC standards in order to ensure that voltage is delivered at a high enough level to customers once line losses are accounted for. By replacing regulators and capacitors, the Company can improve its voltage performance by reducing line losses. The major benefit of VVO is that it reduces line losses, enabling CVR, which provides a reduction in energy consumption, as discussed below.

CVR

CVR is the capability to optimize service-point, or customer meter, voltages to reduce energy demand without requiring active participation or behind the meter investment by customers. CVR uses a set of technologies, including VVO, that reduces the delivery voltage along LVD circuits, thereby reducing the amount of electric load that must be served on the LVD circuit, and thus, on the electric system. The technology works together and optimizes control settings on both substation and downstream voltage regulating equipment. The technology allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction while staying within the regulatory requirements. Because CVR provides both grid benefits and electric supply benefits, it was included in the Company's 2018 Integrated Resource Plan and was subsequently established as a sub-program in the Company's Capacity distribution capital program. CVR technology has been deployed on 108 circuits through the end of 2020, with 52 more planned by the end of 2021. This year the project team has focused on building the program and creating sustainable standard processes and procedures.

ATR Loops

ATRs are a key component for enabling distribution automation loops on the system. This technology is installed in sets on the system between two LVD feeders creating an automation loop, with three to five

ATR devices being installed on a typical LVD circuit. ATRs transfer load automatically in the event of an outage, reducing customer outages and improving system reliability by isolating a faulted section of a circuit. When an ATR operates during a distribution event, the fault on the distribution system is automatically isolated and the rest of the customers are automatically restored within 90 seconds. ATR deployment is coordinated with DSCADA deployment, with the two classes of device being integrated by ADMS, all of which is critical in enabling FLISR. Today, there are over 81 loops in service. In 2020 alone, there were 49 instances in which an ATR loop operated, avoiding 9.1 million customer outage minutes and preventing over 33,000 customers from experiencing an outage.

DSCADA

DSCADA is the key component of LVD substation automation, allowing the Company to open and close substation devices remotely without having to send a human operator. When DSCADA is installed at a substation, it includes a Remote Terminal Unit ("RTU"), a local device that facilitated communications with substation devices and remote software systems and captures over 300 data points within the substation and uses a cellular modem to transmit the data to the Company's operators. The enhanced visibility into substations and the remote-control capabilities together allow the Company to address outages more quickly and effectively. By enhancing visibility, DSCADA allows the Company's distribution planners to perform more accurate load flow studies, because DSCADA provides access to real-time circuit data; load flow studies can therefore be dynamic based on time of year or day. The remote-control aspects of DSCADA are crucial in enabling CVR, FLISR, and VVO capabilities, and in making ATR loops operable.

The Company has deployed DSCADA at 494 substations with several hundred more planned over the next couple of years. This adds up to well over 1,000 circuits that have DSCADA enabled today.

Line Sensors

Line sensors are devices that attach to primary lines to monitor current. They can detect faults and determine a probable location of a fault event, making them critical in enabling FLISR. Line sensors also provide information such as circuit loading, circuit balance, fault current data, momentary outages, permanent faults, line disturbances, and high current alarms. In addition to operational capabilities, line sensors can be used to improve the entire LVD planning process by allowing more accurate load flow modeling. Not only can sensors improve the model for the circuits where they are installed, but the analysis performed using the data from line sensors can be used to improve the Company's load model statewide. This more accurate and near real-time load information can be used to improve the load transfer process both for planned and unscheduled outages. This will reduce the duration of the manual load transfer writing process and improve the accuracy of the modeled transfers. Data is transmitted to Company operators using the cellular phone network.

The Company has installed over 2,500 sensors on the LVD system. Over the next five years, the Company plans to have over 11,000 sensors installed. In 2020, the project team was dedicated to the deployment of the new Sensor Management system and the integration of line sensor data into the DSCADA system. The new Sensor Management system provides additional valuable data such as fault oscillography, conductor temperature, phase misalignment and more. Having this load and fault data in DSCADA will be a critical component for the implementation and operation of FLISR.

ADMS

The ADMS has progressed according to the Company's implementation plan. The merger of Distribution Management Systems ("DMS"), DSCADA, and Outage Management Systems ("OMS") into a single integrated platform enables the individual pieces to operate better as a whole. Each component benefits from the share inputs and operational capabilities of the others.

The Company has already met several milestones in the ADMS project. These include delivering an electronic system map ("eMap") and Distribution Power Flow ("DPF") for an initial subset of circuits in September 2019; delivering a model based VVO in March 2020; and Operator Training Simulator ("OTS") in June 2020. These were the first three of five targeted releases included in the DMS part of the project. The remaining two functionalities are being delivered in 2021. The project team is delivering FLISR in two pieces, with Fault Location ("FL") in late 2020 and Isolation and Service Restoration ("ISR") in 2021. In addition to the ISR release, the Company will deliver Switch Order Management ("SOM") at the same time. DPF and eMap allow operators to monitor current grid conditions and take appropriate actions as conditions change. FLISR and SOM allow distribution operations to expedite service restoration through automated means where possible and through improved targeted efforts in areas where automation isn't possible. The OTS allows the Company to train operators in situations that mirror real life scenarios.

For OMS, the Company will have one release of this functionality in 2021. The project team has worked through the majority of OMS systems configuration and is beginning to formally test the application. The OMS functionality will be fully connected to DSCADA and DMS operations allowing the Company to quickly and precisely determine fault locations and target our response.

C. Forward-Looking Grid Modernization Roadmap and BCA

i. Overview

Consumers Energy has established itself as a leader in providing clean energy to its customers by setting a goal of net zero carbon emissions by 2040. The Company also committed to several renewable energy supply goals in its 2018 and 2021 IRP, including, for example, 6 GW or more of solar capacity. Overall, the Company's clean energy strategy calls for doubling customer efficiency programs and aggressively shifting from centralized, fossil fuel generation sources to an integrated portfolio of renewable resources at both the bulk and distributed level, including storage.

To facilitate this transition, Consumers Energy has started to integrate its electric generation and distribution organizations into a single integrated engineering organization, called Electric Grid Integration, with a set of workstreams across multiple business functions to ensure progression toward integrated planning and design. These workstreams specify investments in areas such as grid modernization, infrastructure, and planning and operational capabilities. From a distribution grid point of view, the Company has developed the GSP concept as a core capability that will be essential in managing this shift in Company strategy, especially as increased penetration of DERs is expected in Consumers Energy's service territory in the near to medium term. In order to enable the GSP, the Company has developed a Grid Modernization Roadmap, outlining all the investments and activities needed to deliver this outcome.

ii. <u>Purpose of the Grid Modernization Roadmap</u>

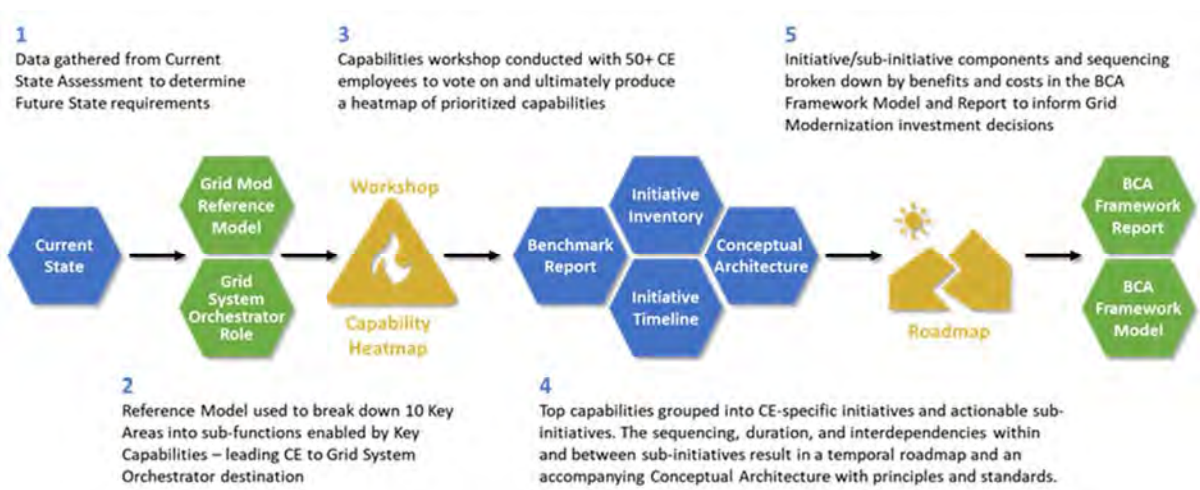
The Company has been deploying Smart Grid technologies, including advanced metering infrastructure ("AMI") and DSCADA, for over a decade, establishing a foundation to allow more diverse supply and demand resources to be connected to its distribution grid. The Company will continue investing in infrastructure initiatives that are currently underway, such as DSCADA, CVR, and ADMS programs.

Consumers Energy's Grid Modernization activities are now at a point where adjustments and additional investments are needed to further enhance the capabilities, reliability, and resilience of the grid. As a result, the Company worked with a third-party consultant to refine and develop its Grid Modernization Roadmap, looking two, five, and 10 years into the future. The resulting Grid Modernization Roadmap ensures that Consumers Energy's future investment plans can build upon its current strong infrastructure foundation, leverage the utility industry's technology advancements, and provide the Company with a concrete plan for transforming itself for the future, as discussed above. This effort will allow the Company to close the gaps between its current state and desired future state by: 1) concrete plans around foundational investments; 2) identification of inter-dependencies and potential gaps; 3) a framework of business case analysis; and 4) coordination and integration of many aspects of the Electric Grid Integration and other Company-wide strategic goals in order to maximize the value of its grid modernization investments.

iii. <u>Scope and Approach</u>

Consumers Energy engaged a third-party consultant to help develop its Grid Modernization Roadmap, in a process focusing on the key areas of Substation Automation, Distribution Automation, DER Integration, ADMS, and Distribution Asset Management. The methodology and key deliverables are depicted in Figure 54 below.

FIGURE 54



The overall Roadmap development approach was grounded in the following key principles:

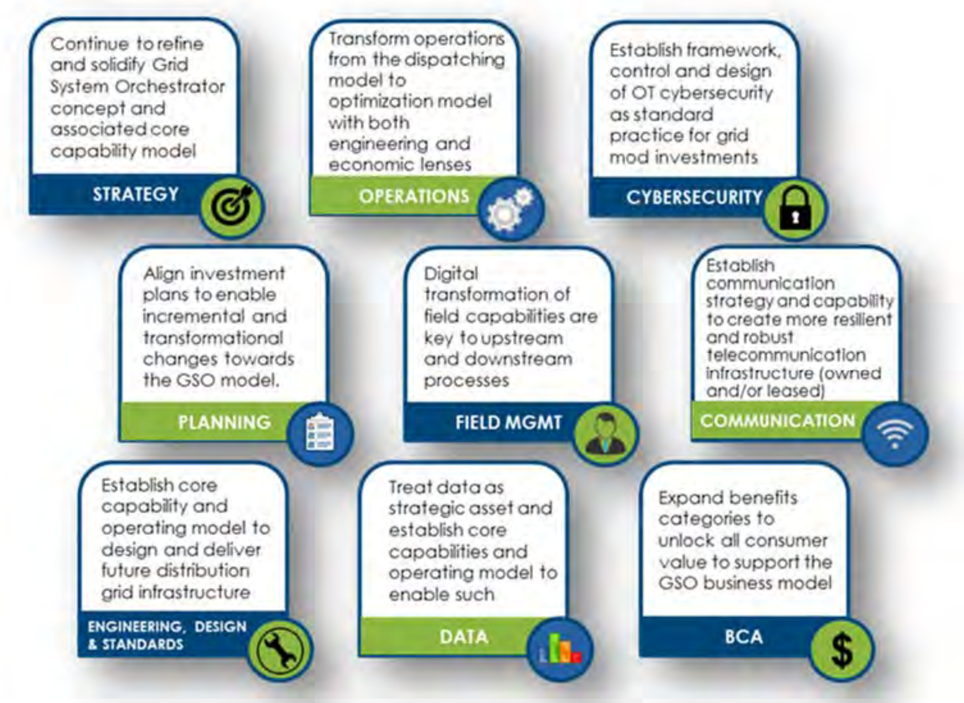
- The Roadmap starts with a thorough understanding of the current state, identifying on-going efforts and gaps;
- It builds on a future state vision that is driven by both the industry leading practices and Company-specific corporate strategy and business goals;
- The scope of the Roadmap initiatives is comprehensive and includes both foundational grid modernization investments as well as critical supporting investments needed to ensure benefits achievement and maximization;
- The Roadmap initiatives are well-aligned to deliver high value capabilities across Company organizations;
- The Roadmap initiatives are sufficiently detailed to create a time-based and evolutionary view (two, five, and 10 years) that can be maintained and updated as it evolves over time; and
- A comprehensive Benefit-Cost Analysis ("BCA") framework and spreadsheet allows the Company to ensure and demonstrate the prudence of its Roadmap investment and to ensure investments deliver tangible value to the Company, its customers and society, documenting the realized benefits of Grid Modernization initiatives and comparing those benefits to associated costs.

Adhering to these principles ensures that the Roadmap is detailed, tailored, executable, maintainable, and reasonable and prudent as the Company develops its plans.

iv. Highlights of the Roadmap

The overall objective of the Roadmap is to help the Company cohesively plan, develop, and deploy Grid Modernization investments while aligning and optimizing realization of benefits. While some of the Company's Grid Modernization efforts to date have focused on either pilot applications or on the initial deployment of automation technologies, the Grid Modernization Roadmap expands beyond these transitional grid modernization technologies to focus on integrating them into day-to-day distribution planning and operation. Twenty-two initiatives are identified in the Roadmap, representing several categories of investments that will work together to enable the Company's GSP functionality. These include initiatives for business model and platform capabilities; operational capabilities; infrastructure improvements; engineering and planning capability advancements; work execution capabilities and data management capabilities. The Roadmap includes a set of capabilities in the following nine areas highlighted in Figure 55 below. These capabilities will be critical for enabling the GSP.

FIGURE 55
ROADMAP KEY FOCUS AREAS



Strategy: Continue to refine and solidify strategy and associated roles, functions and capabilities which will serve as the North Star for the execution and evolution of the Roadmap;

Operations: Transform the business from a traditional dispatching-centric model to a real-time operation and optimization model with unified visibility and control across its grid, including enabling distributed intelligence and control where needed;

Cybersecurity: As the grid modernization deployment scales up, operational technology cybersecurity should be an integral part of the overall design, deployment, and operation of the grid infrastructure. Therefore, it is critical to establish cybersecurity standards and control framework up-front and integrate this capability into the future grid modernization deployment to reduce cyber risk and avoid future system rework;

Planning: Integrated Systems Planning across the traditional resources and DER will require further integration between resource planning, systems planning and asset investment planning, as the Company evolves. This will require more granular and integrated data and information to address regulatory needs, as the amount of DER increase over time;

Field Management: As the distribution grid evolves to enable more resources and more dynamic demand at the edge of the grid, the grid operation will become more modular, distributed and dynamic as well. This will require increased frequency and accuracy of data and information from the field. Digital transformation of field work and asset management will be an integral part of enabling grid modernization investments to realize their full benefits;

Telecommunication: Field communication infrastructure will be very critical to the future grid performance at all levels (i.e., local device automation, field automation and central grid operations and control). Having a secure, robust and resilient communication infrastructure is a must. Consumers Energy should review its long-term telecommunication strategy, especially regarding the security and resiliency aspects of its networks;

Engineering, Design and Standards: Future distribution infrastructure will require modern substations and circuit designs with digital intelligent devices and distributed automation. Engineering design and standards will need to work together with grid modernization and operations to create the substations and circuits of the future;

Data: As more distributed resources are connected at the grid edge and as supply and demand become more dynamic, more control decisions will be automated either locally or centrally. This will require a much higher level of granularity, fidelity and speed of data and information to drive operational optimization. Data management and governance across the distribution business will be essential to meet the operational requirements of the future; and

BCA: The ability to articulate and demonstrate the overall value of investments from utility, customer, and societal perspectives is key to securing regulatory support and approval of the investments needed for the grid transformation. As Consumers Energy moves forward with efforts to achieve its clean energy goals, having a comprehensive BCA Framework and related computational basis (the BCA Framework Spreadsheet) will allow Consumers Energy to demonstrate prudence and value over time to its regulator and stakeholders.

In developing the Roadmap, key capabilities were prioritized and grouped into specific initiatives. These initiatives were then broken into actionable sub-initiatives. Each initiative was documented using a detailed template (see Figure 56) to standardize the evaluation process. A total of 22 initiatives (see Figure 57) were created with a total of 94 sub-initiatives.

FIGURE 56

INITIATIVES TEMPLATE

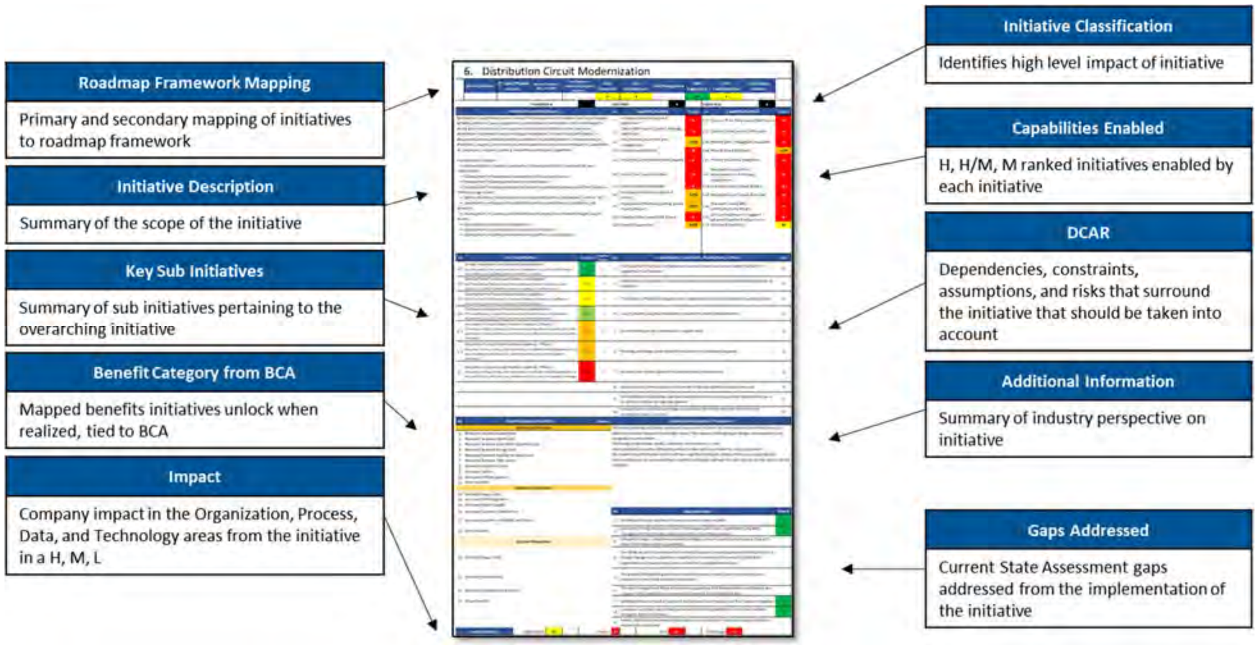


FIGURE 57

INITIATIVES LIST

ID	Initiatives	Definition
1	ADMS	Completion of existing scope of ADMS program
2	Expansion of ADMS Beyond Existing Scope	Extending ADMS program capabilities to the remainder of the LVD electrical footprint
3	DERMS	Implementation of an at scale DERMS solution
4	DRMS	Modernization of an at scale DRMS solution
5	Substation Modernization	Improve control and automation functions including IT, OT, telecommunications, and power devices
6	Distribution Circuit Modernization	Evolve the development of standards and circuit designs, including materials, power equipment, and Distribution Automation (DA) technologies to enable grid orchestration
7	Distribution Device OT Cyber Security Management	Configuration management, standardizing security hardware, and access control on all devices
8	Manager of Managers	Integrated visualization of telecommunication and power electronic devices
9	Distribution System Operator Business Model	Strategy, roadmap, design, and market readiness
10	Distribution System Operator Service Platform	Developing scalable layered architecture to enable the DSO
11	Accelerate DER Interconnection Process	Improve the scalability and robustness of DER interconnection processes including hosting capacity
12	Distribution Asset Management	Asset, work, and maintenance management processes including the development of a common asset data model, IED asset lifecycles, and an asset data repository
13	Distribution Device Management	Develop the organization, skills, policies, processes, applications, and solutions to manage distribution devices and associated IEDs
14	Asset Performance Management	Development of analytics and algorithms to monitor and measure and predict asset performance (substation, distribution, and IEDs)
15	Asset Investment Planning	Risk based and archetype-based planning to optimize investments
16	Field Work Digitization and Mobility	Simplifying field work and provisioning of hardware and systems to improve efficiency and asset data quality
17	Field Work Scheduling, Planning, and Optimization	Aligning organizations, processes, and existing applications to create an optimized planning and scheduling process
18	Contractor Work Standardization	Optimizing contractor asset and work management processes to support the common asset data model and digital work processes
19	Integrated System Planning	Coordinated integrated resource planning that includes distribution, generation, archetype and circuit transition planning
20	Distribution Data Governance	Policies, procedures, and controls for all distribution data
21	Distribution Data Management	Management capabilities, processes, and tools for all distribution data
22	Establish Grid Mod Incubator	Test bed for Grid Mod technology

The first phase (0-2 years) of the Roadmap focuses on catching up with certain foundational capabilities such as device asset management, OT cyber security, and data management, while continuing to develop ADMS capabilities and pilot others such as a DERMS. The second phase (2-5 years) focuses positioning the Roadmap initiatives toward the initial formation of GSP capability and core operational and planning capabilities. Depending on how evolving market conditions and regulatory processes affect the pace of grid transformation, inauguration of the full GSP capability will begin to take shape in the third phase (5-10 years), focusing on integrating, consolidating, and enhancing advanced features and functions. Each of these phases is illustrated in Figure 58 below.

FIGURE 58

ROADMAP HIGHLIGHTS

The Company invited Electric Power Research Institute ("EPRI") to perform an independent analysis of the Company's Grid Modernization Roadmap. The full analysis is provided in Appendix E of this EDIIP.

As EPRI's analysis indicates, the Grid Modernization Roadmap incorporates industry-standard or industry-leading practices and positions the Company well for the future. EPRI's analysis also provides several recommendations for further improvements, which the Company will incorporate going forward.

D. Grid Modernization Roadmap BCA

The primary purpose of the Company's Grid Modernization Roadmap BCA is to estimate the costs and quantitative benefits of Grid Modernization investments and evaluate these estimates through a multi-period overarching benefit-cost framework, as well as to describe the additional qualitative benefits.

The Company developed a framework for its Grid Modernization Roadmap BCA in concert with the third-party consultant used by the Company to help develop the Roadmap itself, in order to guide the Company's efforts to identify and quantify the costs and benefits associated with its Grid Modernization initiatives. This framework provides a comprehensive structure and detailed spreadsheet approach to accommodate each of the Roadmap's Grid Modernization initiatives and sub-initiatives.

This BCA is particularly important in how it captures the interdependencies of various initiatives and the complex interaction of benefits achieved from the different combinations of programs and funding levels for each. Using the BCA as a guide ensures optimal investments are being made to benefit customers, clearly establishing the short-term and long-term merit of proposed investments.

The BCA framework will be integrated into ongoing Grid Modernization planning and deployment processes. The BCA framework provides a methodology for calculating the benefits and costs resulting from deployment Grid Modernization projects and programs. The direct cost and benefit impacts will often depend on how and/or in what order the projects are implemented. The BCA framework provides a foundation for both planning and for validation of realized Grid Modernization benefits, connecting them to specific project initiatives over time.

The BCA framework, as presented in this report, is not intended to provide a full BCA for the entire Grid Modernization roadmap, which consists of many investments over a ten-year period. As a *framework*, it is meant to provide a tool to measure the costs and benefits of particular initiatives and projects as they are further developed in detail, which is why the framework will be increasingly integrated into planning and deployment of Grid Modernization going forward.

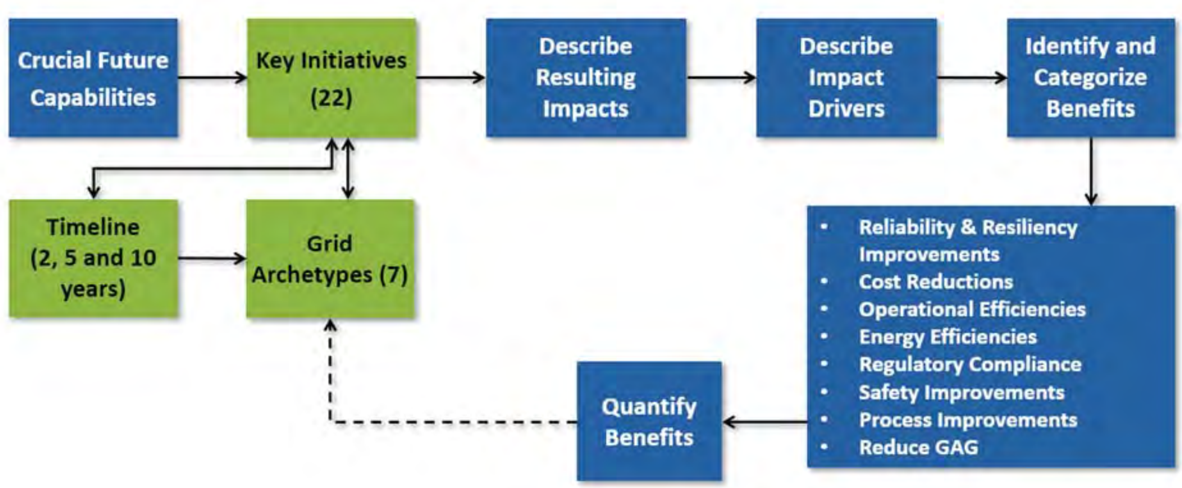
Applying the BCA framework to every Grid Modernization Roadmap initiative immediately would require significant assumptions. The BCA framework is designed to incorporate solid data as it becomes available. To demonstrate that the BCA framework works, the Company has already used it on one initiative, Distribution Circuit Modernization, and the results of this are provided in the illustrative example later in this section. Going forward, the Company expects to apply the BCA framework on a more prospective basis to support Grid Modernization business cases.

i. <u>BCA Structure</u>

A well-designed BCA requires standardized results and a repeatable structure to enable consistent evaluations for all programs and initiatives. Initiatives, both now and in the future, will have varying types of costs and benefits, so a robust process to account for these differences can ensure consistency of evaluation, using a model that can easily be tuned in the future to consider the weight and importance of various qualitative benefits.

FIGURE 59

BCA FRAMEWORK STRUCTURE

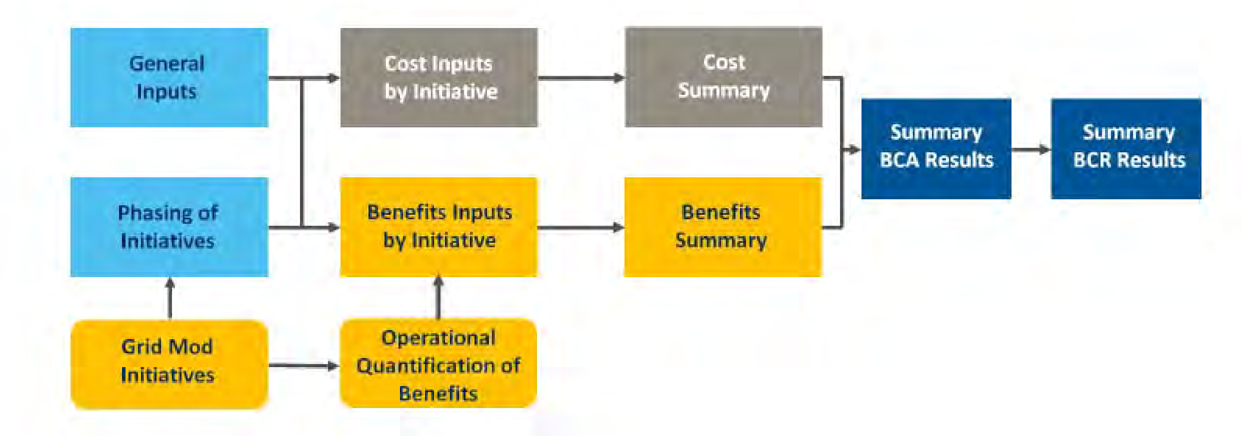


Note that in Figure 59, green boxes indicate variables that can change over time; for example, initiatives could be added or deleted. Blue boxes indicate parts of the framework that remain constant over time.

Building upon this conceptual structure, the spreadsheet structure for Consumers Energy's BCA Framework is depicted in Figure 60 below. The BCA Framework spreadsheet is organized in a bottom-up manner so that the detailed operational results (under the base/status quo scenario) and projections (under the Grid Modernization scenario) for each Grid Modernization initiative can define the incremental value which becomes the basis for the quantification and monetization of benefits.

FIGURE 60

GENERAL STRUCTURE OF BCA FRAMEWORK



a) Definition of Cost Categories

The nature of the costs associated with a utility's grid modernization investments can be grouped into the following categories:

- *Incremental Utility Capital Costs:* capital expenditures for generation plants, T&D system equipment, metering and monitoring devices, and buildings and other utility property that can be converted through accounting rules and utility-specific computational procedures into a stream of annualized capital-related expense items such as property and income taxes, depreciation (return of capital), interest on debt, and return on equity investment (i.e., the utility's revenue requirement);
- *Incremental Utility O&M Costs:* expenses for the routine costs of doing business within a specified period. Utility operating costs include fuel costs, employee payroll expenses, and O&M expenses. All expenses can be assumed to be incurred during the current period; they would appear as current-year expenses on the utility's income statement and are included in the annual revenue requirement;
- *Incremental Ancillary Services Costs:* these costs occur when DERs cause additional ancillary service costs on the utility's system (e.g., spinning reserves, and frequency regulation);
- *Equipment and Other Direct Customer-Related Costs:* these costs occur when the end-use customer decides to make long-lived purchases such as EWR devices and investments such as storage and DER (e.g., a rooftop photovoltaic ("PV") system). Some costs, such as EWR and PV, reduce the customer's electricity costs; others may improve the quality of service in terms of improved reliability or resiliency;
- *Environmental Costs:* these costs occur when generation resource decisions cause additional environmental impacts (e.g., an increased level of GHG emissions); and

- *Other Costs:* to accommodate any other costs incurred by the utility, its customers or society as part of the grid modernization planning, design, and deployment processes.

b) Cost and Benefit Categorization

FIGURE 61

BROAD CATEGORIES OF COSTS AND BENEFITS

For purposes of this BCA Framework, the benefits associated with grid modernization activities are categorized into the following three broad groupings: (1) the Utility-Cost Function; (2) the Customer Perspective; and (3) the Societal Perspective. Figure 61 above shows these three groupings with general descriptions of the types of benefits that relate to the incremental value created for the utility, its customers and society through the utility's grid modernization initiatives.

These three benefit groupings can be further defined and explained in terms of the expected impacts on the utility and energy market as shown in Figure 62 below.

FIGURE 62

BENEFITS CATEGORIZATION AND DEFINING CHARACTERISTICS

Category	Defining Characteristics	Utility/Market Impacts
Utility Operations	People and how they do their jobs; non-fuel O&M; non-production assets; safety	• Change in Asset Costs - $ [Acceleration, Deferral, Δ Expected Life] • Change in O&M Expenses - $ [Δ Labor, Δ Duty Cycles] • Change in Energy Costs - $/kWh [Δ Fuel, Δ Variable O&M] • Change in Market Purchases [Δ Energy, Δ Capacity, Δ Ancillary Services]
System Operations	The power system and its efficiency; losses; combustion; dispatch optimization emissions	
Utility Assets	Production assets required – GT&D	

Reliability/Power Quality	Frequency and duration of customer interruptions; harmonics; sags/swells, voltage violations	• Change in Other Customer Costs [Value of Reliability (VoLL), Power Quality] • Temporary housing and long-term damage costs • Cost of program-related devices (in-home displays, programmable thermostats)
Direct Customer Costs/Benefits	Equipment and other direct customer costs	
Environmental	Externalized	• Change in Societal Costs/Benefits [Emissions, Economic Impacts] • Long-term costs for public service activities
Other Costs/Benefits	Externalized	

For purposes of developing the Company's BCA Framework, the contents of Figure 62 were expanded to reflect the full range of benefit types across three categories: (1) Utility-Cost Function; (2) Customer Perspective; and (3) Societal Perspective. Figure 63 below presents each of the benefit categories included in the BCA Framework model.

FIGURE 63

BENEFIT CATEGORIES IN BCA FRAMEWORK MODEL

Benefit Category	Description/Example
Utility-Cost Function	
Reduced/Avoided Capital Costs	Avoided distribution upgrade investment
Reduced/Avoided O&M Costs	Improve the operation and performance of utility assets which can result in O&M savings
Reduced/Avoided Generation Capacity Costs	Deferral of new generation facilities and wholesale power purchases
Reduced/Avoided Energy Costs	Energy efficiency gains through the impacts of VVO and CVR programs
Reduced/Avoided Ancillary Services Costs	VVO and CVR impacts, DER support
Reduced/Avoided T&D Losses	VVO and CVR impacts
Avoided Restoration Costs	Reduced costs of restoration, equipment repair and equipment replacement, avoided truck rolls
Increased Safety	Qualitative benefits treatment
Increased DER Integration	Improvements in operating efficiencies resulting in reduced O&M costs

Benefit Category	Description/Example
Other Benefits	To be determined based on the specifics of each grid modernization initiative.
Customer Perspective	
Avoided Outage Costs	Value of Lost Load ("VoLL") estimates from the ICE Calculator applied to reduction in CMI or other improvements in reliability metric (SAIDI, CAIDI, SAIFI)
Increased DER Integration	Improvements in operating efficiencies resulting in reduced costs
Increased Power Quality	Improvements in power quality will reduce heat, vibration, and noise in ac motors, resulting in reduced energy expenses, improved machine performance, reliability, and longer life expectancy
Increased Customer Satisfaction	Customer satisfaction metric (e.g., J.D. Power) or qualitative benefits treatment.
Increased Customer Flexibility and Choice	Customer survey results or qualitative benefits treatment
Other Benefits	To be determined based on the specifics of each grid modernization initiative
Societal Perspective	
Avoided Outage Costs	Increased public safety, avoidance of damage to private property and the environment (ecosystem benefits), avoidance of economic disruption and impacts on critical facilities due to long-duration outages
Environmental Benefits	• GHG, SO_2, NO_x and particulate matter reductions. • Impacts on water consumption and related wastewater treatment • Land Use
Economic Development Benefits	Benefits created by the increased level of labor and materials required by the utility to construct and deploy each grid modernization initiative
Other Benefits	To be determined based on the specifics of each grid modernization initiative.

Benefit Category	Description/Example
	Examples: • Public Health - Impacts on public health; includes health impacts that are not included in participant impacts or environmental impacts, and includes benefits in terms of reduced healthcare costs • Energy Security - Reduced reliance on fuel imports from outside the jurisdiction, state, region, or country

ii. Initiative Benefit Estimation Methodology

The cost and benefit figures used in the model are tied to a circuit archetype where applicable. These archetypes represent how the cost and/or benefit of deployment of an initiative may vary given different field conditions and customer densities across the state. Including an archetype breakdown in the calculations enables the Company to target customer types with the greatest benefit, and to ensure an optimal mix of investment across archetypes.

When calculating benefits for an initiative, it is important to carefully consider both the intrinsic benefits of that initiative as well as interdependent benefits related to other initiatives. Different initiatives are at different levels of maturity regarding the Company's ability to fully enumerate all benefits, but for each initiative project stakeholders and subject matter experts are consulted to first ascertain what avenues of benefit are provided by the initiative, and then dive into methods of how to estimate and collect data.

For example, the ATR deployment initiative is a mature program with well-understood reliability benefits. By compiling outage data over a sample size of several years of successful operations, the Company developed a model which reflects the benefit to various circuit archetypes given the input from those actual results. The model was compared to actual results to validate its ability to forecast future benefits. With the model in place, the Company can extrapolate, for given levels of spending over given circuit archetypes, the expected system reliability benefit as compared to other initiatives. As the Company acquires more data for this and other initiatives, its models will improve.

Additional considerations must be made for initiatives with overlapping benefit. For example, the benefit for reducing outage duration due to fault location can be provided by several initiatives: DSCADA, ATRs, and Line Sensors. All combinations of those three deployments on a circuit yield different relative effectiveness for fault location benefit; but they are not additive. For illustrative purposes, suppose that DSCADA alone might provide a benefit of \$3, ATRs \$5, and Line Sensors \$10. But ATRs and Line Sensors together may only be \$12, and all 3 together may only be \$14. Therefore, data is needed to account for the relative combinations of initiatives for which there is overlapping benefit, in order to prevent potential double-counting of benefits.

a) Recognition and Treatment of Qualitative Benefits

Many important benefits associated with Grid Modernization initiatives cannot be quantified, but these benefits should be recognized in the utility's BCA and, in some cases, can be reflected using a variety of valuation methods.

FIGURE 64 below provides examples of qualitative benefits that other electric utilities in the U.S. have used in their BCAs.

FIGURE 64

EXAMPLES OF QUALITATIVE BENEFITS

Benefit Category (*Examples*)	Description
Safety, Security and Compliance	Improvements in safety for both utility employees and customers, protecting the system from cybersecurity attacks, compliance with best practice facilities regulations and standards.
Physical Facilities Risk	Reduce the risk of old/aging equipment failures (asset management benefits)
Resilient Service to Critical Services	Avoidance of sustained outages to large medical facilities, public safety agencies, state and local governments, water treatment, telecommunications and homeland security.
Benefits Not Captured in VoLL Factors	Avoidance of public safety costs, long-term costs of public service activities, temporary housing costs, long-term customer costs, increased economic harm (local and out-of-area).
Enhanced Customer Experience	Customer choice, engagement, comfort and satisfaction.

Various methods have been considered for valuing qualitative benefits. Two numerical methods have been most often used: a point system and a percentage adder. The point system method captures the relative importance of a benefit for each initiative (e.g., 0 = no benefits; 1 = low benefits; 2 = moderate benefits; and 3 = high benefits). This method enables the utility to recognize the added importance of a specific grid modernization initiative by including additional benefits in the initiative's total value stream. The percentage adder method includes an increase to certain benefits that are quantifiable (e.g., a 10% adder) to recognize the existence of the additional benefits even though they cannot be quantified. Both methods are currently used in the Company's analysis, but specific methods for valuing qualitative benefits will be refined as the Company gains additional performance data as initiatives are rolled out.

iii. <u>Utilizing the BCA Framework Spreadsheet</u>

The BCA Framework Spreadsheet is depicted in Figure 65 below. The BCA Framework Spreadsheet utilizes yellow and green shading to illustrate the relationship between various initiatives and sub-initiatives and their respective benefit categories. Formatting in this manner captures the interdependencies of initiatives and avoids double-counting benefits to arrive at an accurate Benefit-to-Cost Ratio ("BCR").

Green shading indicates that a benefit is directly produced by the grid modernization initiative or sub-initiative while yellow indicates an indirect benefit that is enabled and produced externally through that initiative. Benefits that can be quantified and monetized contain either a dollar value equal to the Net Present Value ("NPV") of the realized stream of benefits or a dollar value equal to the nominal sum of the realized stream of benefits.

Those benefits that cannot be treated in that manner will show a bullet in the cell indicating recognition and treatment of the added value as a qualitative benefit. Benefits at the sub-initiative level are ultimately summed up at the initiative level, although in some cases values are calculated at the initiative level and allocated to sub-initiatives due to the interrelated nature of certain initiatives and their supporting activities. Finally, the BCA Framework can present the quantified and monetized benefits under two system reliability options – with and without MEDs.

FIGURE 65

GENERAL LAYOUT OF BENEFITS PORTION OF BCA FRAMEWORK SPREADSHEET - ILLUSTRATIVE

Benefits Summary						Utility Cost Function								
						Reduced/ Avoided Capital Costs	Reduced/ Avoided O&M Costs	Reduced/ Avoided Generation Capacity Costs	Reduced/ Avoided Energy Costs	Reduced/ Avoided Ancillary Services Costs	Reduced/ Avoided T&D Losses	Avoided Restoration Costs	Improved Safety	Increased DER Integration
Sub-Programs	No.	Area (Short Hand)	Initiative / Sub-Intiative	Impact (requires statement involving concrete	Driver of the Impact	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category
	5	Sub Mod	Substation Modernization				•					•	•	•
	6	Mod	Distribution Circuit Modernization	(1) Automatic rerouting of power flows around an outage and enhanced restoration capabilities. (2) Reduction in the number of trips and the length of trips to investigate outages. …	(1) Ability to open and close substation devices remotely through DSCADA. (2) Ability to reroute power flows through FLISR and ATR Loops and monitor power flow conditions through …		$21,185,583	$69,999,106	$4,631,000	$5,061,494	Included as part of the reduced / avoided energy cost category	$1,212,160	•	•
	7	Cyber	Distribution Device OT Cyber Security Management				•						•	
	8	Manage	Manager of Managers			•	•					•	•	
	9	GSO	Grid System Orchestrator Business Model					•	•	•	•	•		•
	10	GSO	Grid Service Platform					•	•	•	•	•		•
	11	DER	Accelerate DER Interconnection Process			•							•	•

This summary matrix, in conjunction with supporting data tables, enables direct comparisons on the quantitative and qualitative impact of various initiatives, and the interdependencies between them.

a) Illustrative Example of the Benefit Quantification Process

This section applies the concepts discussed in the previous sections to illustrate how the benefits of a specific Grid Modernization initiative can be quantified and monetized, noting that the Company will continue working to refine its understanding of the nature and level of operational benefits enabled by the various initiatives. These illustrations are primarily designed to facilitate an understanding of the computational process and not to provide a precise determination of the level of benefits expected from the initiative.

The Distribution Circuit Modernization sub-initiative was chosen to illustrate the quantification of benefits in the BCA Framework Spreadsheet because of the work already conducted, or in progress, by Consumers Energy to determine the operational benefits associated with the specific programs that comprise this sub-initiative. This sub-initiative includes the following components:

- DSCADA – Fault Analysis;
- DSCADA – Remote Operation of Substation Reclosers;
- ATR Loops;
- Line Sensors;
- FLISR;
- VVO; and
- CVR.

For many of these components, the Company goes through a process of first estimating benefits and then measuring benefits as the component is deployed. For example, before the Company began deploying CVR, it made certain assumptions regarding expected savings, and then as CVR was deployed the Company tested it to measure the actual benefits produced. In any case, as benefits are better understood, annual operational benefits can be monetized based on the specific benefit value(s) that are determined for each operational program. For example, the capacity (MW) and energy (MWh) levels avoided (or saved) from the implementation of Consumers Energy's VVO and CVR programs are monetized by applying avoided unit capacity and energy cost values, respectively, to the reduced MW and MWh amounts. Similarly, to the extent a grid modernization initiative reduces the SAIDI metric (i.e., a reduced level of CMI) for Consumers Energy, its customers will value this reduced outage time as captured in the VoLL factors which are included as a benefit input in the BCA Framework Spreadsheet.

Figure 66 below illustrates the two-step process which consists of: (1) the quantification of the operational benefits of the initiative, sub-initiative, or program; and (2) the monetization of the quantified operational benefits. This same structure is used for each of the other initiatives, sub-initiatives or programs included in the Roadmap.

FIGURE 66

STRUCTURE OF BENEFITS QUANTIFICATION AND MONETIZATION PROCESS

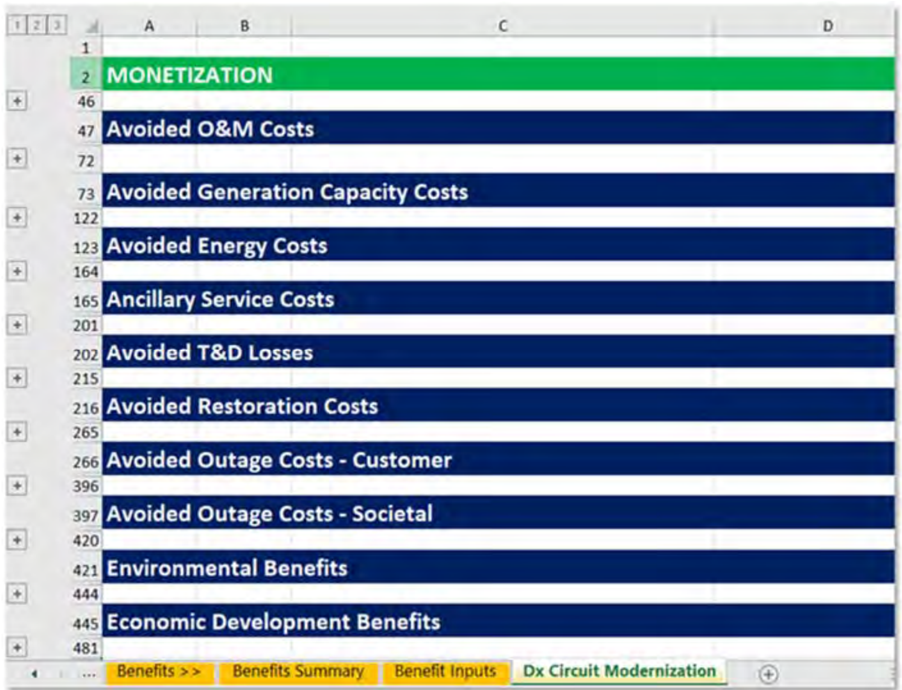


Figure 67 below provides the quantification of benefits for the Distribution Circuit Modernization sub-initiative for 2021 and for the next 10 years.

FIGURE 67

QUANTIFICATION OF BENEFITS BY CATEGORY FOR DISTRIBUTION CIRCUIT MODERNIZATION

Benefits Category	**Annual Benefits (2021)**	**Total Benefits (2021-2030)**
Utility-Cost Function		
Reduced/Avoided O&M Costs	$613,200	$12,625,636
Reduced/Avoided Generation Capacity Costs	$2,275,805	$47,830,082
Reduced/Avoided Energy Costs	$149,320	$3,139,585
Reduced/Avoided Ancillary Service Costs	$93,943	$2.696,421
Avoided Restoration Costs	$51,986	$784,486
Customer Perspective		
Avoided Outage Costs	$35,106,846	$446,443,683
Societal Perspective		
Environmental Benefits	$152,931	$4,389,522
Total	**$38,350,088**	**$530,545,051**

While the benefits in Figure 67 only include those benefits which can be quantified, there are several other qualitative benefits associated with the Distribution Circuit Modernization sub-initiative for which to account. These analyses and benefit values will continue to be refined by the Company going forward.

iv. Future BCA Development

This BCA framework is still in its early stages, and the Company will continue to collect additional data to refine its analyses. Acquiring additional data will involve getting high-level estimates based on results from industry peers and large assumptions on the impact certain initiatives provide. As initiatives are deployed, a stream of actual results will improve modeling so that it better reflects how initiatives provide benefits.

Over time, the Company will also be able to better model the ways in which initiatives support each other, through their interdependencies, to better understand the combined benefits of the entire Roadmap, rather than just the sum of the parts.

V. IRP Alignment and Integrated Planning

A. Introduction

Historically, utilities have conducted distribution planning largely separate from their electric supply planning, which is often done through an IRP process. This functional separation made sense in a world typified by a hub-and-spoke utility model, in which electricity is produced by large centralized generators which then flows in one direction across the transmission and distribution systems to end users.

That model is changing, however. As discussed elsewhere in this report, particularly in the section discussing the FES, the utility model is shifting to one that involves more decentralization. Utilities are shifting their electric supply portfolios away from large centralized generation and toward a variety of DERs – EWR and DR, a variety of distributed generation (“DG”) options, storage, and other solutions. Some of these new electric supply options will still be connected to the transmission system; for example, a 150 MW solar farm in the Company’s service territory would interconnect to the Midcontinent Independent System Operator, Inc. (“MISO”)-operated transmission system due to its size. Many of these electric supply options can be located on the distribution system, though, and an increasing share of them likely will be on the distribution system in the future. Furthermore, penetration of electric vehicles (“EV”) is likely to grow in the coming years, and there is increasing interest by many parties in electrification of various other systems that are currently powered by natural gas. As all of these things happen, the nature of the distribution system will change from the traditional one-way model to something more dynamic.

Much of this shift will be accommodated by the increased use of new technologies, which is a driving factor behind the Company’s Grid Modernization Roadmap. But much of it will also require a new approach to planning, one in which distribution and electric supply planning are evaluated all together in a single streamlined process, a concept referred to as “integrated planning.” In integrated planning, the solution to a particular grid issue may be pure distribution (e.g., a new substation), pure electric supply (e.g. a new solar installation on a circuit) or a mix of multiple solutions.

The Company is not yet in a position to do true future-state integrated planning. However, the Company has been an active participant in MI Power Grid workshops exploring what this future state will look like, and the Company looks forward to deepening its integrated planning in the next few years. And even though the Company is not yet conducting fully integrated planning, it is making clear progress toward doing so. The Grid Modernization Roadmap provides platforms for the distribution system to reliably accommodate electric supply solutions as they are selected. The Company’s hosting capacity analysis (“HCA”) process, discussed later in this report, is creating a tool to show where DERs can be added to the distribution system. As the Company explores NWS, also discussed later in this report, it is bringing together distribution planners with various customer program groups to identify ways of solving distribution and electric supply issues at the same time.

Beyond these efforts, the Company has made a conscious choice to submit this EDIIP at the same time that its 2021 IRP is filed. By doing this, the MPSC and other stakeholders will have a clear opportunity to consider the Company's distribution plan and electric supply plan side-by-side at the same time. This timing also has meant that the Company developed the two filings in parallel with one another – because much of both plans has been developed under a single Electric Planning organization, key planning personnel and decision-makers within the Company have been able to continuously collaborate regarding both plans.

There are several IRP-specific issues that impact distribution planning. The following sections explain how the Company is working toward integrated planning in the areas of load forecasting and DER planning, with specific emphasis on battery storage planning, plus potential EV outcomes.

B. Load Forecasting

The Company conducts ongoing load forecasting to inform a variety of business decisions, given the need to closely match electric supply and demand and to ensure adequate electric supply capacity to meet peak requirements. Load forecasting is a critical part of the Company's IRP processing due to this need. While load forecasting is a less critical part of distribution planning in general, since many distribution projects are not tied to load, the Company's Capacity capital investment program responds, in part, to distribution load issues. Because of this, the Company works to ensure that the load forecasts used in the Capacity program for electric distribution is as closely aligned as possible with the corporate load forecasting process used in the IRP. By doing so, the Company ensures that both its IRP and its electric distribution plan are using a single source of truth regarding expected load growth.

Because the Company's HVD and LVD systems, plus the Company's LVD substations, have unique attributes and because the Company's Capacity projects differ in type across the different asset groups, the Company uses different means of aligning load forecasts for each Capacity sub-program, as described below.

<u>Corporate Load Forecasting</u>

The Company develops two major corporate load forecasts each year, which inform the Company's IRP as well as other regulatory proceedings, like electric rate cases and PSCR cases. The Company produces a fall forecast every year in October and November, which usually focuses on a one- to two-year horizon. Each April and May, the Company produces its spring forecast, which usually focuses on a five-year horizon.

Corporate load forecasts consist of the following steps:

1. The Company compiles historical data including load, weather, and economic indicators;
2. The Company reviews the data for any erroneous issues;

3. The Company runs regression models to create future projections; and
4. Load adjustments, such as direct load control and time-of-use programs, are applied to the projections to create a net forecast.

Any historical load modifying resources ("LMRs") are implicitly included in the historical data in Step 1 and would appear as reduced historical load. As noted in Step 4, projected future reductions of load are applied to the projections to create a net forecast.

In the Company's 2021 IRP, the corporate load forecast includes certain new distribution-related components that did not exist in the 2018 IRP. In particular, the corporate load forecast accounts for existing and planned CVR on the distribution system, which did not exist when the 2018 IRP was developed. Also new in the 2021 IRP is the impact of residential Summer Time-of-Use rates on peak demands. Additionally, the corporate load forecast includes an increase in electric vehicle penetration through 2040; in the 2018 IRP, electric vehicle penetration was considered too small to model in the corporate load forecast.

HVD Lines and Substations

The Company's HVD Lines and Substations Capacity sub-program is the primary investment area in which load forecasting can affect investments in HVD lines and substations. Each year, the Company compiles summer peak loads for each of its 20 HVD regions. For each HVD region, the Company uses recent historical regional peaks to create a forward-looking trend line. Each regional trend line, when projected forward, is adjusted on a *pro rata* basis so that the forecasted total system load (i.e. the sum of forecasts of each of the 20 HVD regions) is aligned with the corporate load forecast for a given period. Because this forecasting is done based on summer peak load, it is aligned with the Company's concurrent fall corporate load forecast, although changes to the HVD forecasts can be make out-of-cycle if there is a dramatic change in the spring corporate load forecast.

Because these regional HVD load forecasts are normalized to the corporate load forecast, they also implicitly include any historical LMRs. Future reductions of load, including direct load control and other programs, are allocated *pro rata* across all HVD regions in the same manner as the general trend lines discussed above.

The Company uses the regional HVD load growth forecasts to identify any load growth-driven project needs on a one-, three-, and six-year basis.

- On a one-year horizon, the forecasts serve primarily as a check on the Company existing plan;
- The three-year horizon forms the basis for most load-driven projects on the HVD system, given typical project timelines; for example, peak loads from 2019 would yield forecasts that primarily identify 2021 and 2022 projects; and
- The six-year horizon provides an expanded future look at potential needs but is not primarily used to identify projects.

LVD Substations

The Company's LVD Substations Capacity sub-program is the primary investment area that accommodates load growth on LVD substations. This sub-program generally does not rely on trend-based load growth forecasts to identify projects, but instead responds primarily to observed exceedances of loading criteria at the local substation level, and due to this local nature is not explicitly tied to the system-wide corporate load forecast.

Each year, the Company compiles summer peak loads for all LVD substations, with the data available by October. If load criteria were exceeded at a substation, then the Company develops and schedules a project to remediate the issue, and if urgent a project can be completed by the following June in advance of the next summer. If no load criteria were actually exceeded, but one or more criteria are loaded at between 90% and 100%, then the Company flags that substation to potentially address in its long-term plan (see the later section in this report on the LVD Substations Capacity sub-program for additional details).

The Company's long-term plan for LVD substations considers recent growth trends on specific LVD substations as well as input from the Company's other planning and customer-oriented groups (i.e. System Engineers, System Owners, CEM Project Coordinators, economic development, account managers, etc.) on expected local load growth. In particular, the Company works to distinguish whether recent load growth is due to a single new or expanding customer or if it is due to broader load growth in the area. In the former case, recent load growth on a particular substation is likely to be a single step-change event, and load would be unlikely to continue growing at dramatic levels. In the latter case, recent load growth is more likely to be continuous and sustained. Making this distinction informs the Company on what kind of project is most appropriate, and when it would be needed.

<u>LVD Lines</u>

The Company's LVD Lines Capacity sub-program is the primary investment area addressing load growth on LVD lines in which load forecasting can affect investments. The Company compiles monthly load peaks for each LVD circuit and uses this data to project trend lines forward. These projections inform the Company's annual planning cycle, which develops projects two years in advance. For example, in January 2020 the Company viewed peak load data and corresponding projections from 2015 through 2019 to begin planning projects for 2022. In the fourth quarter of 2020 the Company reviewed these projects against line sensor data from the summer where available, allowing for projects to be removed if they were no longer needed or prioritized earlier in the plan.

Historically, the Company assumed annual load growth of 2% when identifying LVD Lines Capacity projects. Today, if historical circuit data is not available or does not support a projection of load growth on a given circuit, then the Company holds circuit load growth flat in its projections, in line with the system-wide corporate load forecast. In this sense, LVD lines are similar to LVD substations, in that capacity projects are developed only when local data indicates local load growth.

C. DER Planning

The MI Power Grid workgroup on distribution planning defined a DER as "a source of electric power and its associated facilities that is a connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system." (August 20, 2020 MPSC Order in Case No. U-20147, pg. 11.) The Company's 2021 IRP considers DR and EWR as electric supply options, but these do not generate or store power, and therefore are not part of this definition of

DER. The 2021 IRP also considers battery storage resources connected to the distribution system, as discussed in the next section of this report.

In the 2021 IRP, distributed solar generation is the major DER considered as an electric supply option. The IRP modeling evaluated two solar prototypes. One prototype was solar installations greater than 50 MW, or utility-scale solar, and the other prototype was solar installations in between 1 MW and 20 MW. Of the two prototypes, only the second one would be connected to the distribution system (either HVD or LVD, depending on the size of a particular installation). Utility-scale solar installations greater than 50 MW are, due to their size, interconnected to the transmission system through MISO's generator interconnection process and therefore fall outside the scope of distribution planning.

The 2021 IRP also accounts for customer-owned behind-the-meter solar generation. In the IRP, this is treated simply as reduced load on the system (in the IRP base case, this behind-the-meter generation makes up a very small amount of the system total, but the Advanced Technologies scenario, discussed below, modeled a larger amount). To the extent that this behind-the-meter solar generation is counted as reduced load, it is captured in the corporate load forecast, as discussed in the prior section of this report.

Data inputs in the 2021 IRP indicate that utility-scale solar, connected to the transmission system, is cheaper on a per-MW basis than the smaller solar prototype connected to the distribution system. Ultimately, though, the IRP only specifies a total number of MW to be provided by solar generation, without regard to specific locations or sizes of individual installations – in other words, while the model selects solar generation based on the costs of transmission-connected solar, it does not prohibit distribution-connected solar from being built. Because the Company uses competitive solicitation for new solar generation associated with IRP planning, it is possible that the Company could receive successful bids for distribution-connected solar generation.

The IRP also includes an Advanced Technology scenario in which the capital costs of distribution-connected solar are reduced by 50% and the capital costs of transmission-connected solar are reduced by 35%. If that were the reality in the future, distribution-connected solar would become more economically competitive, and would consequentially see further penetration onto the grid. The Advanced Technology scenario also forecasts further growth of behind-the-meter solar generation in the future.

In a situation that did involve a large increase in the need to interconnect solar generation to the distribution system, the Company will be prepared to accommodate this in its distribution planning. The Company is developing its HCA capabilities, as discussed later in this report. As those HCA capabilities mature, the Company will be able to identify sites on the distribution system that are already well-suited for DER interconnections. The Company's planned investments in a DERMS will also position it to manage a higher penetration of distributed solar generation and other DERs; as discussed in the section of this report on the Grid Modernization capital sub-program, the Company is making initial investments in DERMS in 2021 to prepare for a future with higher DER penetration.

The Company expects to further integrate DER planning between distribution planning and electric supply planning in response to MPSC guidance following the MI Power Grid Advanced Planning workgroup process.

D. Battery Storage

Because traditional IRP modeling is concerned primarily with optimizing the most economic electric supply portfolio, the Company's IRP modeling formally analyzes batteries as electric supply assets. In the IRP modeling, the Company considers four different battery prototypes representing different value streams that batteries can create. While all four prototypes provide energy and capacity, one prototype is a battery that *only* provides energy and capacity. A second prototype provides ancillary services to the grid in addition to energy and capacity. While these prototypes could provide theoretical distribution benefits, they are not modeled as doing so, and if built they would serve a primarily economic electric supply purpose.

The third battery prototype considered in the IRP is a solar-plus-storage resource, in which the primary purpose of the battery is to support solar generation. The Company has already developed one such installation with its Cadillac Solar Battery project, discussed later in the section of this report on the Grid Storage capital sub-program. With this prototype, the battery charges from the adjacent solar resource up to 75% of the time, and not from the grid more than 25% of the time, so the direct benefits to the distribution system are limited; the battery would not be considered a solution to a distribution issue.

The fourth battery prototype considered is the distribution asset upgrade deferral ("DAUD") battery. DAUD batteries are significantly smaller than the other prototypes, at 2 MW per unit, meaning they would be able to interconnect to the distribution (as opposed to transmission) system. In the IRP, these batteries are modeled as dispatchable electric supply resources and are therefore evaluated economically against other types of resources. But, in a form of integrated planning, the ability of DAUD batteries to defer the need for a capacity project on the distribution system is built into the economic analysis; the batteries are explicitly evaluated as both an electric supply solution and a distribution solution, and are thus a type of NWS. When the IRP model evaluates DAUD batteries, it models their electric supply value, but also considers the value created through deferral of a distribution asset.

To conduct this dual evaluation, the Company determined the value created by deferring a distribution upgrade. The Company identified 23 LVD substations a) with loadings of 80% of capacity or more; that b) were projected to become overloaded between 2020 and 2040; and c) would be relatively expensive to upgrade, usually involving either a bank replacement or a full rebuild. For each of these substations, the Company determined the upgrade cost deferred by the battery in the following way:

1. The approximate load on the LVD circuit(s) after a deferral period of 15 years was calculated using the load growth rate. The difference in load over that 15-year period (the load growth) was used to determine the power needed in MVA. A power factor of 1 is assumed, such that 1 MVA of increased load is satisfied by 1 MW of battery power capacity;
2. The estimated cost of upgrade, in the dollars of the year of the upgrade, was determined by taking the year of the proposed upgrade, the estimated cost of the upgrade in 2020 dollars, and assuming a yearly inflation rate of 3%. The present value of this upgrade is calculated in 2020 dollars assuming a discount rate of 7%; and
3. The difference between the estimated cost of the upgrade in 2020 dollars and the present value of the estimated cost in 2020 dollars is the cost avoided in 2020 dollars by the deferral. The avoided cost per battery kW is then calculated for each of these substations.

Through this process, the Company determined that DAUD batteries would yield a one-time cost avoidance of $194/kW of battery. This benefit was added to the overall value stack of the batteries and counted alongside other costs and benefits of these batteries in the IRP model. To make a very simplified illustrative example, if the capital costs of a DAUD battery were $2 million, but the battery included avoided distribution upgrade costs of $300,000, then the battery would be modeled as though it cost $1.7 million.

The Company's 2021 IRP does not select any batteries for the EDIIP timeframe of 2021 through 2025, largely because a capacity need is not identified for selection of resources on top of those already approved through 2025 in the 2018 IRP.

However, this does not mean that DAUD batteries are not part of the Company's future. The Company's IRP models many different scenarios and sensitivities, some of which result in earlier additions of storage. The Advanced Technology scenario, for example, forecasts storage capital costs falling at a faster rate than the Business as Usual scenario, which could drive more deployments of DAUD batteries. For any DAUD batteries that ultimately are selected through an IRP for future timeframes, the Company's distribution planners would be responsible for identifying locations to install the batteries, since the IRP model itself is not location-specific. To do this, planners would identify substations with relatively high loadings that are projected to become overloaded in a future year, in a similar manner to the process described above for calculating the avoided cost figure. Because the IRP selects for resource needs years ahead of time, there is enough time to identify locations for these batteries.

By the time that the Company expects to deploy IRP-selected DAUD batteries on its system, the Company will also have the benefit of additional lessons learned through the projects being developed in the Grid Storage capital sub-program, discussed later in this report. That sub-program includes an asset deferral battery being completed in 2021.

It is important to emphasize that the primary purpose of IRP modeling is to identify an optimal economic portfolio of electric supply resources, meaning that DAUD batteries selected through an IRP would be part of an optimal electric supply mix developed based on the Company's Triple Bottom Line, and would then also provide a defined distribution grid benefit. On the other hand, future batteries may be developed through the Company's Grid Storage capital sub-program based primarily on the distribution grid benefits provided, and those batteries would also provide an electric supply benefit. In short, there may be different primary reasons why a battery is proposed, but batteries can still provide multiple benefits. In any case where the Company develops batteries, it will work to identify the most optimal location where grid benefits can be maximized, particularly if it will address loading issues.

E. Electric Vehicles

In the Company's 2021 IRP, the base case assumes continued growth in EV penetration from a relatively low base. Over the five-year investment period covered by this EDIIP, this EV growth is not expected to drive a need for major distribution grid investments; while installing a charging station requires about $40,000 in "make-ready" work, large-scale upgrades will not be needed in this timeframe. The Company is already in the first phase of deploying electric charging stations for its PowerMIDrive program, based on an analysis of optimal locations from Michigan State University. These charging stations are largely being located near the edges of cities with easy access to highways, and these locations have sufficient distribution capacity to accommodate that load. Later phases of charging station deployment could take place in downtown areas, as noted earlier in the section of this report on the Metro System Strategy, but this is not expected in the near term. The PowerMIDrive program, in general, is already providing the Company with insights regarding customer charging patterns and potential challenges to the grid posed by EV adoption; the Company's PowerMIDrive management is in regular contact with LVD planners to monitor grid impacts, and to date no reliability issues have occurred.

Much EV charging will likely take place at customers' homes. While an individual customer charging at home has limited distribution grid impact, especially since approximately 90% of such charging has taken place during off-peak hours, increasing EV penetration could eventually create grid issues; particularly if a lot of EV charging is concentrated in some neighborhoods more than others. While this is also not expected to drive a need for major investments over the next five years, it may become a distribution planning consideration further in the future.

The IRP base case will assume that EV growth will accelerate in the second half of the 2020's and into the 2030's, coinciding with announced shifts toward EV production from major automakers. Furthermore, the IRP's Advanced Technology scenario will assume an even larger and faster EV penetration. In short, the Company's distribution planning will need to increasingly account for EVs over the longer term beyond the five-year period covered in this EDIIP. The Company will increasingly need to identify neighborhood EV clusters in advance to identify potential overloads and maintain reliability. If time-of-use ("TOU") rates are not adopted by such EV customers to optimize charging, then the Company may also need to develop active measures to control or influence the timing of when customers charge their vehicles to keep the grid properly balanced. However, to date TOU rates have been very effective incenting off-peak charging. The MI Power Grid workgroup on New Technologies and Business Models in 2021 has been considering these issues, and the Company expects continued work and collaboration on this topic as further integrated planning approaches are developed.

Beyond electrification of cars and light trucks, significant electrification of fleet vehicles could have a major impact on the Company's overall electric load profile. Electric fleet vehicles would likely be charged at central locations like shipping warehouses or bus depots, rather than at widely dispersed locations like customer homes. Electric fleet vehicles are also anticipated to have larger battery capacity, and thus likely larger load profiles while charging than a residential EV. Consequently, the impact to distribution planning will be different than the impacts due to cars and light trucks; the Company would need to plan for increased load at single concentrated points rather than increased load across an entire neighborhood.

VI. Emerging Topics

A. Non-Wires Solutions

i. Background and Context; Why Non-Wires Solutions?

In recent years, many parties have expressed interest in expanding the use of NWS, also known as non-wires alternatives ("NWA"), in the distribution planning portfolios of utilities. (The MPSC's August 20, 2020 Order in Case No. U-20147 defines non-wires alternatives as "a[n] electricity grid investment or project that uses distribution solutions such as DERs, energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.") Groups representing different sets of customers, for example, are interested in using NWS as an approach to identify lower-cost solutions to distribution issues. Environmental groups are interested in the potential of NWS, given the technologies often used, to reduce carbon emissions by reducing utility generation requirements, among other potential benefits. Regulators are concerned with ensuring that utilities have the proper incentives to explore new approaches to distribution planning, while continuing to provide reliable service at a just and reasonable cost. Utilities, for their part, must adapt to changing customer preferences and adopt new approaches to distribution and supply planning, when those new approaches can provide the ability to meet the utility's obligation to serve customers in a reliable and cost-effective way.

While the concept of NWS, and the technologies that enable them, have existed for over 20 years, the utility industry has only begun to investigate their use on a broader scale over the past several years. Consumers Energy began exploring NWS in 2015 when the Company made an agreement with the Natural Resources Defense Council to collaboratively explore the use of EWR and DR programs to defer or avoid a capacity-driven distribution upgrade. As the Company's residential DR programs were then still in pilot stage, the Company's initial study of NWS focused on identifying sites where an NWS pilot might be suitable. The Company launched its first residential DR programs in 2016, enabling the Company to launch its first NWS pilot, based on targeted residential DR, at Swartz Creek in 2017. After the Swartz Creek pilot concluded in 2018, the Company developed a second pilot at a location north of Grand Rapids on the Four Mile substation in 2019. As noted above, many parties are interested in the Company continuing to pursue NWS, including expanding beyond capacity-driven issues and beyond EWR and DR use cases. In the near-term, the Company is beginning to expand its study of NWS to evaluate means of improving reliability and resilience (though not deferring or avoiding traditional reliability projects) and is considering additional technologies for NWS applications, such as utility scale ("US") and customer sited ("CS") storage and distributed solar generation, with the idea of considering a more robust suite of options to evaluate as solutions. The Company will pursue this study of NWS, and, pending success in its pilots and a supporting regulatory framework, will move forward with a corresponding roll-out of post-pilot NWS projects over three phases as discussed below. The Company anticipates continuing to propose and justify specific NWS pilots and projects in future regulatory proceedings, such as electric rate cases, as progress is made in these phases.

This process is contingent on the Company successfully completing pilots before scaling them up into widespread adoption as a routine part of the Company's distribution planning. The Company has, first and foremost, an obligation to operate the distribution system in a reliable manner. Fully incorporating NWS into distribution planning will require confidence, based on pilot results, that the system will continue to operate reliably when an NWS is deployed.

ii. NWS Pilot Progress since 2018

Because maintaining distribution system reliability is a paramount concern, in order to successfully integrate NWS into distribution planning, the utility must know 1) if the NWS will reliably work to solve the targeted distribution issue; and 2) if the NWS will be the least-cost solution. Therefore, fully developed NWS that can be regularly used as "off the shelf" solutions by distribution planners must have an established 1) cost; 2) deployment schedule; and 3) reliability parameters. The objective of the Company's NWS pilots since the 2018 EDIIP was filed has been to study how potential NWS technologies and programs operate in the field, in order to better answer these questions.

a) Swartz Creek Pilot

The Company's first NWS pilot, at Swartz Creek, began in October 2017 and concluded at the end of 2018. The purpose of this pilot was to test the feasibility of using targeted residential and C&I EWR and residential DR to reduce the peak load on a substation (in this case, the Swartz Creek substation) in order to defer an anticipated capacity upgrade on that substation. When the Company was developing this pilot, it anticipated that it would need to reduce load on the substation by 1.4 MW in 2018 or 1.6 MW in 2019, based on anticipated load growth. The alternative substation capacity upgrade was expected to cost $1.1 million in capital investment.

Based on these parameters, the Swartz Creek substation met the Company's selection criteria at the time:

- A distribution system upgrade was anticipated based on projected load growth;
- The expected upgrade need was at least two to three years in the future; and
- The deferrable upgrade cost was at least $1 million (a minimum deferrable upgrade cost increases the likelihood that an NWS will be a lower-cost option).

The Company invited all customers in the Swartz Creek 48473 ZIP code to participate, even if not located on the Swartz Creek substation, in order to promote community engagement in the pilot. The Company conducted outreach to educate and encourage customers to save money and energy by enrolling in EWR and DR programs. The Company used a designated "energy ambassador" to represent the Company at public events, to answer public questions, and to develop an Energy Task Force that included the Swartz Creek city manager, business owners, and the STEM director of the local schools. The energy ambassador also helped guide customers through registration. The Company also advertised the program on the radio and through billboards and mailings. At key points in the summer and fall of 2018, the Company offered targeted bonus incentives to customers on the Swartz Creek substation to further encourage participation.

Following the pilot, the Company calculated that the EWR component led to a total reduction of approximately 795 kW in the City of Swartz Creek, and approximately 363 kW on the Swartz Creek substation. At peak times during the year, reductions due to EWR and DR together were as follows:

- Peak demand day of 2018 for Swartz Creek substation: 10.4 kW;
- Peak demand hour of 2018 for the MISO system: 37.2 kW; and
- Peak MISO locational marginal price hour of 2018: 63.7 kWh in reduced usage.

Additionally, over the pilot period, C&I customers saw increased EWR load reductions when compared to the three prior 12-month periods, even though C&I DR was not a part of this effort.

Crucially, the substation's peak day took place on a Sunday immediately after the Fourth of July, and the Company was only able to call a residential DR event if there was a MISO emergency, which was not the case. Without the ability to call a DR event, the Company was not able to fully test the ability to reduce peak demand.

Ultimately, load growth on the Swartz Creek substation did not progress as rapidly as it had earlier in the decade, meaning that the substation upgrade has to date not been needed.

The Company learned several important lessons from its experience with the Swartz Creek pilot:

- Perhaps most importantly, residential customer load – and the load on substations serving predominantly residential customers – does not always peak on weekdays when DR events are most easily called;
- Offering bonus incentives clearly increases participation. During the period when incentives were offered, beginning in August 2018, the Company saw an increase in participation compared to the same period in the prior year, and month-to-month data on energy savings also indicated increases in savings at time that incentives were offered; and
- Marketing must be targeted. Direct customer contact is more effective than general broadcast advertising, particularly with C&I customers who receive assistance through Company representatives.

b) Four Mile Pilot

The Company applied the lessons learned from Swartz Creek in identifying a location for a second NWS pilot, particularly by refining the selection criteria. For the second pilot, the Company used three primary selection criteria:

- Anticipated load reduction need of 5%-20% to defer an upgrade;
- The expected upgrade needs three to five years in the future; and
- The deferrable upgrade cost between $1 million and $3 million.

Furthermore, the Company added three secondary selection criteria:

- A maximum of 40% residential load share, to allow the Company to better understand C&I EWR and DR potential;
- DSCADA availability to improve insight into peak timing; and
- Historical EWR and DR participation.

The Company evaluated several substations using these criteria, and found that the Four Mile substation northwest of Grand Rapids was an optimal location, as shown in Figure 68 below.

FIGURE 68

ASSESSMENT OF FOUR MILE SUBSTATION AGAINST SELECTION CRITERIA

Criterion	Target Range	Four Mile
Load relief needed	5%-20%	10%
Deferrable project cost	$1M-$3M	$2.5M-$3M
Expected upgrade need	3-5 years out	2023-2024
DSCADA available	Yes	Yes
Residential load share	≤40%	18%

The purpose of the Four Mile pilot is to continue studying the use of targeted EWR and DR to address distribution capacity needs, adding C&I economic DR into the resources evaluated, in order to reduce peak load by ~0.5 MW by 2023 and defer the need to build a new substation. The Company began the pilot in August 2019, and it will conclude at the end of 2021, allowing two full summers of data to be compiled and analyzed.

The Four Mile substation has more C&I customers, and a much larger share of C&I load, than the Swartz Creek substation. Industrial developments have either taken place or are expected to take place on the substation, leading to expected load growth.

Beyond refining selection criteria, the Company is applying other lessons from Swartz Creek for the Four Mile pilot, including increased incentives and targeted marketing. The Company offered C&I customers up to $1,000 for enrolling in air conditioning, refrigeration, and lighting programs. The Company benchmarked incentives for residential customers against others in the industry, and then offered higher amount to increase participation, as shown in Figure 69 below. Rather than wait until several months into the pilot as at Swartz Creek, at Four Mile the Company began the pilot by offering incentives immediately.

FIGURE 69
RESIDENTIAL BONUS INCENTIVES

Measure	Typical Incentive	NWS Total Incentive
HVAC- 14.5-14.99 SEER	$50	$100
HVAC- 15.0-15.99 SEER	$150	$300
HVAC- 16.0-16.99 SEER	$200	$400
HVAC- 17.0 - 18.99 SEER	$400	$800
HVAC- 19.0-20.99 SEER	$450	$900
HVAC- 21.0 SEER or Higher	$500	$1,000
HVAC- AC Tune-up	$50	$150
AC Peak Cycling	$25	$50
Appliance Recycling	$50	$75

Because the Company found that mass advertising was less effective at Swartz Creek compared to direct mail and email, at Four Mile the Company has focused on emails, postcards, and other mailings to customers regarding key programs, with a special emphasis on bonus incentives. The Company has also increased direct engagement with C&I customers, with the Company's Local Affairs Managers and Energy Solutions Managers meeting directly with these customers, and by working to educate key trade allies such as heating, ventilation, and air conditioning and lighting contractors to make them aware of the Company's programs.

The Four Mile pilot remains ongoing, with final results expected early in 2022. These results will further inform the Company as it moves through subsequent phases of NWS development.

While the Four Mile pilot continues, in the spring of 2021, the Company learned that new business load announced on a circuit connected to the Four Mile substation will require the Company to build a new substation even with the projected NWS savings. This new business load includes a manufacturing facility expected to be in operation later in 2021 that will add 1.5 MW of load. It also includes a commercial distribution center with a collocated EV charging center expected to be in operation in late 2022 that will add 5 MW of load. This second addition will put load on the circuit well beyond the load reduction that the Four Mile NWS pilot might reasonably achieve (as noted above, targeted peak load reduction was ~0.5

MW). The Company must begin planning for this new substation now, in mid-2021, to ensure it is in operation by late 2022.

Notwithstanding this development, the Company is continuing with the pilot to continue learning regarding, among other things, DR and EWR promotion, actual load reduction results, and cost effectiveness of those load reductions.

This situation illustrates that, even when secular *growth of existing load* is forecast far enough in advance to allow an NWS to be developed, relatively sudden *new load* can still obviate NWS efforts. While the situation at Four Mile involved new C&I load announced many months in advance, other new load can provide far less advance notice. The Company had forecast that the secular growth of existing load would cause the Four Mile substation to be overloaded in 2023-2024, as shown in Figure 68, whereas this new load is materializing in 2021-2022.

Overall, these issues emphasize the prudence of the Company's deliberate approach on NWS, as there are no shortcuts for maintaining a reliable grid. This will be discussed in the following sections.

FIGURE 70

NON-WIRES SOLUTIONS STRATEGY OVERVIEW

Background, Context, Drivers	• *Consumers Energy began exploring NWS in 2015 with an agreement with NRDC to work collaboratively on NWS. Since then, the Company initiated a pilot at Swartz Creek in 2017 before moving to a second location north of Grand Rapids, Four Mile, in 2019. Both locations studied deferring or eliminating a capacity driven infrastructure project. External parties are interested in the Company expanding beyond capacity related pilots, and the Company is beginning to study using FTM and BTM storage and solar for NWS in pursuit of greater reliability, clean energy, customer control, advanced technologies, and a modernized grid.*
Horizon and Phases	• Phase 1 (2017-2021): Initial pilots • Phase 2 (2022-2024): Additional and later-stage pilots, plus integration and initial projects • Phase 3 (2025-2027): Advanced pilots, integration, and scaled projects
Vision	• *The Company will thoughtfully work to pilot, integrate and scale NWS. It will integrate NWS analysis into the planning process, selectively choose those sites deemed eligible, grow its capabilities (processes, tools and offerings) to effectively deploy the needed NWS for each site to deliver clean, lean, and cost-effective solutions to address customer and grid needs.*

Current State	• Areas of NWS exploration: Swartz Creek pilot 2017-2018; Four Mile pilot 2019-Ongoing
	• Narrowly focused to date:
	    • Deferral of large substation capacity projects
	    • Targeted EWR and DR
	• Potential NWS technologies (being studies, but not as NWS):
	    • Utility-scale storage
	    • Customer-sited storage
	    • Other targeted customer programs (i.e. Bring Your Own Device)
	• Developing selection process (not yet operationalized as a planning tool) and analytics capabilities to inform suitability criteria
	• No incentive mechanism based on NWS performance

Strategy	*Build on past and current pilot efforts, gaining insights and developing processes and capabilities. Integrate these processes and capabilities into planning and operational processes and activities to enable scaling beyond pilots into projects. Continue growing skills through ongoing piloting of additional products in a cycle:* **Pilots** build capabilities and insights Develop new **analytical capabilities and tools** **Integrate** in planning processes **Scale up** into projects based on pilot results Evolve **regulatory framework** to support NWS growth
Framework	• Solutions – Initial pilots have focused on capacity projects using EWR and DR programs. CS and US storage will be piloted in late Phase 1, and both will carry into Phase 2 as pilots. DG and EVs will also be layered in as pilots in Phase 2. • Approaches – Pilots have been program based, but the Company may consider pricing and procurement approaches, depending on appropriate regulatory framework, based on metrics and performance tracking. • Capabilities – Suitability criteria for capacity projects being refined in Phase 1. As reliability, resilience, and other use cases are studied, suitability criteria will be developed for each to identify possible pilots/projects in those areas. For any use case, suitability criteria will indicate if a given NWS is feasible for a particular site.
Future State	*Phase 3 and beyond will see scaled project work, a continuation of new pilot activity, and deeper integration. NWS projects will be identified in an integrated planning process and selected via an integrated analysis to identify the best method to achieve the specific project goal(s).* • *The scope of NWS will continue to evolve* • *NWS operationalization will depend on pilot results and scalability*

iii. High-Level Scope and Phases

The Company initiated its first NWS pilot in 2017. Phase 1 of NWS development will run through at least 2021 on the Four Mile substation. The Company will further explore NWS with additional pilots to study innovative technologies and how to solve for issues other than capacity. If the current NWS pilot at Four Mile continues to be successful, the Company will begin further integration of NWS into its planning processes and begin developing initial post-pilot NWS projects as it moves into Phase 2 of NWS development. Phase 3 will be a continuation of those efforts with a move toward scaled NWS projects.

- Phase 1 (2017-2021): Initial pilots (targeted EWR and DR, initial battery applications);
- Phase 2 (2022-2024): Additional and later-stage pilots (expanded use cases to potentially include distributed generation, batteries, etc.), plus integration and initial projects; and
- Phase 3 (2025-2027): Advanced pilots, integration, and scaled projects.

NWS pilots in Phase 1 have largely been limited to EWR and DR, although the Company has conducted other CS and US storage pilots separately from the Swartz Creek and Four Mile pilots. Pilots in Phase 2 and Phase 3 will expand into additional technologies, use cases, and approaches. In the context of Phase 2, "integration" refers to developing processes and organizational structures internal to the Company so that every Company business unit involved in planning, deploying, or operating an NWS is working from a standard set of assumptions, business models, and operational parameters. "Scaled projects" translate the tested efficiencies in processes, selection, design, and implementation from successful "pilots" into cost effective solutions supporting NWS goals. Scaled projects would consider developed suitability criteria, screening and planning processes and would be implemented as a distribution solution. Further details regarding these phases are shown in Figure 71.

iv. NWS Vision

The Company recognizes the potential value to customers in pursuing NWS. To support this, the Company will thoughtfully work to pilot, integrate, and scale NWS with business models supported by an appropriate regulatory framework. The Company will work to integrate standardized NWS analysis into the planning process, selectively choose those sites deemed eligible, and grow its capabilities (processes, tools, and offerings) to effectively deploy NWS for each site to deliver clean, lean, and cost-effective solutions addressing customer and grid needs.

v. Current State

As illustrated above, the Company is currently in Phase 1 of NWS, meaning much of the Company's attention has been narrowly focused. The initial focus, first at the Swartz Creek substation and now at the Four Mile substation, has been deferral of large substation capacity-related infrastructure projects, particularly using targeted EWR and DR.

The Four Mile pilot is using existing Residential and C&I EWR and Residential DR programs to reduce demand on the substation, including testing C&I Economic DR within the pilot. The Company has successfully tested the ability to call localized, circuit-level DR events and plans to use the Four Mile pilot to develop and test the ability to accurately forecast these localized events. The pilot at Four Mile will continue through 2021.

In Phase 1, the Company is developing its ability to identify appropriate sites for NWS, building processes and analytical capabilities which are intended to support the development of NWS site selection tools to enable NWS operational planning. For example, the Company used lessons learned from the Swartz Creek pilot in selecting the Four Mile substation as a suitable site. In conducting the 2018-2019 analysis, the suitability criteria were enhanced, leading to selection, and expanding to Four Mile to provide new learning opportunities. The Company also further refined these processes and abilities in reviewing other potential NWS sites as part of the DR incentive framework. The Company plans to further develop its ability to identify suitable NWS sites, so that NWS can be regularly considered in the planning process as sites are recognized in a standardized manner.

The Company is beginning to broaden its focus in the latter stages of Phase 1, particularly by considering the potential NWS applications of technologies and programs that were initially conceived for other use cases. In addition to the Four Mile pilot, the Company has conducted another pilot on a different substation (Moline) to study residential CS storage. Initially focused on 50 customers on a single circuit, the Company plans to expand its investigation of CS storage to a broader range of customers in 2022, through an expanded Home Battery Pilot described in the Company's most recent electric rate case filing. Use of the batteries for electric supply and wholesale market purposes is one use case being evaluated as part of the CS storage pilot, but the Company also expects to study NWS use cases as well. CS storage may also work to defer capacity upgrades on distribution assets. CS storage can also be used to provide islanding capabilities – providing customers with power during an outage, capturing an additional use case of system reliability and resilience.

Additionally, the Company is working with C&I customers on developing combined solar-and-storage and storage-only CS pilots, with similar goals as the other CS storage pilots discussed above. As these and other efforts evolve, they will be integrated into the Company's NWS portfolio.

The Company has also been building and operating US storage for several years, beginning with its Parkview battery in Kalamazoo and Circuit West battery in Grand Rapids. Other US storage projects will have the potential to act as NWS, in addition to their other use cases. The Company has been developing a portable battery that can be installed at a substation in order to defer capacity upgrades for a period of time, and then can be moved on to another substation to fulfill the same purpose. The Company is also planning to deploy a battery attached to an industrial park to test using a US battery for islanding purposes, while keeping power on to customers in the event of an outage. Another battery, scheduled to be deployed in 2022, will be located between two circuits and will better enable automatic switching between the circuits, another potential use of a battery as a reliability-boosting NWS.

As discussed earlier in the section of this report on IRP alignment, the Company's 2021 IRP also economically evaluated DAUD batteries for potential deployment in later years, which would likely coincide with Phase 3 of NWS deployment. That earlier-discussed DAUD battery evaluation illustrates one obstacle to widespread NWS deployment. For that evaluation, the Company was able to identify 23 LVD substations with the potential to become overloaded due to growth in existing load over a 20-year period. The Company's total population of LVD substations approaches 1,100; in other words, there are very few easily-identified locations for NWS deployment even if NWS capabilities were fully mature. As noted in the earlier section of this report on load forecasting and in the later section on the LVD Substations Capacity sub-program, most LVD Substations Capacity projects respond to overloads that have already happened or that are known to be imminent due to new business load – similar to what has happened at Four Mile.

To date, the Company has earned a return on its pilot investments through different means. For example, the spending on the Swartz Creek and Four Mile pilots receive an existing financial incentive mechanism. As NWS begin to be considered as a regular alternative for projects, the Company may propose other incentive mechanisms, such as shared savings or other constructs, to appropriately reflect the customer and grid value provided to customers.

vi. Strategy

The Company will build upon its suite of NWS pilots, gaining insights and developing capabilities. The Company will integrate its developed processes, tools, and analytical abilities into planning and operational processes and activities. The Company expects the knowledge and processes of a highly cross-functional team, including Electric Grid Infrastructure, Customer Experience, Rates, Regulatory, and Strategy to continue to mature, leading the Company to develop its ability to scale NWS pilots into scaled projects, enabled by pilot learning and new capabilities. The Company will continue to develop its capabilities through ongoing NWS pilots, using a Pilot, Integrate, Scale cycle:

- **Pilots** build capabilities and insights;
- The Company develops new **analytical capabilities and tools;**
- These are **integrated** in the planning processes;
- NWS are **scaled up** based on pilot results; and
- The **regulatory framework** should evolve to support NWS growth.

vii. Framework: Getting from Current State to Future State

As the Company moves from Phase 1 into Phases 2 and 3, it will evolve its solutions, approaches, and capabilities:

Evolving Solutions: Initial pilots have focused on capacity upgrade deferral, leveraging existing EWR and DR program offerings. CS storage is being added in late Phase 1 as a separate pilot effort, along with US storage, since EWR and DR alone may not be sufficient to address capacity issues. Both will continue into Phase 2. In Phase 2, the Company will also begin layering in pilots using solar generation, back-up generators, and electric vehicles for potential NWS applications. In Phase 2, the Company will also begin moving beyond the capacity deferral use case and evaluating reliability and resilience use cases.

Evolving Approaches: To date, the Company has approached NWS in a program-based manner. In the future, the Company may consider investigating pricing and third-party procurement approaches as well. However, successful use of these other approaches, like the use of utility programs, relies on an appropriate regulatory framework that ensures that third parties meet their obligations without compromising reliability, and that provides proper incentives for the utility, accounting for foregone capital investment and the fact that deployment of an NWS, if chosen, may provide additional customer benefits through a lower-cost solution than a traditional investment. The future regulatory framework should make proper use of metrics and performance tracking (avoided capacity, improved reliability, etc.) to support NWS frameworks and incentives.

Evolving Capabilities: In Phase 1, the Company is refining suitability criteria for capacity deferral projects through lessons learned in the Swartz Creek and Four Mile pilots. As the Company progresses into evaluating reliability and resilience and other use cases, it will also develop and refine a set of suitability criteria to identify possible pilots and projects in those areas. It is critical to note that NWS are not expected to allow *deferral* or *avoidance* of traditional reliability projects in the same way that capacity projects may be deferred. That is, the Company will continue investing to replace deteriorated assets, mitigate against animal intrusions, and make other related traditional investments. However, NWS may be able to *improve* or *enhance* reliability and resilience if islanding and microgrid capabilities can be developed.

For each use case, the Company will develop the ability to screen potential projects to determine if a given NWS is feasible, after which NWS options could be evaluated against traditional distribution solutions to determine cost-effectiveness. The economic case for various NWS will only be improved by adding multiple components to the value stack; for example, batteries that can bid into an ancillary services market could provide increased customer value.

viii. Future State

In Phase 3 and beyond, the Company expects to deploy scaled NWS projects, with a continuation of new pilot activity and deeper integration. With the work occurring in Phase 1 and planned for Phase 2, it is anticipated that NWS projects of various types and sizes would be identified in the integrated planning process and selected via an integrated analysis which would identify the best method to achieve the specific project goal(s). The scope of NWS and DER projects will continue to evolve. Industry trends and best practices for NWS will also continue to inform the Company's development and use of NWS. From an operational perspective, NWS will become part of the planning and operational environment. The Company sees value in NWS and a role for NWS in an integrated distribution planning framework. The extent to which NWS are operationalized will depend on pilot results and the ability to scale those results.

FIGURE 71

BREAKDOWN OF NWS PHASES

	Phase 1 (2017-2021) **Test ability to defer capacity projects with targeted marketing of existing EWR/DR programs**	**Phase 2 (2022-2024)** **Expand on capacity project deferral to include reliability improvement**	**Phase 3 (2025-2027)** **Future State**
Solution/Technology • Grow portfolio of NWS technologies (experience, applications)	*Pilots* • Energy waste reduction (pilot) • Demand response (pilot) • Customer-sited and utility-scale storage (pilot) • Conservation Voltage Reduction (scaling up through IRP)	*Pilots + Projects* • Energy waste reduction (projects) • Demand response (projects) • Customer-sited and utility-scale storage (pilot) • Back-up generators (pilot) • Solar PV (pilot)	*Projects* • Combination of technologies
Use Cases • Fully understand viability of NWS to solve varied grid needs	• Capacity deferral	• Reliability and resilience improvement (early studies) • Capacity deferral (projects)	• Reliability and resilience improvement (projects) • Capacity deferral (projects) • Additional use cases to be identified
Capabilities, Analytics and Tools (Customer, engineering, operations, planning) • Build cross-functional NWS planning capabilities and processes • Develop, implement and integrate tools necessary to evaluate and plan for NWS	• Establish preliminary suitability criteria • Develop new functional and cross-functional processes • Create data pipeline (existing and new needed for suitability criteria) • Establish initial screening study methodologies and algorithms • Circuit level events – initial testing • Circuit level forecasting – initial testing • Initial DERMS deployment	• Refine suitability criteria based on pilot learnings, new data sets, and for new use cases • Refine and integrate cross-functional processes • Embed pilot learnings into planning processes • Integrate data systems • More granular data analytics • Testing of different procurement models • Testing DERMS	• Integration of NWS planning as regular tool in supply and distribution planning • Mature and scale suitability criteria • Mature and seamless cross-functional operating model • Algorithms and tools working together seamlessly
Regulatory framework • Establish regulatory framework that aligns interests of customers, utilities and other stakeholders and fairly incentivizes NWS deployment	• Pilot collaboration with NRDC • Meeting with Staff • Annual DR reconciliation cases • Incentive earned for EWR pilots	• Develop appropriate regulatory framework governing third party obligations and setting proper utility incentives	• Further refining regulatory framework

B. Hosting Capacity Analysis

The MPSC's August 20, 2020 Order in Case No. U-20147 defines hosting capacity as the "amount of distributed energy resources ('DERs') that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades." Id. Within that context, the MPSC further defines a DER as "a source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system." The Company supports these definitions and is developing its DER-related activities, including HCAs to align with these definitions.

The Company interconnects DERs to its distribution grid through an MPSC-regulated interconnection process, with provisions that differ based on the size of the resource. When a proposed DER goes through this interconnection process, the Company performs a resource-specific analysis to ensure that the interconnection will not cause any reliability or capacity issues, and, if it will, to identify any necessary distribution system upgrades. Depending on the size of the proposed DER, this analysis may range from a relatively simple screen up to a detailed study.

Many parties have become interested in HCAs as a means to improve this process. HCAs have the potential to proactively identify many locations on the distribution system that have a likely probability of accommodating DERs prior to a resource-specific study being performed. When hosting capacity is analyzed, and the data published, customers and DER developers can have a better idea of where to propose interconnections. While resource-specific analyses would still be required before interconnection, HCA information may help illustrate areas of the distribution system that are particularly amenable to DERs, as well as areas that are not amenable without system upgrades. By providing this information, customers and DER developers can avoid proposing interconnections and incurring the associated costs of studies in those areas that cannot easily accommodate DERs with existing infrastructure and configuration.

Additionally, as distributed solar generation, distributed battery storage, and potentially other types of DERs increase within the Company's electric supply portfolio, the Company will need to optimize siting of utility-scale DER assets. While an IRP can identify optimal DER penetration levels on a system-wide basis, an IRP will not identify specific locations for those DERs on the distribution system as a means of improving thermal, voltage, or other system performance conditions. Siting evaluations are a function of distribution planning, and HCAs have the potential to offer valuable insight.

While multiple use cases of HCAs may exist, discussions with stakeholders and MPSC Staff since 2018 have indicated that DER interconnection should be the first use case that utilities in Michigan develop. These discussions further indicated that the preferred approach is for utilities to pursue a phased approach to developing HCA capabilities, with two primary phases:

- Phase I: A base-level approach with a zonal go/no-go map; and
- Phase II: Specific, detailed analyses on areas of the distribution system with high DER penetration, incorporating this information into a more detailed map with circuit voltage-level information as DER penetration continues to increase.

The Company has completed its Phase I analysis, and the results are discussed below. Phase II is underway, which is also discussed below.

i. Phase I: Base-Level Go/No-Go Analysis

To perform an initial Phase I analysis consistent with stakeholder discussions, MPSC Staff recommendations, and MPSC Order language, the Company reviewed a total of 2,018 LVD circuits, representing essentially the entire LVD system. For this initial analysis, the Company identified circuits that could likely accommodate 2 MW of additional DER, because 2 MW is the largest single DER that would likely have a successful interconnection to an LVD circuit, meaning that a circuit that could accommodate 2 MW would constitute a "go" area. The "no-go" areas are subsequently those not identified in this Phase I analysis. This cutoff excludes the largest Category 5 interconnection requests under current interconnection standards, which are generally connected to substations or the HVD system rather than LVD circuits.

To identify these LVD circuits, the Company studied the voltage, maximum and minimum loads, and other circuit characteristics of the first protective zone of each general distribution circuit on the system (excluding customer-dedicated circuits), assessing whether or not each zone would meet several attributes, with all attributes needing to be met for the zone to be classified as a "go." The analysis was limited to first protective zones to reduce complexity, to avoid coordination with and potential upgrades related to existing protective devices, and to avoid concerns about DERs affecting automation loops. The Company screened for the following attributes:

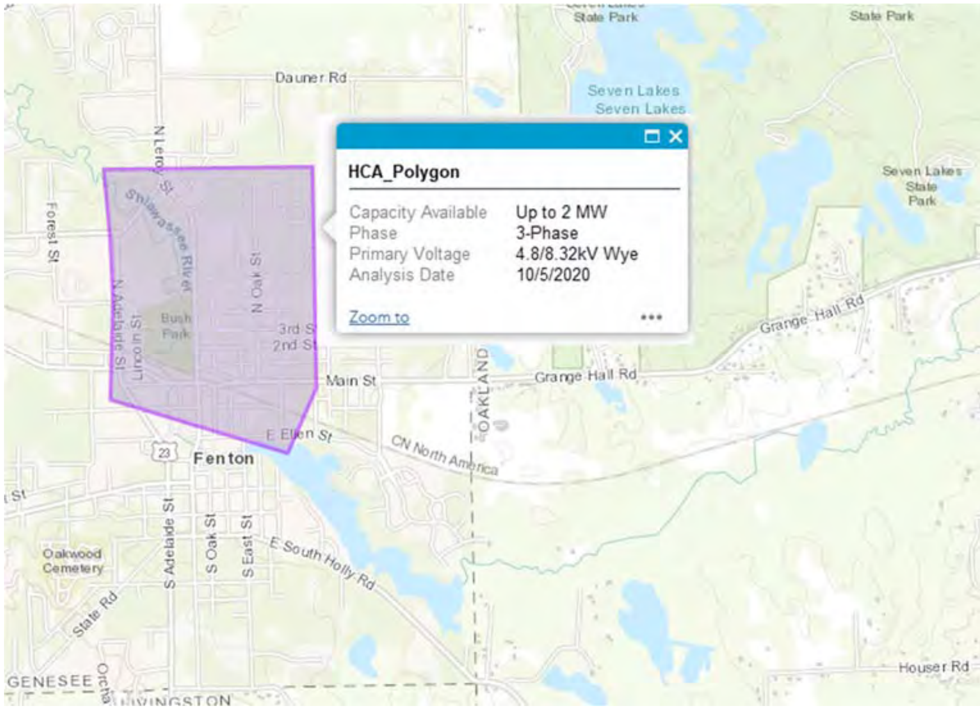
- 40% of the peak load must be greater than 2 MW (to avoid analytical complexities related to reverse power flow into a substation; if a circuit meets this threshold, it should not require a Direct Transfer Trip);
- Voltage must be grounded wye;
- DSCADA must be installed; and
- The minimum short-circuits and system strength criteria must be met (≥333 kVA/Volt drop at 0.95 power factor), to ensure that the circuit's short-circuit and system strength meets the 5% voltage fluctuation requirement as defined by the Michigan generator interconnection requirements.

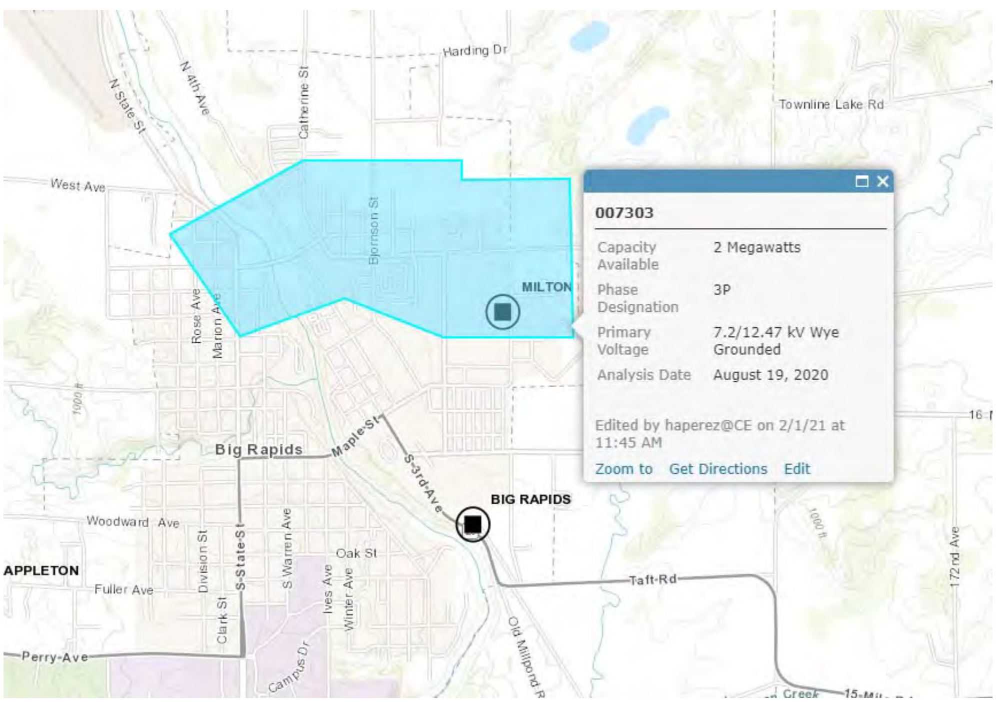
Based on this screening, the Company identified 301 "go" zones. For each zone, the Company has produced a map to identify the location on the system. All of these maps, with supporting data, will be posted on the Company's interconnection website

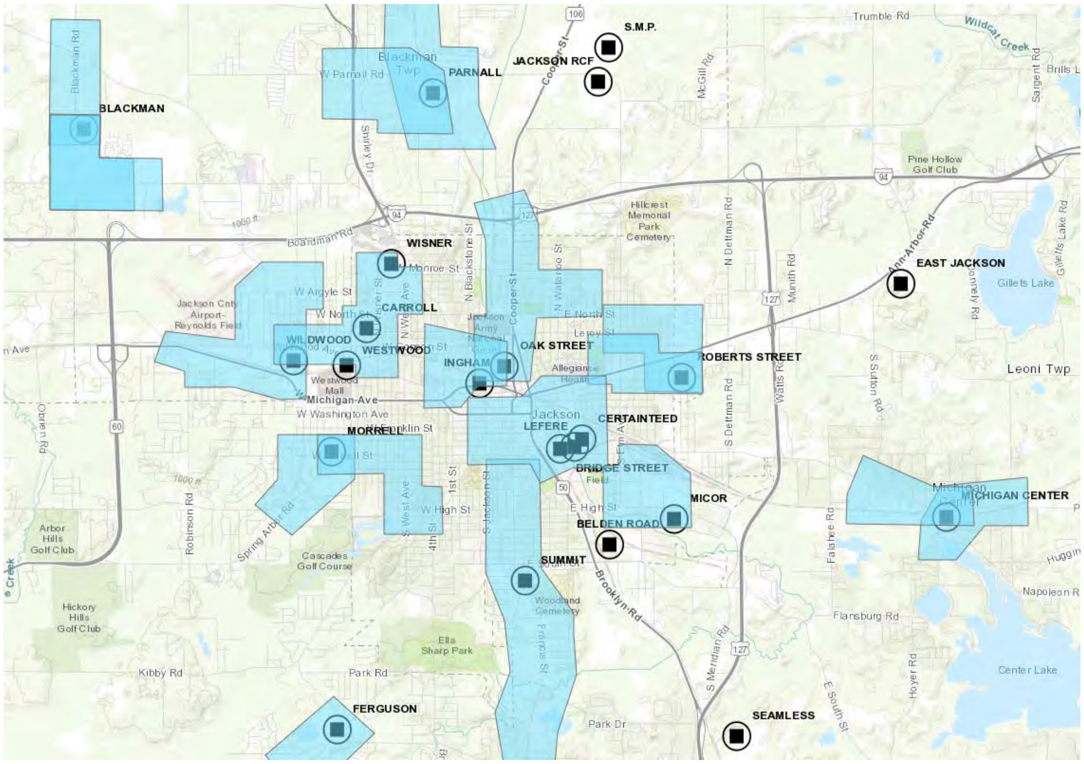
([https://www.consumersenergy.com/residential/renewable-energy/generation-interconnection-information)](https://www.consumersenergy.com/residential/renewable-energy/generation-interconnection-information), and examples of these maps are shown in Figure 72 below.

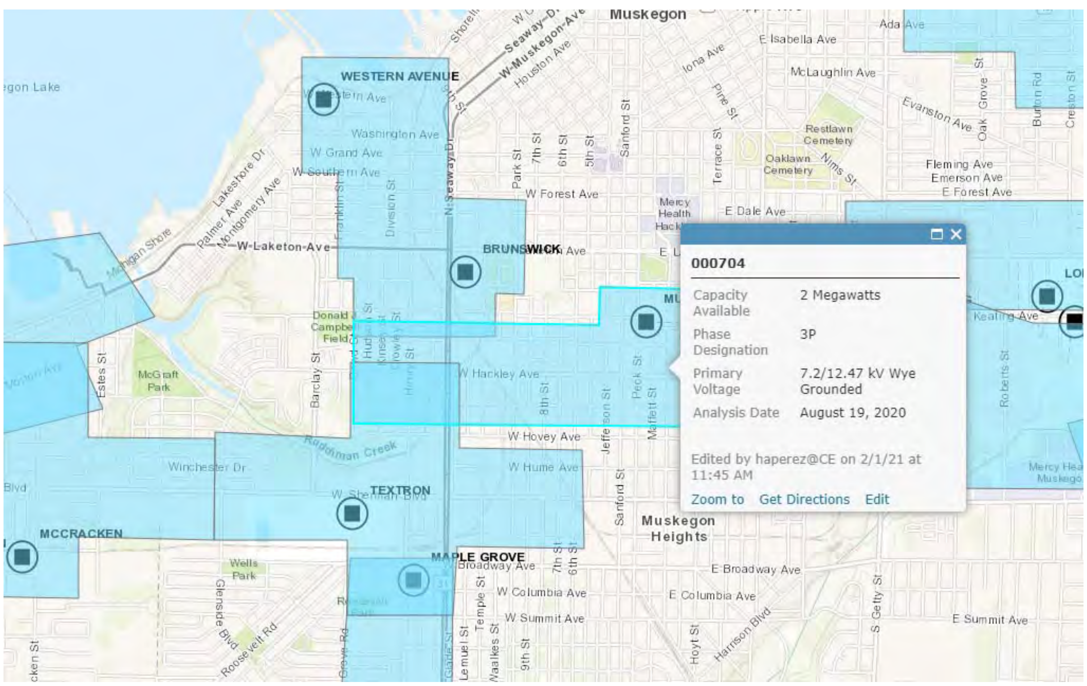
FIGURE 72

EXAMPLES OF PHASE I HCA MAPS ILLUSTRATING "GO" ZONES









The Company plans to update this Phase I zonal analysis on an annual basis, with results to be published on its interconnection website. It is important to note that, even in a “go” zone, any proposed DER interconnection must still go through the interconnection process in order to ensure full compliance with interconnection standards to ensure that reliability is maintained.

To date, the Company does not yet have any areas of high DER penetration on its system that would trigger the specific, detailed circuit analysis envisioned as part of Phase II of HCA development. However, the Company is still moving into more detailed analyses, as discussed below.

ii. Phase II: Specific Detailed Circuit Analysis

In the next phase of developing an HCA process, the Company will make use of a tool developed by the EPRI called Distribution Resource Integration and Value Estimation ("DRIVE") (https://www.epri.com/pages/sa/drive), to conduct higher-resolution analyses of its circuits. The EPRI DRIVE application interfaces with the Company's existing CYME (http://www.cyme.com/software/; CYME was formerly known as "Chinh Yvan Micro Engineering") power engineering software and circuit models to perform a series of load flow and short-circuit simulations at various user-defined loading levels. (Refer to the section of this report on the LVD Lines Capacity capital sub-program for further discussion on CYME.) Simulation solutions, feeder topology, and other model attributes are extracted from CYME, and used to conduct a research-refined HCA, which is intended to standardize calculation methodologies and results across the industry, regardless of the planning tool being used. For Phase II, the Company will evaluate the Phase I "go" circuits in EPRI DRIVE to provide more detailed results that include the minimum and maximum available hosting capacity on each of the respective circuits. (Note that while all Company circuits can be studied with DRIVE, the initial focus will be on the Phase I "go" circuits, because these have already been identified as strong candidates for having available hosting capacity.)

In 2021, the Company has developed its capability to use EPRI DRIVE internally, and is performing hosting capacity analysis on a subset of circuits to evaluate resources required for systemwide analysis, and to fine-tune the many user-defined input parameters to maintain alignment with the Company's existing interconnection standards. As Phase II progresses, the Company will eventually be able to use DRIVE to regularly run HCAs on the system using its existing CYME circuit models, using different load scenarios, and updating periodically. (However, not all of these future-state capabilities will necessarily become available at the same time.) As this process matures and the Company fully integrates its CYME databases with DRIVE, DRIVE will be able to analyze a circuit more quickly.

DRIVE will help the Company validate the accuracy of its Phase I analysis, potentially allowing the Company to refine its screening criteria, which could allow more circuits to be included in HCAs going forward.

As of this filing, the Company is beginning to move into Phase II by using DRIVE to run HCAs on selected circuits on a demonstration basis, and the Company can provide illustrations of how this works for three circuits.

For each of the three circuits, the DRIVE Model C Interface script was executed against the current year CYME base case study, modeled at historical peak loading conditions observed while the circuit was in its normal operating configuration. Load flow and short-circuit simulations were performed at the peak loading level described above, then again with the peak loading level scaled by a factor of 0.2 per unit to represent the circuit's minimum loading level for the hosting capacity analysis.

While using a global scaling factor of 0.2 per unit streamlines the underlying analytics, it is probable that available generation hosting capacity results are conservatively constrained by overvoltage. Once fully mature, the Company intends for Phase II HCAs to consider the actual historical minimum load observed during the hours that the future resource would be exporting generation to the system. For this analysis, solar PV resources were explicitly considered, and as such, minimum loads during the overnight hours are excluded. Though not applicable for Phase II HCAs, identification of bounded minimum loading levels may require further development for circuits fed from substations without DSCADA installations in future HCA phases. As with the peak load level parameters, minimum load will also need to be defined based on the normal operating configuration of the circuit.

After performing simulations at both loading levels in CYME, the load flow and short circuit solutions, circuit topology, equipment characteristics, settings and operating states were extracted to a series of comma separated value files and processed by DRIVE for hosting capacity calculations.

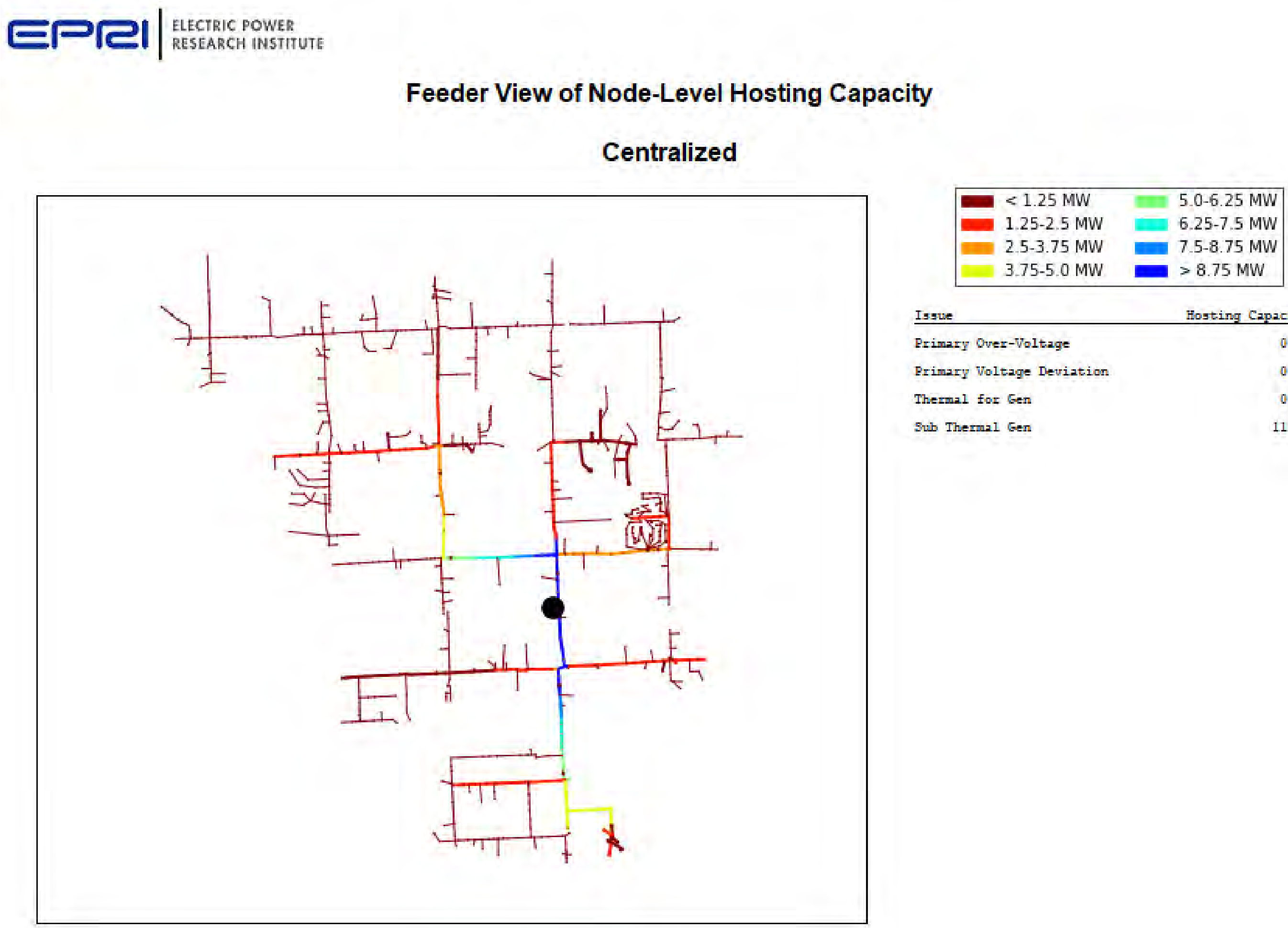
DRIVE includes pre-populated default parameters within the application, based on prior EPRI research and input from industry stakeholders. Hosting capacity calculations require complex analytical processes that rely on many variables, and results vary significantly based on how those variables are defined. The Company has leaned heavily on the pre-populated values for preliminary Phase II HCAs, though a few adjustments have been made to tailor the analysis to unique distribution system characteristics and insights gained from detailed interconnection studies to date. Continued refinements to the methodology and assumptions described in this section are anticipated as Phase II HCA development matures.

The illustrations in Figure 73 through Figure 75 show how fully matured Phase II HCAs will indicate the baseline generation hosting capacity on each of the Phase I "go" feeders, defined at the circuit level. The MW values depicted on the map do not include hosting capacity reductions for existing DERs. Existing DERs will need to be considered in future HCA phases as penetration increases. Substation and line voltage regulators were allowed to operate, but tap limits were reduced from the typical +/-10%, to +/- 5% to reduce potential for excessive tap operations due to the intermittent output of PV resources. The underlying analyses considered DER impacts related to four primary system constraints:

- Primary Over-Voltage: Voltage at any location on the feeder not to exceed 1.05% of nominal;
- Primary Voltage Deviation: Voltage at any location not to change by more than 3%;
- Thermal for Generation: Power flow through any device or line section toward the substation not to exceed the device or conductor/cable rating; and
- Sub Thermal Generation: Power flow from the feeder through the load side of the substation transformer not to exceed 100% of the transformer nameplate rating.

FIGURE 73

ILLUSTRATIVE PHASE II HCA MAP – CIRCUIT LEVEL DETAIL



Issue	Hosting Capacity
Primary Over-Voltage	0.72
Primary Voltage Deviation	0.72
Thermal for Gen	0.02
Sub Thermal Gen	11.56

FIGURE 74

ILLUSTRATIVE PHASE II HCA MAP – CIRCUIT LEVEL DETAIL

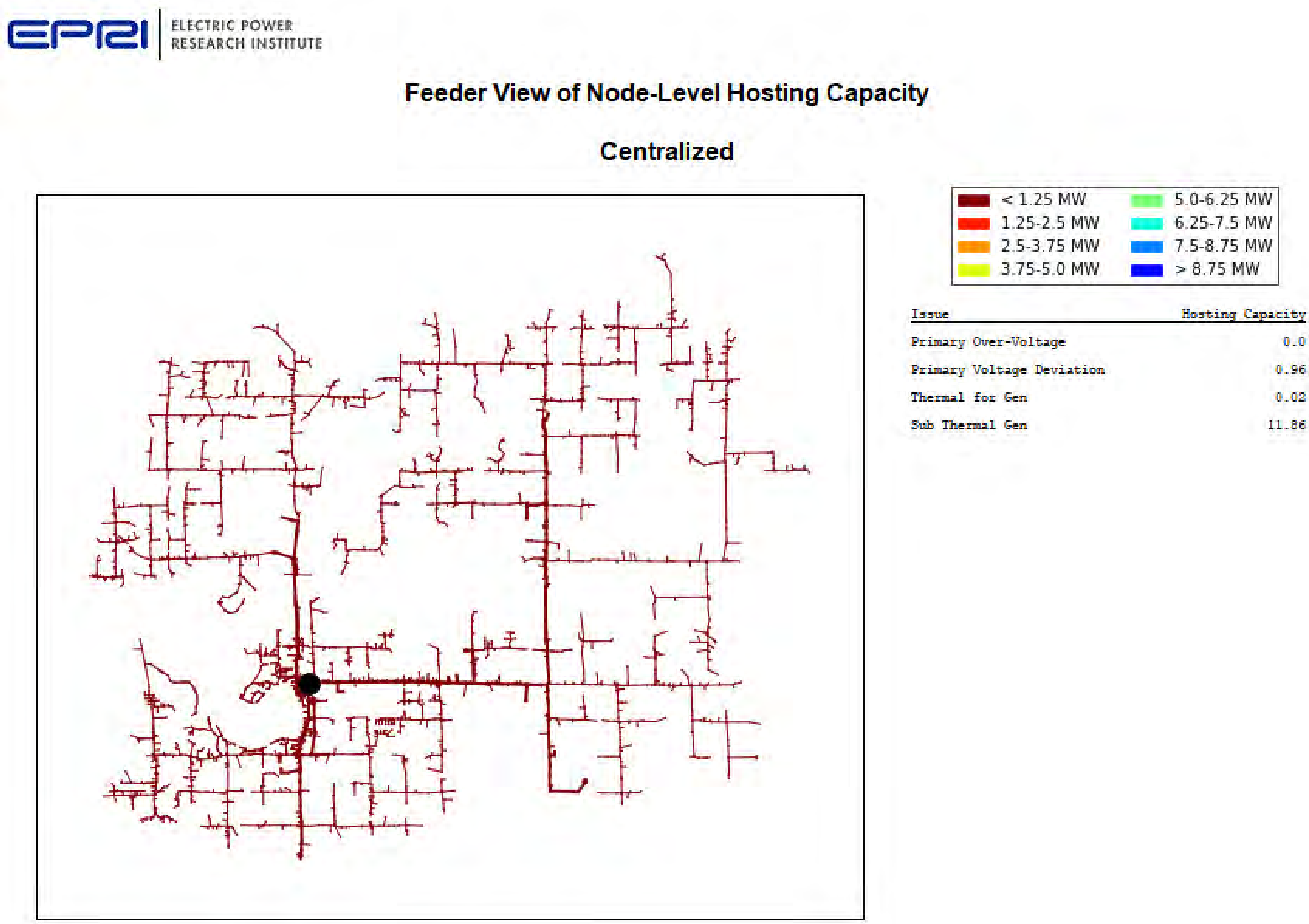
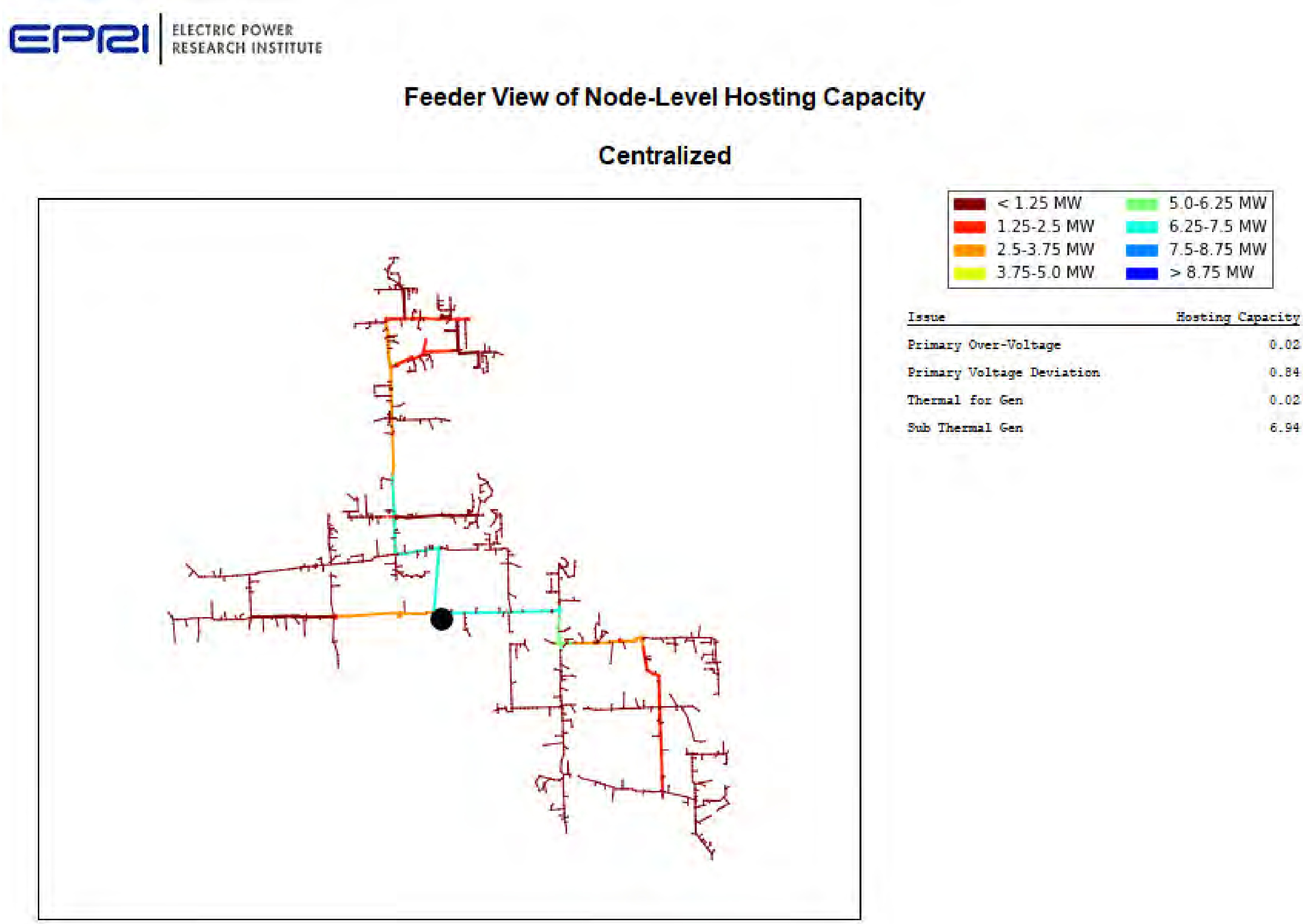


FIGURE 75

ILLUSTRATIVE PHASE II HCA MAP – CIRCUIT LEVEL DETAIL



VII. Five-Year Distribution Spending Plan – Capital

A. Intro to Capital Section

Over the next five years, the Company plans to invest between $708 million and $865 million per year in capital on the LVD and HVD systems. These investments are tied to the five distribution objectives of reliability, safety and security, sustainability, control, and cost. The Company's capital investments are managed utility-wide, so fluctuations among specific programs and sub-programs may take place to respond to emergent needs. The five-year plan presented below is the Company's best representation of expected distribution capital investments as of June 30, 2021.

As discussed earlier in this document, the Company makes capital investments under two broad classifications, known as "unplanned" and "planned." Spending that responds to demand-driven, customer-driven, or other emergent needs is classified as "unplanned." These investments are not strictly "unplanned" as the Company does anticipate it will have to make these investments, to replace failed equipment and add new customer connections to the system. However, due to the emergent nature of these needs, the Company's investments can be difficult to plan with specificity in advance, because the Company cannot plan for an exact number of equipment failures or new customers, nor where such needs will occur. Instead, the Company generally forecasts the needed investments for these "unplanned" programs based on historical actual expenditures, applying growth rates as appropriate based on external trends. These "unplanned" programs consist of New Business, Demand Failures, and Asset Relocations. The five-year plan for this spending is summarized in Figure 76 below.

In addition to the investments addressing emergent needs described above, the Company also plans investments further in advance to proactively improve the grid through reliability improvement projects, capacity upgrades, and investments in new tools and technology. These programs consist of Reliability, Capacity, and Electric "Other." The five-year plan for this spending is summarized in Figure *77* below.

It is important to note that, while the spending presented in these tables represents a robust and well-supported projection of expenditures, future adjustments always remain a clear possibility. Changes to Michigan's economy may impact, in particular, New Business spending and Capacity spending tied to New Business growth. Other factors, such as the impacts of inflation on the price of materials and labor, could affect investments in all programs in the future.

FIGURE 76

5-Year Capital Plan – Unplanned Programs *(All values in $ millions)*								
All values in $ millions	Actual			Plan				
	2018	2019	2020 prelim	2021	2022	2023	2024	2025
Unplanned programs								
LVD Lines New Business	87.1	83.5	86.3	93.1	98.6	107.1	110.3	113.6
HVD Strategic Customers New Business	(6.1)	6.5	6.0	23.5	10	10	10	10
Metro New Business	3.5	7.4	4.5	3.5	3.6	4	4	4
LVD Metering New Business	9.4	13.6	10.5	7.7	9.3	9.8	10.2	10.7
LVD Transformers New Business	11.4	21.6	12.2	12.3	12.6	12.9	13.2	13.4
New Business	105.1	132.6	119.5	140.1	134.2	143.8	147.7	151.7
LVD Lines Demand Failures	66.3	95.7	106.1	83	84	86	87	88
LVD Substations Demand Failures*	20	20.7	8.3	7	7	7	7	7
HVD Lines & Substations Demand Failures*	27.8	24.9	8.2	4.2	4.1	4.1	4.1	4.1
LVD Metering Demand Failures	11.6	11	10.4	9.8	11.8	11.9	12.5	13.1
LVD Transformers Demand Failures	14.6	16.3	14.1	14.3	14.6	14.9	15.2	15.5
Center Suspension Streetlight Conversions**	1.8	2.3	1.1	1.3	3	5	5	10
Metro Demand Failures*	2.5	3	1	1.1	1.1	1.1	1.1	1.1
Demand Failures	144.8	174	149.1	124.4	127.6	130	131.9	138.8
LVD Asset Relocations	34.1	40.4	35.7	48.9	52.5	55.6	58.8	61.7
HVD Asset Relocations	2	(0.4)	0.9	0.9	0.9	0.9	0.9	0.9
Metro Asset Relocations	4.4	6.3	3.3	3.9	4	4.4	4.4	4.4
Asset Relocations	40.5	43.7	39.9	53.7	57.4	60.9	64.1	67
Total Unplanned	290.4	350.3	308.5	318.1	319.5	334.7	343.7	357.5

**These investment categories historically included spending for work that is now classified under the Rehabilitation sub-programs.*

***Through 2020, this investment category funded conversion of mercury vapor streetlights. Beginning in 2021, this spending is for center suspension conversions.*

FIGURE 77

5-Year Capital Plan – Planned Programs *(All values in $ millions)*								
All values in $ millions	Actual			Plan				
	2018	2019	2020 prelim	2021	2022	2023	2024	2025
Planned programs								
LVD Lines Reliability	36.9	35.7	30.7	40.7	45.9	80.8	86.9	95.1
HVD Lines Reliability	42.7	47.8	22.7	63.9	78.4	78.7	78.8	78.6
LVD Substations Reliability	10.2	13.6	13.1	13.3	15.5	15.5	15.5	15.5
HVD Substations Reliability	2.8	4.7	5.9	5.2	5.4	5.4	5.4	5.4
System Protection	3	3.1	3	2.3	2.4	3.3	3.4	3.4
LVD Repetitive Outages	4.4	6.6	4.8	7.7	10.2	10.6	11	11.3
Metro Reliability	1	3.3	3.3	5.6	5.6	7	6	6
HVD Lines & Substations Rehabilitation*	-	-	14	39	40.7	50.7	56	56
LVD Substations Rehabilitation*	-	-	8.9	14.5	13.5	13.5	13.5	10
LVD Lines Rehabilitation	32	22.4	21.4	36.2	53.6	54.6	55.6	56.2
Metro Rehabilitation*	-	-	4.4	4.4	4.6	6	6	6
Grid Storage**	-	-	3.8	6	10	10	10	10
Grid Modernization	22.6	59.2	63.3	71.2	83.4	80.6	65.7	64.2
Reliability***	155.5	196.3	199	312.2	369.4	415.7	412.6	420.2
LVD Lines Capacity	12.3	4.7	9.2	11.3	13.2	12.5	12.7	12.9
HVD Lines & Substations Capacity	16.5	22	21.5	20.3	20.1	24.6	28.4	24
LVD Substations Capacity	15.9	11.2	9.9	14	14	14	14	14
LVD New Business Capacity	10.3	16.5	14.6	12.2	12.4	23.6	19.1	19.5
LVD Transformers Capacity	3.2	2.9	0.8	0.8	0.8	0.9	0.9	0.9
Interconnections**	-	-	0.1	-	0.2	0.2	3.5	6.5
Capacity	58.2	57.3	57.8	58.6	60.3	75.8	78.6	77.8
Computer and Equipment	0.1	0	0	0.1	0.1	0.1	0.1	0.1
Tools	3.8	4.1	5.5	8.9	9	10.1	10.4	11.1
System Control	1	2.3	2.2	6.7	4.9	4	3.2	2.9
Enterprise Corrective Action Plan	-	-	-	0.1	0.8	0.8	-	-
Electric "Other"	4.9	6.4	7.7	15.7	14.8	15	13.7	14.1
Total Planned	218.6	260	264.5	386.5	444.5	506.5	504.9	512.1
Capital Plan	509	610.3	573	704.6	764	841.2	848.6	869.6

**Prior to 2020, work in these sub-programs was funded through Demand Failures.*
***The Grid Storage and Interconnections sub-programs began in 2020.*
****Reliability totals do not include historical spending on a program to replace obsolete analog communications equipment at substations with digital eguipment, , which has been completed.*

The following sections provide details about each of the electric distribution capital programs and sub-programs. Each one has unique objectives and criteria which, taken together, help the Company meet its electric distribution objectives. For each program and sub-program, this report provides details about the five-year capital plan, descriptions of the types of investments and projects in each, and descriptions of the prioritization process used to identify and develop projects.

B. New Business Program

The New Business Program includes the capital costs of connecting new commercial, industrial, and residential customers to the Company's distribution grid. This includes the costs of installing poles, conductors, transformers, and meters, and in some cases entire new substations. In some cases, costs are offset by customer contributions. Because of the Company's obligation to serve customers in its service territory, the Company generally is required to provide the requested interconnections if the customer meets the requirements set forth in the applicable Company tariffs.

In general, the Company does not have advanced knowledge of the projects in New Business as they are emergent in nature. Details for individual sub-programs can be found in the following sections.

i. LVD Lines New Business

The LVD Lines New Business sub-program includes the capital cost of serving new commercial, industrial, residential, and municipal lighting customers. These costs include the necessary overhead and/or underground distribution extensions and enhancements required to complete new service connections, including the cost for new plats and developments. Projects within this sub-program are initiated by customers, whom the Company must serve so long as the requesting party meets the tariff requirements. Customers may be billed for service pursuant to the stipulations of the tariff sheets. In general, the Company does not have advanced knowledge of LVD Lines New Business projects in the preceding year, as the projects are generally completed within the same year that they are requested, and the projections for installed units and investment are based upon historical activity with adjustments for anticipated variations in business.

For the next five years, the Company plans to invest between $93 million and $110 million in the LVD Lines New Business sub-program each year, based on forecasted service installation volumes, as shown in Figure 78 below. Costs per new service connection have been increasing in recent years, as discussed more below.

FIGURE 78

LVD LINES NEW BUSINESS CAPITAL INVESTMENTS

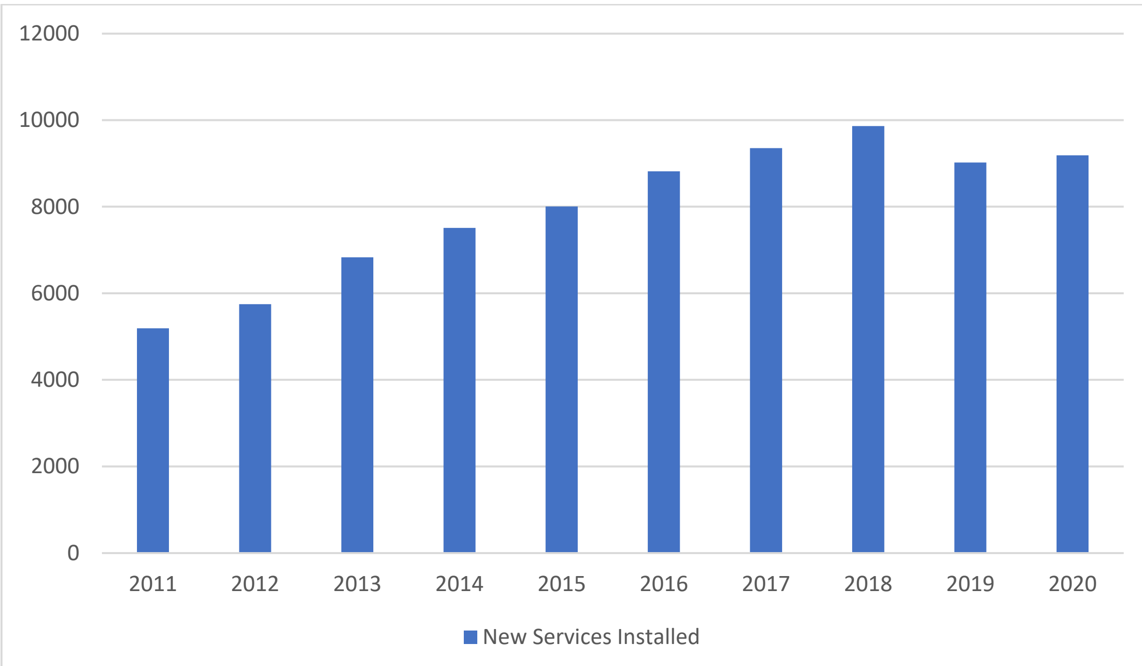
5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
Total Investment	**93.1**	**98.6**	**107.1**	**110.3**	**113.6**

Projections of Service Installation Volumes

New business is often correlated with Michigan's overall economic health, and projected investment needs for the LVD Lines New Business sub-program are based primarily on expected new housing starts in the Company's service territory. Since recovering from the economic downturn in 2012, service installation volumes have increased steadily, albeit with a dip in 2019, as shown in Figure 79 below.

FIGURE 79

LVD LINES NEW BUSINESS SERVICES INSTALLED



The most recent data from the Michigan Home Builders Association ("MHBA") indicates that new housing starts, and therefore new service requests, will continue at recent higher levels, with requests in 2021 and 2022 in line with or slightly higher than those in 2019 and 2020 and well above the levels seen in the early and middle parts of the last decade. This is shown in Figure 80 below.

The COVID-19 pandemic has not slowed the projected housing starts for the state of Michigan. As shown in Figure 80 below, the number of single family housing permits dropped somewhat in the early part of 2020, when various stay-at-home orders temporarily significantly reduced construction, but the data shows a rebound in activity since then, with continued projected increasing going forward. This data from the MHBA supports the projection of new service connections. In 2020, from May through December the 10,451 permits issued outpaced the 10,060 permits (an increase of nearly 4%) issued during the same period in 2019. MHBA data compiled by the US Census Bureau shows a total of 13,876 single-family home permits, issued across Michigan, from January through November 2020. In addition, the Company saw an increase in new customer requests initiated in the Company's Energy Request Center, with 2020 requests exceeding 2019 requests by 12%, and the Company installed more service connections by 2% year over year from 2019 to 2020.

FIGURE 80

SINGLE FAMILY HOUSING PERMITS ISSUED

The Company assumes that Michigan's economy and housing market will continue to expand at a rate consistent with historical trends.

<u>Recent Unit Cost Trends</u>

As shown in Figure 81 below, there has been a significant increase in unit costs since 2016 due to a large increase in line extensions to accommodate new services, along with an increase in the lengths of services themselves. To illustrate this, in 2014 the Company installed 2,032,000 feet of line extensions and 740,000 feet of services in response to new service requests. By 2019, this had increased to 2,441,000 feet of line extensions and 1,012,000 feet of services. This raw increase in length has raised both unit costs and total program costs. Furthermore, the Company is investing, at customer request, in new underground infrastructure to support new service connections. In 2014, 67% of the Company's line extension length to accommodate new services was overhead, with 33% underground. By 2019, that had shifted to 52% overhead and 48% underground, and in 2020 this shifted further to 49% overhead and 51% underground, further increasing unit costs and total program costs.

Prior to 2017, the Company collected mandatory charges for the difference in cost between overhead and underground facilities as a contribution for all general service connections. In 2017, Rule 511 of the Michigan Administrative Code was changed so that the Company can no longer collect mandatory underground charges. This promotes the construction of underground facilities, which are less impacted by acts of nature, and enables the Company to be competitive with alternative providers in scenarios where its facilities are in similar proximity to other utilities prior to making an initial service connection.

Additionally, in Case No. U-18039, the Commission issued a June 9, 2016 Order that allows the Company to waive certain contribution in aid of construction ("CIAC") requirements, including those related to the difference in costs between providing underground and overhead service, for customers if the revenues from the new load will offset the Company's costs in providing the new service.

FIGURE 81

LVD LINES NEW BUSINESS UNIT COSTS

	2015	**2016**	**2017**	**2018**	**2019**
New Services	8,004	8,818	9,353	9,864	9,023
Cost/Service	$5,700	$4,900	$7,000	$8,900	$9,200

Benefits

Fundamentally, new customers benefit when they are connected to the Company's distribution system through the LVD Lines New Business sub-program because customers' homes, businesses, and other facilities receive access to the grid and the electricity that it provides. Economic growth in Michigan depends on the ability of new residential, commercial, and industrial facilities to access utilities, including electricity. The Company is committed to providing a new service installation to every customer who requests it, and the requested spending level will allow the Company to do that.

ii. HVD Strategic Customers New Business

Our HVD Strategic Customers New Business sub-program meets the needs of large C&I customer new business requirements that are too energy-intensive to be served by the area LVD system. Typical investments for this program include dedicated substations and interconnections of dedicated substations to the HVD system with poles and conductors. The Company plans for and begins to develop these projects as it is made aware of needs, based on customer activity. The timeline from a customer request notification to final connection can vary from six months to two years. For 2021, the Company is planning four new substations, two 46 kV line relocations, approximately 0.1 miles of new 46 kV lines, and approximately 2.8 miles of new 138 kV lines. Some projects in our current five-year plan include:

- For a customer in southwest Michigan, the Company is building a new 138 kV substation, two new 1.3-mile 138 kV lines, and relocating two existing 46 kV lines;
- For a customer in northwest Michigan, the Company is building a new 138 kV substation;
- For a customer in mid-Michigan, the Company is building a new 138 kV substation and a new 0.1-mile 138 kV line;
- For a customer in mid-Michigan, the Company is building a new 138 kV substation and a new 0.1-mile 138 kV line; and
- For a customer in mid-Michigan, the Company is building a new 0.1-mile 46 kV line connecting to a new customer-owned 46 kV substation.

The Company's five-year plan for this sub-program is as follows:

FIGURE 82
HVD STRATEGIC CUSTOMERS NEW BUSINESS

5-Year Capital Plan (all values in $ millions)					
Projects	2021	2022	2023	2024	2025
New 138 kV Substation #1	7.4	-	-	-	-
New 138 kV Line #1	2.8	-	-	-	-
New 138 kV Line #2	2.8	-	-	-	-
46 kV Line Relocation #1	0.2	-	-	-	-
46 kV Line Relocation #2	0.4	-	-	-	-
New 138 kV Substation #2	4.3	-	-	-	-
New 138 kV Substation #3	2.3	-	-	-	-
New 138 kV Line #3	0.1	-	-	-	-
New 138 kV Substation #4	2.6	-	-	-	-
New 138 kV Line #4	0.1	-	-	-	-
New 46 kV Line #1	0.4	-	-	-	-
Other expected HVD new business	0.1	10	10	10	10
Total	**23.5**	**10**	**10**	**10**	**10**

While the Company has known projects for 2021, the projected values for 2022 through 2025 are estimated based on expected needed investment, based on historic spending levels. These costs are net of any CIAC made to the Company by customers in support of their project.

Planning Process

The Company identifies projects as they are requested by customers. Customers typically contact the Company's Business Customer Care team, who refers the customer to the HVD planning engineer for the corresponding geographic location. The customer will identify its location, proposed new maximum demand, a proposed schedule for new load to come online, and other information. The HVD planning engineer performs studies and develops conceptual cost estimates for any required new or upgraded Company facilities to serve the new load, including any CIAC costs applicable to the customer. If agreed to by the customer, a schedule for the work is developed.

Customers may also initiate service inquiries through the Michigan Economic Development Corporation (or any of several local community economic development organizations). These groups then submit a request for proposal ("RFP") to the Company's Economic Development group (also part of the Business

Customer Care team). These RFPs are very similar to a service inquiry through the Business Customer Care team, except that the customer information is typically confidential at these early stages, and there may be multiple alternative locations to review, instead of just one. The timeline for completing these RFPs is very short (several days or less), and very high-level conceptual costs and timeframes for proposed facilities are provided. If the prospective customer is interested in pursuing a location based on the information in the RFP, the same service inquiry process as described above begins for that location.

The Company typically receives a customer service inquiry prior to a completed customer agreement. These inquiries give the Company an indication of potential customer needs, but there is no commitment from the customer to move forward with a project until a customer agreement is completed. Therefore, while the Company does have some advanced indication of potential customer needs prior to a completed customer agreement, the Company will not have certainty that the project will move forward until a customer agreement is completed. The time between when a customer service inquiry is received and when a customer agreement is completed can vary greatly ranging from two or three months to several years or more and is largely reliant on the customer's schedule and customer's decision to move forward.

Project Prioritization and Selection

All customer service inquiries are evaluated, analyzed, and given an equal opportunity to proceed. The Company manages the projects generated in this program to meet the customers' needs, and individual projects are not promoted or deprioritized relative to other projects in this program.

Customers may have to contribute toward the infrastructure investments in this program under the CIAC tariff, and this can be a key consideration for some customers. The Company uses this tariff to determine the level of contribution and to support the growth of business customers of all sizes. This tariff uses a growing customer's new revenue to offset a portion or all the required upfront utility infrastructure costs to receive service. This approach insulates other customers from paying for the electric service requirements of a growing business while also lowering the specific business' upfront utility investment. Ultimately, it is the customer's decision to proceed.

Benefits

The projected expenditures in the HVD Strategic Customers New Business sub-program are needed to respond to customer requests in order to allow those customers to further develop their businesses, and thereby benefit the broader economy of the state of Michigan. Increased new large customer connection and load additions provide the benefits of job development and other state and local revenue streams associated with business expansion. Additionally, all Company customers benefit from these large customer additions – by increasing total load, utility costs are spread across a larger customer base.

iii. Metro New Business

The Metro New Business sub-program responds to electrical energy needs of new construction and renovation of existing locations served by the Company's Metro underground territories. The Company typically needs to extend both the underground civil infrastructure, such as ductwork, and the electrical system to accommodate new business requests.

Metro New Business customers are connected to the system at no cost in accordance with rate administration and billing rules in the Company's MPSC-approved tariffs (C6.2 Underground Policy, Part F). These customers commonly fall into two categories: (i) new construction; and (ii) extensive remodeling of an existing building or conversion of a building from office or commercial use to mixed use or residential. New construction involves a new building on either a vacant site or following a complete tear down of an existing structure. For an extensive remodel of an existing building, the existing structure of a building is intact, but the electrical systems and service from the utility are undersized, due to new building usage or code requirements (e.g., fire pump, HVAC, etc.). Additionally, converting a building to mixed use or residential use may affect the necessary voltages for customers in the building. Occasionally, a customer with a significantly different load profile intends to occupy an existing space, requiring upgrades to the Company's system.

In some cases, customers contact the Company well in advance, allowing for Metro New Business project costs to be determined and planned for in longer-range spending forecasts (see known projects for 2021 and 2022 in Figure 83 below). It should be noted that even with advance notice, customers' respective developments may take years to come to fruition, as customers seek funding and deal with other issues relative to economic development in urban core areas. Therefore, even advance Metro New Business notice projects can have fluid timelines. In other cases, customers contact the Company later in their development process, with desired service in the near future, meaning those Metro New Business project costs cannot be accounted for in longer-term forecasting. Therefore, the Company also uses analysis of historical trends and data to forecast the level of investment needed in this sub-program.

The Company's five-year plan for this sub-program is as follows:

FIGURE 83

METRO NEW BUSINESS CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Projects	2021	2022	2023	2024	2025
KZO – Justice Facility	0.5	-	-	-	-
KZO – 234 Cedar St Apts	1.0				
GR – 430 Monroe	0.2	-	-	-	-
GR – City Tower		0.6			
GR – Microcells	0.2	0.2	-	-	-
Flint – Marketplace PH 2		0.2	-	-	-
Expected metro new business projects	1.6	2.6	4	4	4
Total	**3.5**	**3.6**	**4**	**4**	**4**

Planning Process and Prioritization

The Company identifies projects as they are requested by customers, as is common throughout the New Business Program. New requests are evaluated by the Metro Planning group based on several impacts that impact design, including:

- Customer voltage required;
- Customer anticipated load;
- Potential future load from customer;
- Potential development of surrounding area;
- Existing system capacity; and
- Existing system condition in area.

Metro New Business connections generally use the following guidelines:

- New business customers commonly fall into two categories – new construction and extensive remodels of existing buildings – as discussed above;
- New business meter location(s) help determine the characteristics of service for the customer. The Company prefers to locate meters outside along the back façade of a building (in the alley way). On occasion, the metering can be in an enclosure (primary metering) or inside the building itself. Depending on the characteristics of service for the customer (e.g., residential or general service), the Company may need to solicit an indemnity agreement from the customer for conductors between the utility load center and the metering bank(s); and
- Some customers and developments require the use of the 'high rise policy'. A high rise is an energy dense, multi-story building that requires a vertical extension of Consumers Energy electrical assets. These investments require the customer to furnish and install conduits and provide an elevator of adequate capacity to move electrical equipment and rooms with adequate floor space and support per Company standards.

Benefits

Metro New Business projects are important not only for the customers impacted, but well-planned projects and new infrastructure may decrease future outage time for neighboring customers when expansion of buildings occur, or surrounding areas are developed. Additionally, increased new customer connections and load additions provide benefits to local communities and to Michigan through development of jobs and other revenue streams associated with business expansions.

iv. LVD Metering New Business

The LVD Metering New Business sub-program supplies meters as needed for new business connections. The LVD Metering New Business sub-program is one component of a single purchase plan, which also includes the LVD Metering Demand Failures sub-program. The Company purchases meters, metering transformers, and meter sockets as part of this purchase plan, with a percentage of the expenditures allocated to the LVD Metering New Business sub-program. The purpose of such purchases is to maintain metering accuracy and to support the demand for metering equipment created by emergent work, including new business and equipment failures. From this single purchase plan, expenditures are allocated between LVD Metering New Business and LVD Metering Demand Failures based on the historical percentage of actual work that was done in each sub-program. The percentage split is reviewed annually based on prior-year actual work, and the percentages are revised if necessary.

This sub-program maintains metering accuracy by replacing meters in service that are non-functional, damaged, or whose accuracy has been questioned by the customer. Those meters are exchanged with recently purchased or calibrated meters that the Company knows to be within Commission accuracy requirements, ensuring accurate registration and billing.

The Company develops its metering purchase plan based on projected activity in the New Business and Demand Failures programs, which are in turn based largely on historical data. In addition to historical data, the Company also considers estimates of new business connections in future years, anticipated levels at which meters in the field must be replaced, and whether replaced meters are retired or refurbished and recycled back into service. The Company's five-year plan for this sub-program, and for the LVD Demand Failures Metering sub-program, is shown below, based on currently effective allocation percentages:

FIGURE 84

LVD METERING CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
New Business	7.7	9.3	9.8	10.2	10.7
Demand Failures	9.8	11.8	11.9	12.5	13.1
Total	**17.6**	**21.1**	**21.7**	**22.7**	**23.8**
Unit Forecast					
	2021	2022	2023	2024	2025
Meters	38,300	39,900	41,500	43,100	44,800
Meter Transformers	1,715	1,784	1,855	1,929	2,006
Meter Sockets	292,000	304,000	317,000	329,000	342,000

Recent Changes in Metering Purchase Plan

From 2012 through 2017, the Company completed a program to deploy smart meters to all customers; during that period, the initial purchase of new smart meters was funded by that special program. After deployment of smart meters ended in 2017, spending on the Company's metering purchase plan returned to a business-as-usual mode, with all metering purchases again allocated to the LVD Metering New Business and LVD Metering Demand Failures sub-programs.

Going forward, the Company's new meter purchases will be largely smart meters, which cost more than legacy meters – the basic cost of a legacy meter was $20, while the basic cost of a smart meter is $125. The Company does expect that more smart meters, when replaced, will be able to be refurbished and recycled going forward, mitigating this higher unit cost to some extent.

The Company will continue purchasing some legacy meters even following the mass deployment of smart meters. The legacy meters in the Company's purchase plan support operation of MV90 meters. MV90 meters essentially provide a type of automated meter reading on some large commercial and industrial customers, by which meter interval data is collected either by a telephone connection or is manually read by a field worker. MV90 meters were determined to be out of scope for initial smart meter deployment for two main reasons. First, the billing tariffs for these customers are complex and would have required extensive hours of programming; since MV90 was already functional, the Company kept these meters out of scope for initial smart meter deployment. Second, some of these MV90 meters have a pulse output to provide real time data to customers and at the time of smart meter deployment, the meter vendor did not offer a smart meter option with pulse output, so the use of MV90 legacy meters was still required.

v. LVD Transformers New Business

The LVD Transformers New Business sub-program supplies the distribution transformers that are part of many new business connections, providing the means to supply electricity to the customer at an acceptable voltage, with the number of transformers needed driven primarily by activity in the LVD Lines New Business sub-program. The LVD Transformers New Business sub-program is one component of a single purchase plan for distribution transformers, which also encompasses the LVD Transformers Demand Failures and LVD Transformers Capacity sub-programs. From this single purchase plan, expenditures are allocated among the three sub-programs based on the historical percentage of actual work that was done in each sub-program. The percentage split is reviewed annually based on prior-year actual work, and the percentages are revised if necessary, so these allocation percentages can shift from year to year based on relative activity levels in the New Business, Demand Failures, and Capacity program areas.

The Company develops its plan by estimating the total number of transformers needed across the three sub-programs, based on historical actual data, with potential fluctuation in individual years based on lines projects in the Company's reactive spending programs, particularly New Business and Demand Failures. The Company estimates a 2% annual average increase in total expenditures on new transformers each year. The Company's five-year plan for this sub-program, and for the other LVD Transformers sub-programs, is shown below, based on currently effective allocation percentages:

FIGURE 85

LVD TRANSFORMERS CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
New Business (45%)	12.3	12.6	12.9	13.2	13.4
Capacity (3%)	0.8	0.8	0.9	0.9	0.9
Demand Failures (52%)	14.3	14.6	14.9	15.2	15.5
Total	**27.4**	**28.0**	**28.7**	**29.3**	**29.8**

C. Demand Failures Program

The purpose of the Demand Failures Program is to address issues related to customer interruptions and failures of equipment on the distribution system. When equipment fails, and customers are interrupted, the Company is obligated to fix the issue and restore customers as quickly as possible. If the Company replaces failed equipment in this process, the capital expenditures take place in the Demand Failures Program. Because of this, the work in all of the Demand Failures sub-programs is emergent; it is planned, prioritized, and completed as issues arise, with specific projects not planned far in advance. Therefore, sub-programs in Demand Failures by their nature do not include lists of anticipated projects, and projects cannot be meaningfully reprioritized on a year-to-year basis. Projected spending is generally based on historical spending and potentially adjusted for observed trends.

Through 2018, the Demand Failures Program also proactively replaced assets that were judged to be at risk of imminent failure by a Company or contractor inspection. Such work was included in the Company's Demand Failures plan in Case No. U-20134, and in other prior rate cases. Following the settlement approved by the Commission in that case, the Company moved all work formerly in the "imminent" Demand Failures Program into new sub-programs referred to as Rehabilitation. This shift was first discussed in a regulatory setting in the Company's rate case in Case No. U-20697. All of the work discussed in the Demand Failures sub-programs below consist of "reactive" work. Those Rehabilitation sub-programs are now in the Reliability Program.

In order to comply with the settlement in Case No. U-20134, the Company reviewed its Demand Failures projects in recent years and determined which were in response to actual failures on the system and which were in response to imminent failures. The Company classified different investment categories as reactive, imminent, or a combination of the two, and assigned those categories to a Demand Failures sub-program or a Rehabilitation sub-program under the Reliability Program. In every case, Demand Failures projects are responding to actual failures, defined as a situation where an asset has physically or electrically failed in some way that has put the system outside of normal operating conditions, causing customer outage(s) and/or a public safety condition, creating a need to repair or replace an asset.

i. <u>LVD Lines Demand Failures</u>

The LVD Lines Demand Failures sub-program includes capital expenditures incurred during customer interruption restoration, or during the repair or replacement of LVD equipment due to unanticipated failure. This includes immediate response to day-to-day equipment failures and capitalization of projects during storm restoration. Projects are not planned far in advance in this sub-program, because the sub-program is meant to quickly respond to equipment failures and customer interruptions that have already taken place. The Company responds to failures on the LVD system throughout the state 24 hours a day, seven days a week, 365 days a year. This includes immediate response to day-to-day failures, capitalization of projects during storm restoration, and response to underground cable failures.

The sub-program historically included investment categories for emergent rehabilitation projects; and for security assessment repairs. Both of these investment categories are now funded in the LVD Lines Rehabilitation sub-program under the Reliability program. The LVD Lines Demand Failures sub-program also historically included an investment category for zonal projects for rehabilitation, voltage improvement, and system protection. That work is now included in the targeted circuit improvement investment category in the LVD Lines Reliability sub-program.

In addition to general service restoration work, the Company replaces failed streetlight fixtures as they fail in the LVD Lines Demand Failures sub-program.

Because the LVD Demand Failures sub-program responds to emergent needs, necessary investment in the sub-program can fluctuate from year to year. When forecasting investment needs for a five-year period, the Company develops its forecasted needs based primarily on historical spending on failures, accounting for observed trends.

The Company's five-year investment plan for this program is as follows; the plan assumes a flat number of orders from 2022 forward for planning purposes, with a 1% annual cost increase for inflation:

FIGURE 86
LVD LINES DEMAND FAILURES CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Service Restoration Orders	63	64	65	67	67
Streetlight Failures	19	20	20	21	21
Total	**83**	**84**	**86**	**87**	**88**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Number of Service Restoration orders	20,145	20,145	20,145	20,145	20,145
Number of Street Light Failures	19,700	24,675	24,675	24,675	24,675

Service Restoration Activities

Once a failure or other damage to the system has occurred, the Company prioritizes its response by categorizing damage by severity, as either a Priority 1 ("P1") or Priority 2 ("P2"), as shown in Figure 87 below:

FIGURE 87
LVD HAZARD CODES

Code	Description
P1 – Public Safety	
P1A	Safety Code Violation
P1B	Unusual Public Hazard
P2 – Failures	
P2A	Floating Phase / Neutral
P2B	Broken / Severely Cracked Cross-arm
P2C	Damaged / Cracked Cutout
P2D	Damaged / Cracked Insulators

P2E	Pole: Needing Immediate Replacement
P2F	Faulted Underground Radial Cable or Service
P2G	Overhead or Underground Equipment out of Service
P2H	Streetlights out of Service

P1 failures include problems that require immediate action to repair the damage. This includes threats to public safety, such as downed wires or exposed underground equipment. P1 failures are addressed within 24 hours. Like P1 failures, P2 failures consist of equipment that has actually failed, but P2 failures are less urgent. For example, the Company may find an insulator that has detached from its pin, creating a clearance or public safety hazard. The line would remain energized but no longer in its safe operating condition. At times, the Company may quickly address a P1 failure by reducing it to a P2 failure. For example, the Company may address exposed cables in a fiberglass pad by applying a temporary patch; the P1 emergency-level issue will have been fixed, but the pad is still failed and requires replacement. Typically, the Company works to respond to P2 failures within 14 calendar days. However, this time can extend beyond 14 days, such as when the failed equipment has been bypassed and new equipment is on order for replacement.

Once the Company identifies a failure or damage to the system, it prioritizes its response by categorizing damage by severity as shown in Figure 88 below:

FIGURE 88

Repair Prioritization		
	Timeframe to Address Following Observation	
	Priority 1 – 24 Hours	Priority 2 – 14 Days (Includes weekends)
Criteria	Service restoration, emergency, public safety, or imminent system integrity problem requiring immediate action to correct the situation or damage. Priority 1 defects are imminent failures or present an immediate threat to public safety and are not subject to reclassification.	Damage is believed to be sufficient to cause public safety or system integrity problem if left unattended beyond 14 calendar days.
Example(s)*	A wood pole which is burnt off or broken or energized conductor with less than acceptable clearance.	Cracked crossarm which could fail, a broken down ground that could contact energized conductor, or a loose down guy which could contact energized conductor.

Depending on the nature of the problem, the Company will perform one or more of the following types of service restoration work:

- **Failed Underground Cable** – When a failure occurs on an underground cable, the Company identifies and fixes the fault immediately to restore service to customers. If the underground cable is looped (has feeds from multiple directions), the fault is isolated and service to customers is restored;
- **Failed Distribution Transformer** – These failures are addressed immediately and could warrant further evaluation to determine if the transformer was adequately sized for the load, which in some cases leads to replacement of the existing transformer with a larger one;
- **Car-Pole Accident** – When car-pole accidents result in damage to poles, the Company immediately assigns an available crew to ensure safety of the area, replace the pole, and restring or splice the conductor;
- **Broken Cross-arm, Pin/Insulator, or Pole** – When poles and other components fail, electric service may be interrupted, or public safety might be affected where the wire is left hanging below the required clearance or out of normal operating position. The Company will replace any broken equipment (i.e., a cracked cross-arm); and
- **Failed Overhead Conductor** – When overhead wires fail due to age, deterioration, weather, trees, etc., it typically causes a wire down, which can pose a major public safety hazard. The Company addresses these conditions immediately.

<u>Recent Trends in Service Restoration Work</u>

Service restoration orders have been increasing in recent years. The Company believes that this upward trend is indicative of increasing levels of adverse weather and asset deterioration on the LVD system, which contributes to asset failures and the need for restoration and rehabilitation work. This upward trend is likely to continue in the near-term future as assets are replaced at levels insufficient to keep up with deterioration. The Company's service restoration orders for 2015 through 2020 are shown in Figure 89 below.

FIGURE 89

SERVICE RESTORATION ACTIVITIES 5-YEAR HISTORY

	2015	2016	2017	2018	2019	2020
Service Restoration Orders	18,878	26,807	38,056	31,190	30,300	33,477

The Company developed its forecasted needs for 2021 and 2022 based primarily on historical failures activity, accounting for observed trends. The Company spent at a higher level in this sub-program in 2020 than in other recent years because the Company increased inspection for critical COVID-response locations, particularly hospitals, and therefore invested more to address any anomalies found. Also, there was a catastrophic failure due to a flood in Midland. In 2021 and 2022, the Company expects this situation to revert to historically normal levels, and therefore treats 2020 as an outlier and projected spending in 2021 and 2022 is lower than in 2020. Even accounting for this outlier situation in 2020, the Company's electric distribution system continues to experience increased weather challenges and deterioration, meaning service restoration orders will continue to increase, resulting in higher spending in the service restoration orders investment category over time.

Street Light Failures

In this investment category, the Company replaces failed street light fixtures. Like service restoration, the Company responds to replacing failed street light fixtures as they fail. This spending includes reactive conversion of all failed HID cobra head streetlights to LEDs as the HIDs fail, as discussed in the section of this report on the Company's Streetlighting strategy.

Benefits

This sub-program is essential for the restoration of service to customers for the Company to meet its obligation to serve. Service restoration investment provides a future reliability benefit to customers, by improving the condition of system equipment when failed components are replaced.

ii. LVD Substations Demand Failures

The LVD Substation Demand Failures sub-program addresses damaged or failed LVD substation equipment or components. The capital expenditures in this sub-program include investments in equipment or components, typically replacements, which in some cases also result in capacity and equipment upgrades.

LVD Substations Demand Failure projects generally consist of the following types of investments:

- Replacing damaged or failed equipment/components;
- Replacing damaged or failed structural components; and
- Repairing damaged or failed mobile substations.

As with other Demand Failures sub-programs, spending in this sub-program is projected based on recent historical actual spending. Over the next five years, the Company's projected investment in this sub-program is as follows:

FIGURE 90

LVD SUBSTATIONS DEMAND FAILURES CAPITAL INVESTMENT

5-Year Capital Plan (all values in $ millions)					
Investment Categories	2021	2022	2023	2024	2025
Reclosers	1	1	1	1	1
Regulators	2	2	2	2	2
Transformers	3	3	3	3	3
Other Equipment	1	1	1	1	1
Total	**7**	**7**	**7**	**7**	**7**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Reclosers	26	26	26	26	26
Regulators	78	78	78	78	78
Transformers	6	6	6	6	6
Other Equipment	40	40	40	40	40

Planning Process and Prioritization

The work in this demand failures program is reactive, planned and scheduled after an event has occurred. The Company plans future investment needs based on recent historical actual activity, which has tended to be consistent from year to year in this sub-program. Based on the five years from 2015 through 2019, the Company has experienced approximately six LVD transformer failures (approximately 0.57% of population); 26 recloser failures (approximately 0.51% of population); and 78 regulator failures (approximately 1.52% of population) per year. These historical failure rates are used to project investment needs going forward in this sub-program. The Other Equipment category includes replacement of failed equipment such as blown fuses, lightning arrestors, insulators, switches, and structural components.

The Company is able to promptly address failures to minimize impact on customer minutes by maintaining adequate substation equipment, material inventories, and a mobile substation fleet.

Benefits

This sub-program provides for the level of investment necessary in LVD substations needed to support capital repair or replacement of failed LVD substation equipment to address interruptions and meet the Company's obligation to serve customers.

iii. HVD Lines and Substations Demand Failures

The HVD Lines and Substations Demand Failures sub-program supports the capital replacement of failed 46 kV and 138 kV lines and substation equipment to restore customer service and maintain reliability, through the repair or replacement of HVD lines and substation equipment due to unanticipated failure or very imminent failures (less than 24 hours to failure). Numerous issues can cause these failures, such as lightning strikes, trees, equipment deterioration and car/pole accidents. The Company conducts inspections and evaluation on an ongoing basis, but not all failures can be predicted with certainty. The Company completes the vast majority of projects as quickly as can be scheduled after identifying them, following temporary repairs to quickly restore service to customers. The Company bases projected investment in this sub-program on historical actual spending.

This sub-program historically included the repair or replacement of these same classes of assets that the Company evaluated to be in a state of imminent failure, but those projects have been reclassified to the HVD Lines and Substations Rehabilitation sub-program.

The Company's projected five-year investment plan for this sub-program is as follows:

FIGURE 91

HVD LINES DEMAND FAILURES CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Pole Replacements	1.2	1.2	1.2	1.2	1.2
Pole Top Assembly Replacements	0.5	0.6	0.6	0.6	0.6
Switch Replacements including MOAB	0.2	0.1	0.1	0.1	0.1
Miscellaneous Other Replacements	0.2	0.1	0.1	0.1	0.1
Total	**2.1**	**2.0**	**2.0**	**2.0**	**2.0**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Pole Replacements	58	60	60	60	60
Pole Top Assembly Replacements	87	82	82	82	82
Switch Replacements including MOAB	3	2	2	2	2
Miscellaneous Other Replacements	6	4	4	4	4

FIGURE 92

HVD SUBSTATIONS DEMAND FAILURES CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
Total Spending	2.1	2.1	2.1	2.1	2.1

Pole replacements consist of replacing pole structure(s), including associated pole top hardware. Pole top assembly replacements consist of replacing cross-arms, cross-arm braces, and insulators. Switch replacements, including motor operated air break switches ("MOABS"), are the replacement with an optimally sized switch meeting existing standards. Miscellaneous other replacements may include other capital items such as a span of conductor or lightning arrestor.

MOABS are on/off switches used to automatically sectionalize faulted HVD line sections, to allow the un-faulted sections to be automatically re-energized and able to service customers in the un-faulted section and are a key component of SCADA on the HVD system. When MOABS are installed on an HVD line, they contain a controller that monitors voltage on the line and that communicates with adjacent MOABS through a fiberoptic line. MOABS will sectionalize a line if they detect a loss of voltage, but they do not interrupt the flow of current. These controllers contain cellular modems to enable remote monitoring and operation. The Company is currently in a process of replacing existing MOABS to bring them to current SCADA design standards.

The HVD substation failure investment category supports the replacement of equipment and infrastructure that has failed within an HVD substation, which is included but not limited to power transformers, breakers, capacitors, switches, bushings, station batteries/chargers, regulators, voltage transformers, and facilities (such as fences, gates, and driveways).

a) HVD Lines Demand Failures

Planning Process

The Company determines work needs in this sub-program based on real-time HVD line component failures or very short-term imminent failures (less than 24 hours).

The most urgent HVD line component failures are those resulting in customer outages, making them immediate action items. These are identified by alarms from the SCADA system in the System Control Center, and system operators and/or crews are quickly dispatched to locate the electric fault and restore power to customers. The Company's System Protection Engineering group is often consulted during HVD outage events, using data from substation digital relays to assist in identifying the location of the fault. This fault locating process provides the ability to dispatch crews, often to a line structure within a few spans of the actual fault, reducing patrol time. Calls from customers or other third parties into the customer contact center may also assist in locating the fault if someone saw, heard, or has other insight on the fault location. On rare occasions when a ground patrol cannot locate a fault, a helicopter may be used to assist in patrolling the line. Drones are also available for this purpose. Once the fault location is identified, the Company performs repairs as quickly as safely possible.

Some component failures do not cause a line to trip at all, but they decrease the integrity of the line and usually increase the risk that the line will trip or fail in the future. Examples include floating phases (when a phase wire becomes unsecured from an insulator), broken insulators, broken crossarms, broken poles, or broken static wires. These anomalies are identified through routine annual helicopter patrols, biannual ground patrols (performed on HVD lines which cannot be overflown due to population density or other reasons), or through calls from customers, employees, or other third parties. The Company assigns such component failures a priority and generate orders for the repair or replacement of the component in a time frame consistent with the risk posed, as shown in Figure 93 below. Only actual failures and Priority 1 imminent failures are addressed in this sub-program, with others being addressed in the HVD Lines and Substations Rehabilitation sub-program.

FIGURE 93

HVD SYSTEM PATROL FINDINGS CRITERIA

Priority	Description	Repair Timeline
1*	Imminent Failure	24 hours
2*	Highly Likely Failure	5 to 10 days
3*	Likely Failure	4-6 months
4	Monitor	Repair not required but condition tracked
*SAP repair orders are created for all Priority 1, 2 and 3 findings only		

<u>Inspection Programs</u>

The Company has four key inspection programs to help inform on potential actions to address HVD lines failures.

Pole Inspection Program

It is rare that actual failures or P1 anomalies are identified through the pole inspection program. Refer to the section on the HVD Lines and Substations Rehabilitation sub-program.

Helicopter Inspection Program

The helicopter inspection program (funded through various O&M programs) is a significant source of information to determine immediate action items. For example, a helicopter flight identified a broken brace which caused the cross arm to tilt, resulting in a situation dangerously close to a phase-to-phase flashover, prompting an immediate replacement of the brace to avoid a potential outage to the line and customers.

The Company contracts with a third-party for these patrols, of which there are two types: (1) visual inspections, and (2) visual inspections with the infrared ("IR") or corona camera, shown in Figure 94 below.

FIGURE 94

HELICOPTER INSPECTION

FIGURE 95

HELICOPTER PATROL INSPECTION TYPES

TYPE OF PATROL	***CREW***	***WORK PERFORMED***
VISUAL INSPECTION	Two or three-person crew • Pilot • Observer • Trainer, if observer is not fully trained*	Look for anomalies • Deterioration of/damage to wood pole, cross-arms, and braces • Damage to insulators • Damaged or floating conductors • Forestry concerns • Damage on LVD underbuild • Damages/missing/slack guy wires • Third party concerns • Blown arresters • Evidence of tracking
VISUAL INSPECTIONS W/ INFRARED OR CORONA	Three-person crew • Pilot • Fully trained observer* • Technician to run corona and/or IR camera*	All of the above, plus monitoring equipment detects hot spots or corona signatures on lines
*Trained internal Consumers Energy employee		

A corona/IR camera is mounted to the underside of the helicopter. A technician onboard the helicopter monitors the output of the camera. Infrared inspection detects hot spots on the lines, such as splices and switches, which usually indicate a degraded material or corroded condition that will likely result in failure.

Corona inspections detect ultraviolet emissions on HVD lines, due to ionized air, which is most commonly associated with cracked insulators. These cracks are typically very fine and not easily observed from the helicopter by the naked eye at patrol speed. These fine cracks allow moisture to penetrate the insulator, degrading its effectiveness and can eventually lead to an insulator failure and a line outage. Victor-type grey pin insulators of 1970s–1990s vintage are prone to this type of failure.

Biannual Ground Patrol

For safety reasons, helicopter inspections cannot fly over approximately 400 miles of the HVD system, because it is difficult to land quickly and safely in the event of an emergency. Most of these “no-fly lines” are in urban areas. To inspect these lines, the Company completes ground patrols at least biannually, which includes IR and/or corona inspection using handheld cameras.

MOAB Testing

MOABs allow the Company to sectionalize HVD lines and restore a portion of the customers who would otherwise be affected by a line outage. The controls of the MOABs require power to operate, and since they operate when the line loses power, batteries provide control circuit power. Periodic battery replacement ensures that power is always available to operate the device. MOABs are tested annually to ensure they are in proper working order and the batteries are as needed. During this testing, broken or damaged switches are sometimes identified and replaced under this program.

<u>Project Prioritization and Selection</u>

Projects are prioritized based on real-time failures or anomalies and those discovered through inspection programs. Actions range from simply monitoring to immediate equipment replacement. Engineers and operating personnel take the safety of employees and the public, inspection results, and system operability threats into account to determine the most prudent course of action.

In general, if the HVD line equipment failure or anomaly causes an outage to customers, or its potential failure poses an immediate and intolerable electric system operating condition, it is immediately addressed through this failures program. If the equipment failure or anomaly is not currently causing a customer outage, or its potential failure poses a nominal electric system operability condition, it is addressed it at a future point in time either through the HVD Lines Rehabilitation program or through the HVD Lines Reliability program.

b) HVD Substations Demand Failures

The HVD substations failures investment category includes capital expenditures incurred due to customer outage restoration, and the repair or replacement of HVD substation equipment due to unanticipated or very imminent failure. The mix of projects for any given year will vary greatly depending on a number of criteria including actual failures, risk posed by identified anomalies and number of replacements identified by inspection programs.

<u>Planning Process</u>

Real-time substation component failures or anomalies are key program inputs. Additionally, periodic evaluation of substation equipment allows for identification of equipment near the end of life so that those items can be replaced before they fail and cause an outage to customers or reduces system operability to an intolerable level. Such inspections and proactive replacements are more economical, safer and can save customer outage minutes. Lastly, NERC compliance standards require maintenance on certain components and are another source of input in this program’s planning process.

The cadence of the HVD substation equipment evaluation and inspection is found in Figure 96 below.

FIGURE 96
HVD SUBSTATION INSPECTION CADENCE

HVD Substation Inspection Cadence		
Inspection Task	**Cadence**	**Components Checklist**
All Station Components	Monthly	Visual Inspection
Entire Substation	Annually	Infrared Inspection of entire substation
Protective Relays and Communication Systems	Depends on relay model & failure history	Maintenance & Testing Performed
Station Batteries	Monthly	Voltage Check
	Annually	Equalization
	Annually	Specific Gravity Reading
	4 Years*	Complete Inspection
Power transformers	Annually	Diagnostic Dissolved Gas Analysis of Transformer Oil**
		Periodic combustible gas test/dissolved gas analysis tests
Motor Operated Air Break Switches (MOAB) (decoupled)	Annually	Testing
	4-5 Years	Battery replacement
NERC Circuit Breakers & Switches	Annually	Testing
NERC Current and Voltage Sensing Devices	10 Years	Inspection
*Or periodically based on battery condition once battery reaches 15+ years in age **For Power transformers with Load Tap Changers Only		

Project Prioritization and Selection

The Company takes action based on real time failures and anomalies, and issues discovered through the inspection process, which includes:

- **Infrared inspections** – 100% (one-year cycle) of HVD substations and 50% (two-year cycle) of LVD substations are inspected annually. Tests are scheduled and results are captured in the Cascade substation asset management program. Identified anomalies are assigned a priority (1 through 4) based on a point system that takes into account the type of substation (HVD, single transformer LVD, multiple transformer LVD, or strategic customer), recorded maximum circuit amps in the past two years, temperature rise above similar equipment, wind speed, and type of equipment. Priority 1 signatures require an action plan to be in place within two working days and may be covered under this program. Priority 2 anomalies require an action plan within 30 days, Priority 3 within three months and Priority 4 within one year. Priority 2-4 anomalies are covered under the HVD Substation Rehabilitation program.

- **Dissolved Gas Analysis ("DGA")** – HVD transformers are tested on a two-year cycle; all Load Tap Changer (LTC) transformers are tested on a one-year cycle; LVD transformers are tested on a six-year cycle. Demand tests are completed on a more frequent basis if analysis quality is trending to indicate an issue or imminent failure. Samples are tested for multiple gasses including ethane, ethylene, methane, and acetylene. Results are then fed into a software program called TOA4, from Delta-X Research. The software identifies the type of issues the transformer is experiencing (based upon the mix of gasses) with a high degree of accuracy and assigns a priority code to the sample. TOA4 results are stored in Cascade. Priority 4 samples are categorized as imminent failure and may be scheduled for replacement under this program.
- **Sulfur hexafluoride ("SF_6") inspections** – Gas quality testing is on a three-year test cycle. Some demand tests are completed annually if the gas quality is trending to indicate failure. Gas in SF_6 breakers is tested for moisture content, SO_2 content and gas purity by the Field Technical Services group. Breakers with results outside the minimum standard for SO_2 or gas purity are typically tabbed for replacement under the HVD Substation Rehabilitation program. Breakers with high moisture content are scheduled for a gas drying procedure under the HVD Substation O&M demand program.

All the above methods have proven over time to be effective in identifying the imminent failure of equipment, resulting in a proactive action such as replacement and significant SAIDI savings.

For some HVD substation equipment (switches, voltage transformers, current transformers, and capacitor banks), this program is primarily reactionary, replacing equipment that has failed. Inspection programs for this equipment have been recently reinstated but it will take several years to work through the backlog in this area. Some imminent failures are identified through monthly visual patrols and may be replaced through this program prior to failure. Some equipment (transformers, station batteries, gas circuit breakers, and transformer bushings) are monitored and may be replaced prior to failure through this program.

<u>Timing</u>

In general, if an HVD substation equipment anomaly is causing an outage to customers or if its potential failure poses an immediate and intolerable electric system operating condition, it will be addressed immediately through this sub-program. If the equipment anomaly is not currently causing a customer outage or its potential failure poses a nominal electric system operating condition, it will be addressed at a future point in time through the HVD Lines and Substation Rehabilitation sub-program, or alternatively through the Reliability Program. Some projects, such as HVD transformer replacements with longer lead times, may be delayed if other replacements are identified that are determined to have a higher risk of failure or have failed in service.

Benefits

This sub-program is essential, as it is utilized to either restore service to customers or address an imminent failure condition that could result in either an outage to customers or create an unacceptable system operating condition.

For instances of imminent failure, this program has a positive impact on reliability, by the identification and replacement of failing transformers and SF_6 breakers prior to failure. Such replacements prior to failure also have definite impact on safety, reliability, resiliency, and control of the system. Replacement of failed equipment as quickly as possible following failure has a lesser but still significant impact on all these metrics.

iv. LVD Metering Demand Failures

The LVD Metering Demand Failures sub-program consists of capital expenditures for meters purchased that are allocated to the Demand Failures Program. See the description of the LVD Metering New Business sub-program for additional details.

v. LVD Transformers Demand Failures

The LVD Transformers Demand Failures sub-program consists of capital expenditures for transformers purchased that are allocated to the Demand Failures Program. See the description of the LVD Transformers New Business sub-program for additional details.

vi. Center Suspension Streetlight Conversion

As discussed in the Evolution of Streetlighting Strategy section of this report, the Company plans to convert its center suspension streetlights over the next several years. The Company's planned investment in this sub-program are as follows:

FIGURE 97

CENTER SUSPENSION STREETLIGHT CONVERSION CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Projects	2021	2022	2023	2024	2025
Center Suspension Conversions	1.3	3	5	5	10
Total	**1.3**	**3**	**5**	**5**	**10**

vii. Metro Demand Failures

The Metro Demand Failures sub-program involves the replacement of failed cables, transformers, and civil infrastructure within the Company's Metro systems. Historically, the Metro Demand Failures sub-program also included work to repair or replace equipment that the Company determined to be at risk of imminent failure, but that work is now included in the new Metro Rehabilitation sub-program. Metro Demand Failures costs are highly dependent many factors including on contractor labor costs, and are therefore particularly variable, fluctuating based on contractor workload levels. The Company projects its needed investment level in this sub-program based on historical averages and trends.

The Company's five-year investment plan for this sub-program, which addresses failures of cables, transformers, and civil infrastructure, is as follows:

FIGURE 98

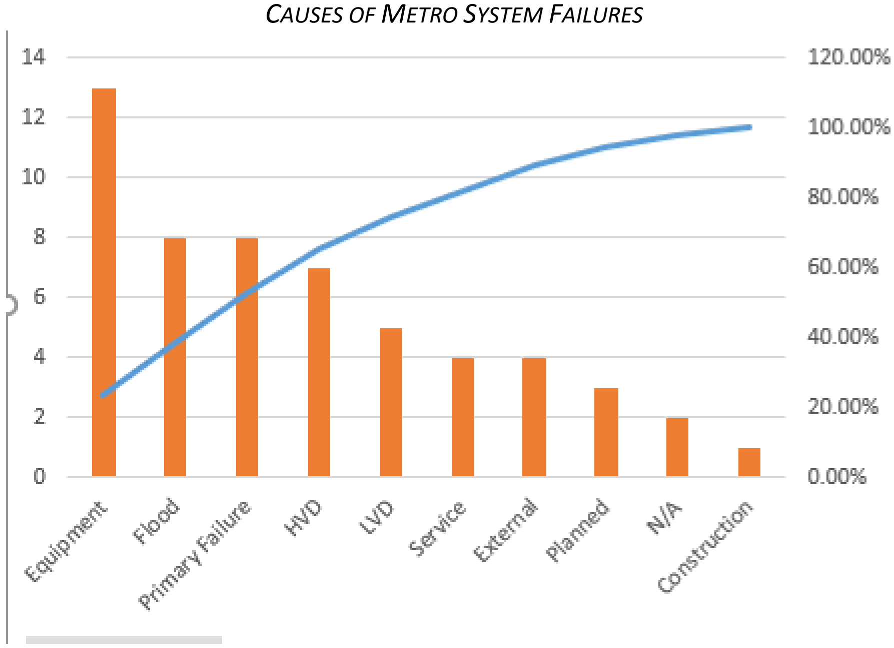
METRO DEMAND FAILURES CAPITAL INVESTMENTS

5-Year Capital Plan (*all values in $ millions*)					
Investment Categories	2021	2022	2023	2024	2025
Cable Failures and Replacements	0.7	0.6	0.6	0.6	0.6
Transformer Failures and Replacements	0.1	0.2	0.4	0.4	0.4
Civil Infrastructure Failures and Replacements	0.3	0.3	0.1	0.1	0.1
Total	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**

Many factors contribute to deterioration of the cabling, equipment, and civil infrastructure in the Metro systems, including age of the system, weather, and wear. Figure 99 shows the most common causes of failures on the Metro system.

FIGURE 99

CAUSES OF METRO SYSTEM FAILURES



- Equipment failures: Common equipment failures are transformers, SF_6 gas switches, and mis-operation of molded vacuum interrupters;
- Flooding: Flooding of vaults and manholes due to weather events of heavy rain or multiple sustained days of rain; and
- Primary cable failure: Many IPLC type cables fault and fail due to age of the asset.

Illustrations of some specific Metro failures are shown in the figures below.

FIGURE 100
DAMAGED CABLE

FIGURE 101
DAMAGED / CRUSHED DUCT BANKS

FIGURE 102
DETERIORATED MANHOLE/VAULT ROOFS


(Left – Concrete material falling from the Roof; Right – Crack in Concrete Roof Structure)

FIGURE 103
SUNKEN/DETERIORATED MANHOLE ACCESS

FIGURE 104
RUSTED/DETERIORATED VAULT HATCHES AND VENTS

Planning Process

Electrical assets in Metro vaults may fail due to age, deterioration, standing water, and runoff contaminants (e.g., salt). The most common electrical assets that fail are Metro transformers, primary cable, and secondary cable. If a primary cable fails, the Company identifies potential switching schemes to immediately restore service to customers. After the fault is isolated and customers are restored, there are times that the Metro system is no longer in an open looped configuration (i.e., no longer has feeds from multiple directions) and needs to be repaired. A design will be created for permanent repairs. By leaving this faulted section isolated for a long period of time, there would no longer be a way to restore service to customers from that direction. If a transformer fails, it is replaced with a spare unit. If a secondary cable fails, a new cable is pulled in a spare conduit adjacent to the failed cable. The failed cable is cut at both ends and removed, creating another spare conduit. Transformer failures typically require the failed transformer to be immediately removed and replaced with a spare unit kept that the local headquarters.

Benefits

Upgrading and replacing degraded components in the Metro system allows the Company to maintain a redundant system in the downtown areas of cities, providing a reliability benefit. This benefit directly impacts courthouses, jails, municipal offices, police, and fire departments, as well as many businesses and residents. A Metro system in good condition allows employees and contractors to work in a safe environment and supports public safety. Investing in the Metro system to alleviate failure conditions allows customers not to be single-sourced when manholes and vaults are isolated for repair.

D. Asset Relocations Program

The Asset Relocations Program includes capital investments to relocate electric assets to accommodate road, building, and other third-party construction projects, as well as internal Company projects. The cost of relocating lines in the road ROW, and in some cases on private property, is typically the responsibility of the Company.

Most Asset Relocations work is entirely "unplanned," in that it is reactive to requests from third parties external to the Company.

i. LVD Asset Relocations

The LVD Asset Relocations sub-program responds to internal and external requests to relocate LVD lines. This sub-program also includes "make ready" work to prepare LVD poles for third-party attachments; make ready work can include physical relocation of a pole, but it may also include work to strengthen a pole to allow it to support additional weight. State and municipal agencies, private property owners, and other Consumers Energy departments make requests for relocations; in addition, telecommunications companies request make-ready work so they can attach phone and cable lines and cellular equipment on poles. The sub-program includes any reimbursements from the requesting party, which directly offset expenses incurred to perform the work.

Due to the demand-based nature of this sub-program, the Company does not follow a specific planning cycle, and generally cannot plan relocation projects far in advance. Each request contains different timelines and requirements based on the nature of the request, and the Company constantly adjusts timing of projects to meet customer schedules. The Company projects its spending levels based on historical activity, while also accounting for observed trends, particularly related to economic activity. The Company's five-year investment plan for this sub-program, based on costs to relocate assets less any reimbursements received, is as follows:

FIGURE 105

LVD ASSET RELOCATIONS CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Third-Party Requested Relocations	20.8	21.9	22.9	24.0	25.0
Relocating LVD Underbuild on HVD Poles	14.0	14.7	15.3	16.0	16.7
Make-Ready Work	14.1	16.0	17.3	18.7	20.0
Total	**48.9**	**52.5**	**55.6**	**58.8**	**61.7**

Planning Process

The activity in this sub-program is entirely driven by requests from both external and internal stakeholders. For all project requests, a party submits a request that includes timelines for completion if applicable, the project purpose, contact information, and any other pertinent information. For many municipal projects and large internal projects, the Company holds site meetings to gather further information.

The Company studies the descriptions, maps, surveys, designs, and/or other documentation provided by the requester and combines that documentation with internal maps and field measurements to determine what Company facilities, if any, require relocation and where assets should be relocated.

For requests requiring significant relocation or changes to the LVD system, the Company evaluates the proposed changes against a load flow analysis and reliability assessment to determine if relocation will have an adverse effect on the system. If a proposed relocation will negatively impact the reliability or capacity of the LVD system, changes would be necessary. For example, a customer could request relocation of facilities to the edge of their property line, but that move could put the facilities in dense vegetation, making the line less accessible and requiring more line clearing. In that case, the Company would work with the customer to find a better route that meets the customer's needs without impeding reliability. However, if the relocation significantly changes the length of conductor, it may create a capacity issue and the conductor would need to be upgraded in size.

Third-Party Requested Relocations

Third-party requests come from both private property owners and from government agencies.

Government agency requested LVD relocations can fluctuate throughout the year for many types of projects, such as road and bridge widening or improvements, repairs to municipal facilities, and streetlight and traffic signal modifications. Road and bridge widening or improvement projects require the Company to move poles, wires, and other LVD equipment due to changes to the road location and grade and to provide proper clearance for any large equipment that the road construction contractors have onsite.

Government agency timelines can vary widely. Municipalities may request work on an almost immediate basis, such as moving a pole for a water main break repair. They may also request work years in advance as the projects increase in size and complexity. Repairs to municipal facilities such as sewer or water lines may require the Company to temporarily move or remove facilities such as poles and transformers or underground equipment. Other times, the modification may be permanent. Agencies request these relocations to provide access to their facilities without having to work around LVD infrastructure or risk violating clearance requirements.

Examples of the municipality designs for these relocations are shown in the figures below. Figure 106 is a road widening project that involves moving poles and streetlights. Figure 107 is a road widening project that involves relocating traffic signals.

FIGURE 106

LVD POLE AND LIGHT RELOCATION DIAGRAM FOR MUNICIPALITY ROAD WIDENING

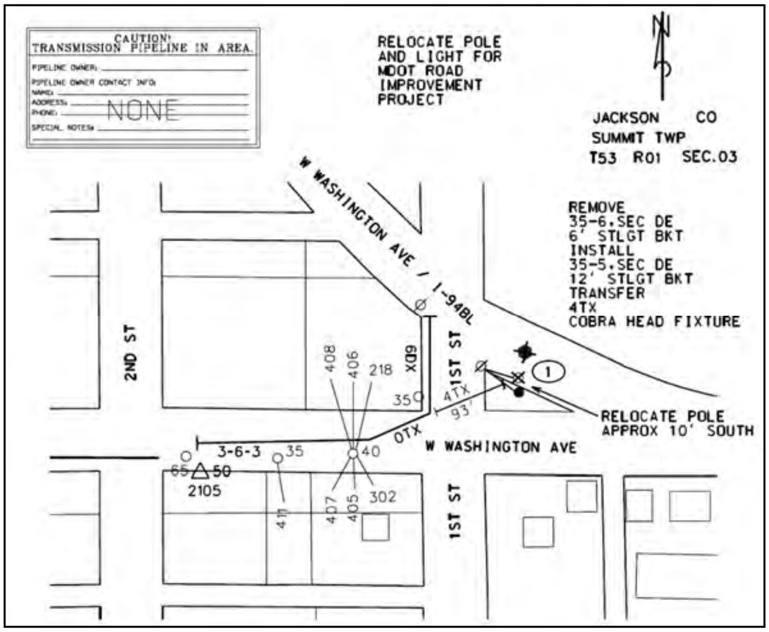
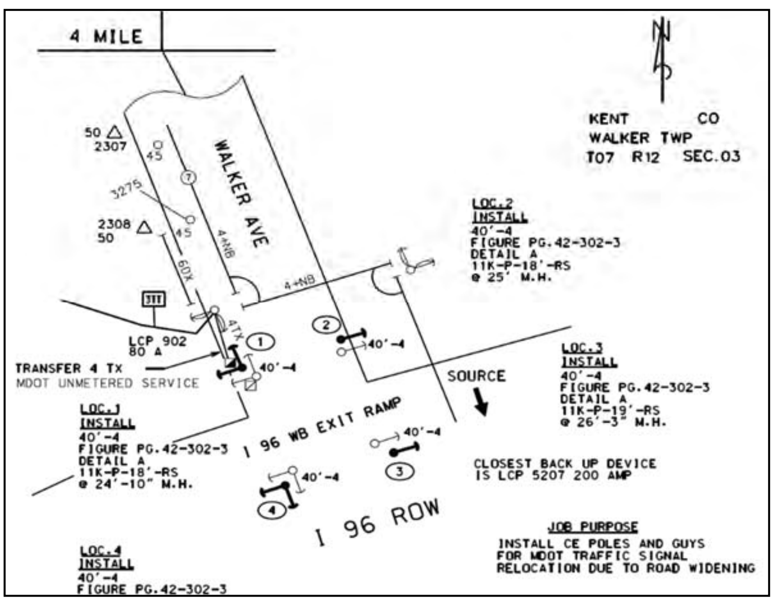


FIGURE 107

LVD TRAFFIC SIGNAL RELOCATION DIAGRAM FOR MUNICIPALITY ROAD WIDENING

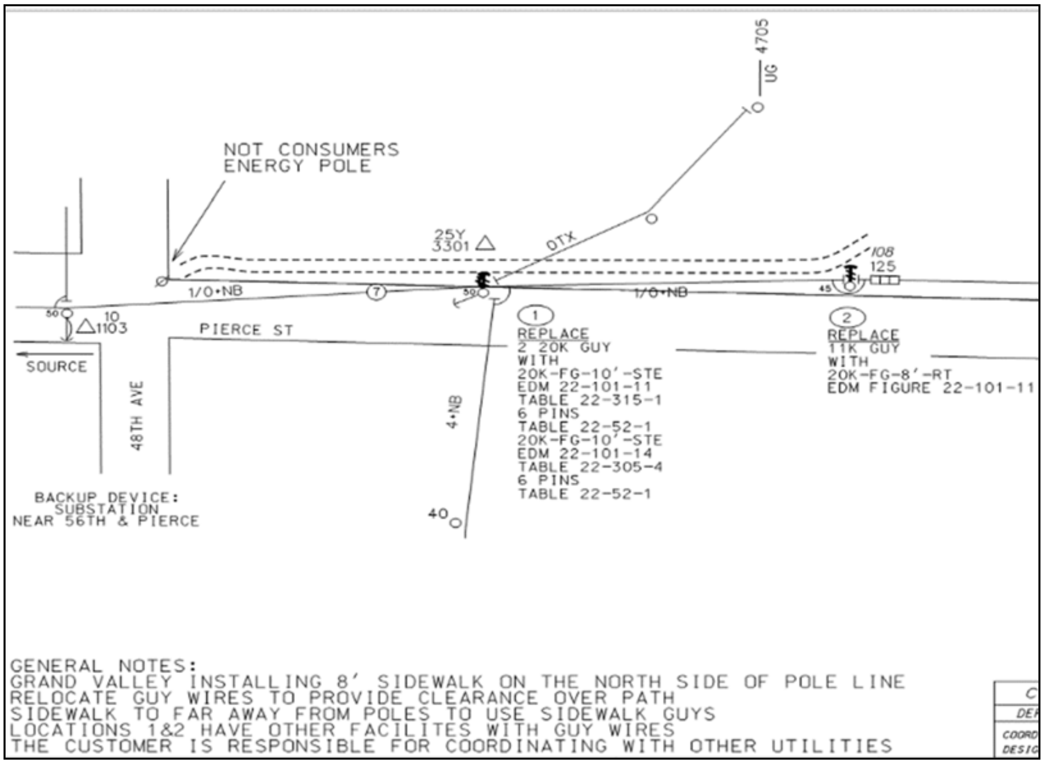


Private property owner requests vary widely based on the type of project and project timeline. Property owners request LVD relocations for building additions, logistics, landscaping, or other construction projects. Private landowners often request relocation of overhead lines out to the road or underground, particularly to facilitate moving large farm equipment. Residential customers often request relocation of

LVD lines to facilitate building an addition, pool, shed, barn, or landscaping feature such as a pond or berm. Commercial customers often request relocation of poles from a parking lot or other area.

Figure 108 below shows an example of a private landowner request for relocation due to an addition of a sidewalk.

FIGURE 108
LVD ASSET RELOCATION FOR PRIVATE LANDOWNER



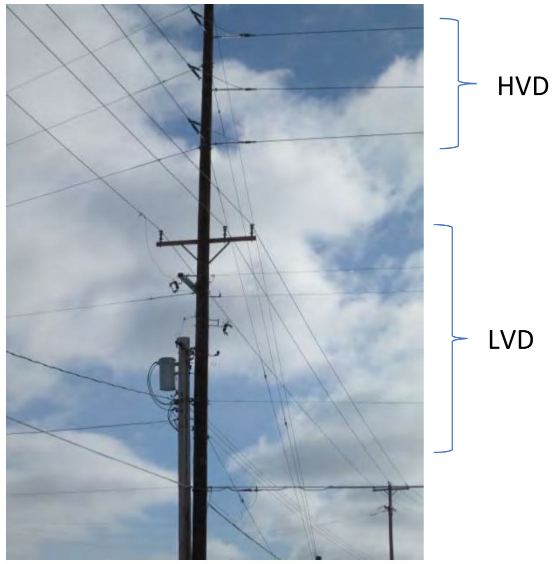
Requests within the Company

Relocation requests within the Company may come from the HVD Planning group, the Substation Planning group, or the Metro Planning group, in order to facilitate projects planned by their respective groups. The majority of the requests within the Company consist primarily of requests to relocate LVD underbuild on HVD poles. LVD underbuild refers LVD assets that are attached to an HVD pole under the HVD distribution lines.

When there are LVD facilities attached to HVD poles that are being replaced or relocated (known as "underbuilt"), it requires a transfer of the LVD assets to the new HVD pole (refer to Figure 109 below). Typically, these internal requests are scheduled to take place during off-peak months, particularly during the winter, to allow work to be completed outside of the summer peak load season when air conditioners and other cooling systems create high energy demand. This ensures the LVD infrastructure can accommodate load transfers from one circuit to another.

FIGURE 109

UNDERBUILD LVD WIRE ON HVD POLE



While relocations of LVD underbuild are the primary component of internally requested LVD relocations, requests may also come from Substation Planning or Metro Planning.

- Substation Planning may request a relocation to complete work on a substation, such installing equipment or changing the LVD system to handle a load transfer or mobile substation set, either planned or on an emergent basis. The LVD relocation work could include installing new switches outside of the substation fence, relocating poles, or adding new poles and wire for the mobile substation. At times, property ownership constraints limit the use of a mobile substation, requiring HVD and LVD infrastructure changes to either make room for a mobile substation or to allow a mobile substation at a location relatively close to, but not on the same site as, the permanent substation.
- As the Metro system ages and vault conditions deteriorate, the Company may relocate parts of the Metro system to a direct-bury LVD system (similar to those found in underground platted subdivisions). In Figure **110** below, the picture on the left represents typical padmounted equipment. The picture on the right illustrates a vault with structural damage that could be replaced with a direct bury. Converting to direct buried LVD offers a couple advantages:
    - The cost for replacing and reconstructing a vault is very high, because it requires just as much civil engineering work (walls, foundation, roof, etc.), if not more, than electrical work. Many vaults have covers in parking lots and roadways, making them susceptible to heavy traffic, water, salt, and other road contaminants, causing them to break down and threaten vehicle and pedestrian traffic; and
    - If an outage occurs on the Metro system, the time to repair the fault is longer due to the accessibility of the Metro system components.

FIGURE 110

DIRECT BURY SYSTEM (LEFT), VAULT WITH STRUCTURAL DAMAGE (RIGHT)

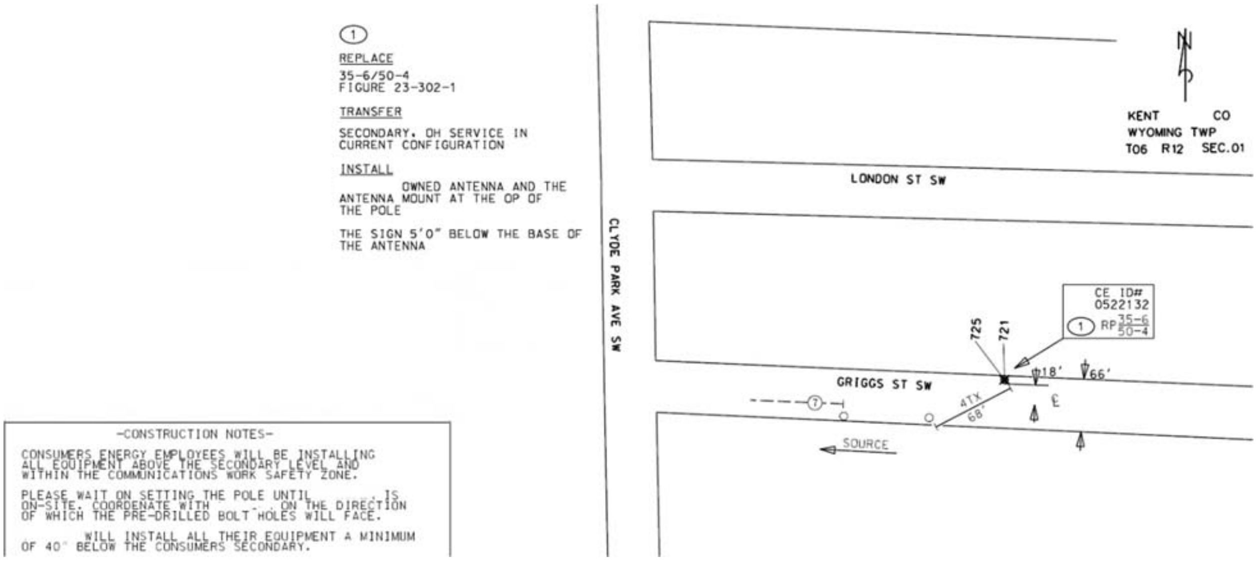
Make-Ready Work

Make-ready work is initiated through the Company's pole attachment permitting process after an applicant, typically a communications company, requests to place new attachments or modify existing attachments on Company poles. The scope of make-ready work for each application is determined by field measurements and engineering analysis of existing conditions with the applicant's proposed attachment characteristics, which is evaluated to meet National Electric Safety Code ("NESC") requirements. Make-ready work can include a range of construction activities, including but not limited to raising electric conductors and equipment, adding, or manipulating down guys, effectively grounding streetlight brackets, raising or lowering existing communications attachments, and pole replacements.

Attachment types are typically wireline/fiber and wireless antennas. However, attachments can also include municipal banner or other utility or municipality electric attachments. The volume of work can vary widely over time, depending on how other parties build out their systems or attachments. Assuming the Company has an established pole attachment agreement in place with the attaching party, the party submits an application, and the Company performs an engineering evaluation. After the engineering analysis is completed, the Company plans a make-ready project to either create physical space on a pole and/or strengthen the pole to support the new attachment, as well as bring the structure to present NESC requirements.

Figure **111** below shows an example of a make-ready project design. In this case, a pole replacement was required to create the necessary space and height to support a 5G antenna. A cost estimate was provided to the attaching party, who agreed to pay. The pole will be replaced to allow attaching the antenna to the pole top.

FIGURE 111
EXAMPLE OF MAKE-READY DESIGN



<u>Recent Trends in LVD Asset Relocations</u>

The Company saw a marked increase in requests for make-ready projects starting in the summer of 2018, causing spending on such projects to increase substantially going forward from that point, a trend which has continued through 2019 and 2020. Additionally, the Company needed to relocate an increasing number of LVD lines starting in 2019 to accommodate increasing amounts of HVD reliability projects, particularly in locations where LVD lines are underbuilt on HVD structures.

The Company is projecting that make-ready work will remain at elevated levels compared to historical averages, especially as telecommunications companies install 5G cellular equipment on poles. The Company also anticipates a continued need in LVD lines that need to be relocated to accommodate HVD projects as the Company increases its work on the HVD system, especially in the HVD Lines Reliability and HVD Lines Rehabilitation sub-programs. In addition, the Company has been experiencing a steady increase in third-party requests, with a 14% annual increase in expenditures to relocated overhead and underground lines and services for customer-driven projects. The Company expects this trend to continue, driving growth in this sub-program.

<u>Benefits</u>

This sub-program primarily functions to serve customer requests, whether they are internal or external. However, every time old or obsolete equipment is replaced through this sub-program, reliability improves because of the new equipment and the latest standards implemented at the time. Relocations performed for HVD or substation work allow maintenance work on the facilities before a failure causes an outage. Preventatively preparing the LVD system for this work can save many customer outage minutes, as an outage would typically de-energize more than one circuit on these systems, with an average of 1,000 customers per circuit, for three hours or more. When LVD projects can support a planned load transfer for HVD and substation work, the Company can perform the work in a controlled environment with little or no outage to customers. Additionally, as mentioned above, some relocation requests provide clearance for large equipment like farm machinery and road construction equipment. Without sufficient clearance, that machinery may contact the LVD system, causing an outage, putting the operator or other members of the public in danger, and causing thousands of dollars of damage. The LVD Lines Relocation sub-program ensures that municipal requests are completed by the deadline. Ultimately, if the Company does not complete LVD Lines Relocation work for any reason, it could face legal consequences and reputational damage.

ii. HVD Asset Relocations

The HVD Asset Relocations sub-program includes the capital investments necessary to facilitate non-reimbursable relocations of 46 kV and 138 kV lines required to accommodate usage of public ROW and required transmission project work. The cost of relocating lines in road ROW, or in some instances on private property, is typically the responsibility of the Company. In other cases, such as relocation work requested by businesses and residential customers, the requesting party will pre-pay or reimburse the Company for the cost of the relocation, but the transactions will still pass through this sub-program.

Projected investment for this program is based on historical averages, and the Company projects to invest $900,000 per year during each of the next five years. Due to the nature of the work, most projects supported by this program are unknown at the start of the year.

Planning Process

Like the LVD Asset Relocation sub-program, the activity in this sub-program is primarily entirely driven by requests from outside of the Company. Depending on circumstances, the Company may have some input on timing or sequencing the work.

There are four general categories of parties that may request HVD Asset Relocations projects: municipalities and other government agencies, transmission owners, private landowners, and internal Company departments.

Municipalities and other government agencies request HVD Asset Relocations to facilitate their civil engineering projects, such as road and bridge widening and improvements; repairs to municipal facilities; work on water and sewer lines; and streetlight and traffic signal modifications. The HVD Asset Relocations allow those agencies to access their facilities without having to work around HVD infrastructure. Relocations may be temporary or permanent.

Michigan Electric Transmission Company (“METC”) or another transmission owner may request HVD Asset Relocations to accommodate their transmission projects. For example, the Company may have HVD lines that are attached to METC structures below transmission lines. Depending on the nature of the project, METC may reimburse the Company for associated costs. This is handled on a case-by-case basis.

Private landowners and businesses request HVD Asset Relocations to accommodate additions, landscaping, and other construction projects on their property. One relatively common request is for overhead lines to be repositioned to allow for building additions.

Internal Company departments may require HVD Asset Relocations to accommodate their own projects that they are planning.

Benefits

Although the primary purpose of this sub-program is to accommodate the needs of customers and other external parties, the sub-program also helps improve reliability through the installation of new equipment. When the Company replaces old or obsolete equipment with new equipment as part of a relocation project, reliability is improved since the new equipment has up-to-date design standards and less general wear and tear.

iii. Metro Asset Relocations

The Metro Asset Relocations sub-program responds to both internal and external requests to relocate subterranean civil and subterranean or pad mounted electric facilities, and/or adjust manhole chimneys and castings due to road grade changes, either in public ROWs or on private property, that are part of the Company's Metro system in core urban areas. The Company generally treats externally requested Metro relocation projects – typically "coordination of utilities" projects championed by local and state government agencies – on a demand basis, with the Company making it a priority to meet mutually agreed upon deadlines and milestones, and to perform the required work within the requested ROW. With requests to move existing overhead electric facilities underground in and around the fringes of the established Metro system, if it is not possible to directly bury the assets in a private easement, the Company has provided customers with cost estimates for Metro infrastructure in accordance with Tariff Rule C1.6. Internally requested projects, requested by other departments within the Company, may be planned further in advance, rather than on a demand basis.

Because much of the sub-program is demand-based, the Company's spending in the Metro Asset Relocations sub-program due to external requests typically rises and falls in correlation with Michigan's overall economic health. Metro Asset Relocations is therefore challenging to forecast, because it is contingent on state agencies and municipalities contacting the Company in advance of the desired date of a coordination of utilities project, and the municipality providing the required information and their portion of work to coincide with their desired date(s). The Company therefore uses analysis of historical trends and data to make yearly spending projections and as a basis for future investment plans. The Company plans this sub-program conservatively by starting with a historic average baseline and then reevaluates and adjusts investment levels up or down from that baseline as projects and commitment levels become firm. The Company's five-year investment plan for this sub-program is as follows:

FIGURE 112

METRO ASSET RELOCATIONS CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
BCK – Jackson St Parking Lot		1.0	0.4		
FLT – Saginaw Street		2.0	0.25		
GR – N Division Street			1.75	1.4	

Other Projects	3.9	1.0	2.0	3.0	4.4
Total Investment	**3.9**	**4.0**	**4.4**	**4.4**	**4.4**

Planning Process

External relocation requests come from state agencies, municipalities, and private developers. State agencies and municipalities may request relocations to accommodate for upcoming civic improvement work for a specific ROW. Typical improvements include storm and sanitary sewers, water mains, street improvements, and streetscapes. Municipalities, Downtown Development Authorities, Tax Increment Finance Authorities, and private developers may request relocations to convert overhead electric systems to subgrade civil and electrical systems, generally to improve aesthetics. These requests typically require the customer to provide a non-refundable engineering deposit for the Company to perform a feasibility study to find an underground path for the civil infrastructure system.

Projects triggered by an internal request are considered during the Metro planning process, which takes place each year. Company engineering planners with responsibility for planning and design of the affected Metro system area prepare scope documents and estimated project costs during this process. Metro planners also meet with their municipal colleagues each year to discuss their workplans and discuss opportunities for coordination of utilities projects.

If either demand or planned projects require new or modified civil infrastructure, they are submitted to a contracted civil engineering firm to create a feasibility study for a new civil infrastructure path. The feasibility study will include several options for possible routes and estimated construction costs for those options. The Company will review the feasibility study to assess the ease of construction and impacts to future electric operations and communicate the selected option to the civil engineering firm, who will then prepare a civil design. The civil engineering firm will deliver the design, along with documents needed to obtain permits from the relevant municipality or government agency to perform work in the ROW, including a detailed traffic control plan.

Examples

Recently, MDOT's Department of Rail developed a project to replace two railroad bridges in downtown Jackson. The Department of Rail's proposal for new bridge footings conflicted with the Company's high capacity Metro duct and electrical cables that provide electric to roughly one-third of downtown Jackson. The Company worked with the Department of Rail to facilitate replacing the electric duct bank with a steel casing at a depth that would allow for the successful construction of the new bridge footings to be built above the casing. Figure 113 provides pictures of this work.

FIGURE 113
DOWNTOWN JACKSON RAILROAD BRIDGE METRO RELOCATION PROJECT

Looking ahead to 2022 and 2023, the Company has already identified three Metro Asset Relocations projects:

- City of Battle Creek: West Jackson Street parking lot reconstruction;
- City of Flint: Saginaw Street reconstruction; and
- City of Grand Rapids: North Division Street.

All projects will be coordinated with the respective cities' engineering departments. In Battle Creek, the Company will be installing new Metro infrastructure to replace older and undersized civil facilities and prepare the civil system for redevelopment of empty storefronts to future mixed-use developments proposed by Battle Creek Unlimited prior to the final parking lot reconstruction.

In Flint, the Company is replacing its older and undersized civil facilities in the Saginaw Street ROW in coordination with the City's major reconstruction of the historic brick street.

In Grand Rapids, the Company had planned to rebuild the civil infrastructure in 2020 but was asked by the city to defer this work to coordinate with a city project to replace the water main, streetlight infrastructure, and streetscape. The Company agreed to this change, deferring the project to 2023 and 2024.

Coordinating replacements at all three locations with the respective municipalities lowers restoration costs and increases customer value once the projects are complete. The Company's projected spending is based primarily on historical spending and observed trends.

Benefits

Although the primary purpose of this sub-program is to accommodate the needs of customers and other external parties, the sub-program also helps improve reliability through the installation of new equipment. When the Company replaces old or obsolete equipment with new equipment as part of a relocation project, reliability is improved because the new equipment has up-to-date design standards and less general wear and tear.

E. Reliability Program

The purpose of the Reliability Program is to ensure the long-term safe and reliable operation of the electric distribution system, particularly by reducing system outages and hardening the system. Capital expenditures in the Reliability Program include investments to install, upgrade, and rehabilitate LVD and HVD lines, LVD and HVD substations, Metro underground assets, and protective relay systems. The Reliability Program also includes capital expenditures to modernize the electric grid, including investments in grid infrastructure improvements (i.e., Grid Modernization) and battery storage.

Reliability Program investments are a major contributor to the Company's efforts to address deteriorated assets; while other programs may replace deteriorated assets as a secondary consideration, many Reliability investments have the express purpose of doing so. Many Reliability Program investments are also tied to the Company's SAIDI improvement glidepath. Over the next five years, the Company plans to increase its investments in the Reliability Program in order to reduce system deterioration and to bring the SAIDI improvement glidepath to reality.

The Company's Grid Modernization investments are included in the Reliability Program because many of the automation capabilities that are delivered by these devices improve reliability for customers. Grid Modernization investments also include the Company's efforts to build its distribution system for the future, as described earlier in this report in the section on the Grid Modernization Roadmap.

Some spending in the Reliability Program was historically included in the Demand Failures Program, as it addresses "imminent failures." Since 2020, all such "imminent failure" spending has been reclassified as Reliability Program spending, essentially entirely into the Rehabilitation sub-programs that were not yet defined when the 2018 EDIIP was filed. In the Rehabilitation sub-programs, it is the nature of some investment categories that the investments therein cannot be responsibly planned months in advance; once an anomaly is identified, it must be promptly addressed to prevent a failure. Spending in these few investment categories in the HVD Lines and Substations Rehabilitation sub-program is more analogous to spending in the Demand Failures Program, responding quickly to urgent issues as they are identified. The only real difference is that Demand Failures projects respond to failures that have already happened, whereas these "emergent" Rehabilitation projects respond to failures that are *about* to happen. In these "emergent" Rehabilitation areas, the Company considers recent historical spending to project future investment needs, in a similar manner to Demand Failures.

Additional details for each of the individual sub-programs can be found below.

i. LVD Lines Reliability

The LVD Lines Reliability sub-program includes projects to ensure the long-term safe and reliable operation of the Company's LVD lines. The sub-program includes a diverse range of projects that are specifically designed to address concerns on a given circuit or circuits and either reduce customer outage frequency (SAIFI), reduce the number of emerging repetitive outage customers (CEMI), and/or reduce customer outage durations (CAIDI and SAIDI). The LVD Lines Reliability sub-program consists of four investment categories: (i) targeted circuit improvements; (ii) pole replacements; (iii) circuit exit enhancements; and (iv) ROW and easement acquisition projects.

The Company's current five-year plan includes a large increase in the amount of targeted zone improvement work; this increase forms a cornerstone of the Company's efforts to reduce system deterioration and improve performance by targeting those areas of the LVD system that will most drive improvements. The plan also includes steady replacement of our LVD poles, as a steady replacement rate will balance customer benefit with the rejection rate, as discussed more below.

The Company's five-year plan for this sub-program is as follows:

FIGURE 114

LVD LINES RELIABILITY CAPITAL INVESTMENTS

5-Year Capital Plan (*all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Poles replaced due to inspection	13.6	13.8	14.2	14.5	14.6
Targeted circuit improvements	23.2	26.5	60.2	65.7	73.6
Circuit exit enhancements	0.6	1.3	2.0	2.2	2.2
ROW and easement acquisition	3.2	4.2	4.4	4.5	4.6
Total	**40.7**	**45.9**	**80.8**	**86.9**	**95.1**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Poles replaced due to inspection	1,100	1,526	1,300	1,300	1,300
Targeted circuit improvements	100	103	262	282	315

Circuit exit enhancements	23	80	51	54	54

The sections below describe each of the LVD Lines Reliability investment categories.

Poles Replaced Due to Inspection

Pole replacements in the LVD Lines Reliability sub-program are completed in response to prior inspection results that identified poles at risk of failure. The Company evaluates the results of those pole inspections to determine if a simple pole replacement is required, and further evaluates inspection results to determine if an entire pole line should be replaced or relocated to improve reliability.

Historically, the Company targeted a higher number of annual pole replacements in this investment category. However, after evaluating historical data, the Company determined that targeted circuit improvements deliver greater reliability benefits for customers. Over the period from 2015 through 2019, LVD pole failures contributed an average of 3 SAIDI minutes per year, excluding MEDs, which represents approximately 1.5% of SAIDI minutes over that period. Correspondingly, the Company plans to maintain a steady replacement rate for LVD poles in this investment category, but not pursue a larger ramp-up of investment because increased investment in targeted circuit improvements will yield higher value for customers. Note that LVD poles may be replaced in other sub-programs and investment categories, including the targeted circuit improvement investment category in this sub-program.

Targeted Circuit Improvements

Targeted circuit improvements include several project types with customized solutions to address specific reliability concerns. The most common strategies employed are: (i) reducing the amount of non-standard voltage on the distribution system; (ii) first zone interruption reduction; and (iii) zonal targeted investments.

- Non-standard voltage reduction: The Company converts distribution circuits and substations energized at non-standard voltages to the three standard operating voltages that Consumers Energy operates. The Company currently operates 13 general distribution voltage systems; the three standard operating voltages are 4.8/8.32kV, 7.2/12.47kV, and 14.4/24.9kV grounded-wye. Customer-dedicated systems are not within the scope of this category. The benefits of converting the non-standard systems to the three standard operating voltages are:
    - **Safer operating systems** – Grounded-wye operating systems are safer to operate than non-standard Delta systems. Delta systems require two-phase ground faults to be present before the phase protective device operates/trips, which means a downed Delta wire will not trip a primary protective device until a second phase fault develops;
    - **Reduced system losses and increased system line capacity** – Converting Delta systems to grounded-wye reduces load current on primary lines, thereby increasing available line capacity. For the same electric load, the grounded-wye system will carry 58% of the load current that the Delta system carries (e.g., a 400

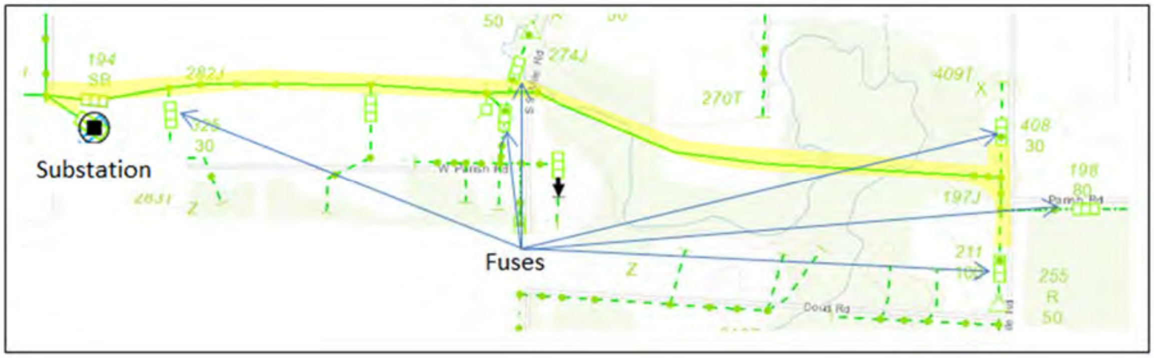
Amp rated conductor carrying 360 Delta Amps (90% loaded) will carry 208 Wye Amps (52% loaded) after the conversion). Because the amount of loss in an electric system is proportionate to the square of the current, reducing the current by voltage conversion lowers the electric loss associated with that portion of the electric system. Further loss reduction is typically realized through voltage conversion as older transformers and isolators are replaced as part of the voltage conversion project;

  - **Improved system reliability** – Voltage conversions on the distribution lines are similar to pole top rehabilitation work, in that older equipment is replaced with new, which allows the Company to realize corresponding SAIDI and SAIFI improvements;
  - **Reduced number of interrupted customers for single-phase failures** – When a single-phase failure occurs on the Delta system, two-thirds of the customers are interrupted; when a single-phase failure occurs on the grounded-wye system, only one phase trips, interrupting one-third of the customers;
  - **Increased system transfer capability** – Circuit conversions create the opportunity to improve transfer capability between like systems and build a platform for increased distribution automation and smart grid systems; and
  - **Reduced equipment inventory** – Eliminating the non-standard line transformer inventory would not significantly increase the cost to maintain the standard voltage transformer inventory. The non-standard line transformer population is very small compared to the standard transformer population, so the re-order points for standard voltage equipment would remain the same. It would, however, reduce and eventually eliminate the need to maintain non-standard line transformer inventory.

- <u>First zone interruption reduction</u>: This investment category reduces interruptions in the first protective zone on distribution circuits. The first zone is between the substation and the first protective devices that isolate this first section of distribution circuit from other segments of circuit. Below in Figure 115, the first zone is represented by the highlighted section. LVD circuit planners identify electric assets within the first zone that require replacement or the addition of protective schemes. Items identified for replacement include, but are not limited to, poles, cross-arms, pins and insulators, lightning arrestors, non-standard equipment, and cutouts. Protective schemes, such as fuses or reclosers, are added or upgraded to reduce the size of the first zone and reduce the number of customers that are impacted by an interruption.

FIGURE 115

ILLUSTRATION OF FIRST ZONE INTERRUPTION REDUCTION



- Zonal targeted investments: These investments improve the reliability of the Company's LVD system by reducing the likelihood of an additional interruption over the next five years or more. A zone is defined as a section of line between protective devices (i.e. fuse, recloser) for targeted improvement. A circuit planner can address multiple zones on a given circuit as necessary to improve performance. A zone for targeted improvement can include multiple protective device zones or a single protective device zone. When the Company is aware that a circuit has deficiencies, based on outage data, then the Company inspects the overhead lines on affected circuits to identify appropriate solutions to improve reliability on those circuits. Solutions in zonal targeted investments include:
    - Upgrading lightning protection to meet present standards – Company standards provide for lightning arresters every 1,300 feet on LVD lines to protect the system from lightning damage;
    - Replacing equipment at the end of expected life, including cross-arms, switches, and conductors (overhead and underground);
    - Installing new system protection devices, including fuses, switches, and reclosers;
    - Upgrading conductors to tree wire or aerial spacer cable to provide better tree protection;
    - Restoring underground cable that is no longer looped to reestablish redundancy;
    - Improving system protection coordination and reach – following certain upgrades, protective devices may no longer coordinate (a systematic application of devices to ensure clearing of permanent faults) or reach (the zone or area of protection in which a fuse, recloser, or breaker will open within an acceptable timeframe); and
    - Improving the system's capability to isolate and transfer load for improved restoration time.

Circuit Exit Enhancements

Circuit exit switches are installed on each phase outside the substation fence, providing additional safety by creating an isolation point for line workers in case the substation (and substation equipment) becomes energized. If the substation becomes energized without having the circuit exit switches opened, the line workers could be at serious risk while they are working on that line. The Company currently has approximately 275 substations eligible for exit switch installation.

Right of Way and Easement Acquisition

This investment category is used to procure necessary land or land rights for LVD projects, including both lines and substations. Acquiring the necessary land or land rights is essential to enabling LVD lines and substations projects across multiple capital sub-programs.

Planning Process

The Company uses several critical inputs and analyses to aggregate multiple data sources to best target and prioritize reliability issues. The analyses used help identify specific areas for targeted investments based on probability of future issues as well as help prioritize projects to deliver the greatest reliability benefits, based on the objectives of improving reliability (e.g., SAIDI, SAIFI, and CEMI-5). SAIDI reduction can be achieved by reducing outage frequency (SAIFI) as well as by improving duration (CAIDI) through faster and more efficient customer restoration.

The primary input for deciding where to invest is data provided by the Reliability Analytics Engine ("RAE"). The RAE data is used to help the Company evaluate how to maximize the reliability benefit to customers through reduced outages, using the strategies outlined above. Note that, as part of the Grid Archetypes process, the Company also considers other circuit characteristics, such as car-pole accident history and downed wires, to potentially modify and reprioritize the list of LVD Lines Reliability projects, and to optimize investment.

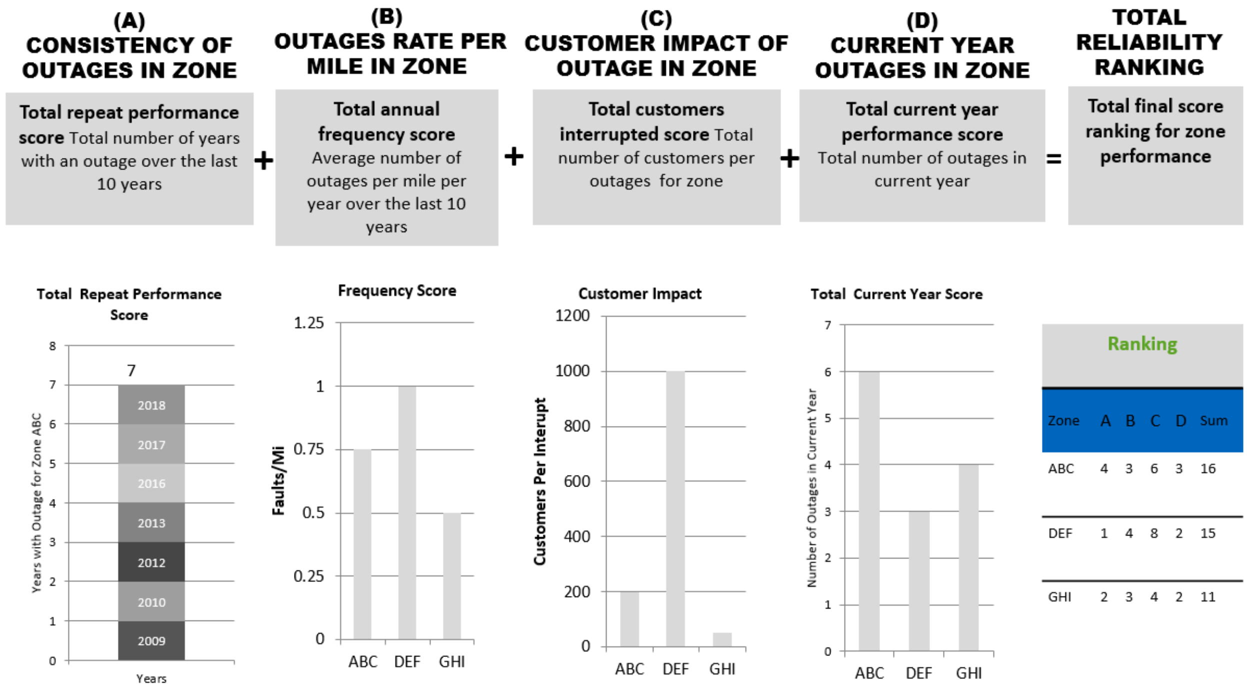
The RAE is a database used to analyze outage incident history and electric operations performance. The RAE arranges multiple data points in a manner that allows key reliability metrics (e.g., SAIFI, CAIDI, and Customers Experiencing Multiple Interruptions ("CEMI")) to be calculated at varying levels of granularity. By combining data from various sources, the RAE can also construct a complete timeline for all incidents from initial outage to final restoration. This detailed timeline breaks down an outage into analysis, dispatch, travel, and repair process steps and calculates the time spent in each step. The RAE also includes other sources such as forestry clearing data, callout success rates, and historic project spending. These can be combined with other data to analyze reliability. The RAE also produces monthly zonal analysis data reviewed by each area's LVD circuit planner. This data is analyzed to determine zonal impact to LVD system reliability.

By analyzing historical outage minutes across the grid, identifying trends, and assessing zones with the greatest potential reliability improvement opportunities, RAE provides a ranking of zones to target and maximize SAIDI reduction. Once reliability inputs are used to identify target zones on the LVD system, reliability projects are developed, evaluated, and prioritized to create an investment plan maximizing reliability benefit for customers.

Data is analyzed in four ways – (i) consistency of outages, (ii) outage rate, (iii) customer impact, and (iv) current year outages – to determine the score for any given zone compared to all other zones on the LVD system statewide. The results of the analysis are totaled to determine the final score for any given zone, as shown in Figure 116 below.

FIGURE 116

ZONAL RANKING FORMULA



The LVD Planning department collaborates with inputs from Operations, Forestry, Economic Development, and Customer Care departments. The Operations and Forestry departments work together with regular input to provide the LVD planners with the ability to serve customer needs while considering accessibility, resource, and system constraints. For example, a line may be experiencing multiple tree related interruptions. The LVD Planning circuit planner will review the recommendation to relocate the line to the road with the Forestry department and Operations field leadership to determine if this would provide the best solution for accessing the line and preventing tree related interruptions. In some cases, the Company may choose to reconductor with tree wire or aerial spacer cable (premium cable for reducing tree related interruptions) instead of relocating.

The customer-facing Economic Development and Customer Care departments provide information on customer expectations to incorporate into the planning process. For example, the Company may have a segment of line where C&I customers experience brief interruptions to their power but not extended interruptions. This could still impact their level of production as brief power interruptions cause the motors on their equipment and machinery to restart, and planners will take this into consideration as they develop plans.

Finally, line investments may need to be made as part of a circuit automation project. For example, a distribution automation scheme may be needed in a low performing area. However, to be able to consider this project for distribution automation, the system may need line upgrades such as adding a phase of conductor to create a line section consisting of all three phases. This will stage the system for building a future loop scheme with another nearby circuit in the electric system.

LVD Lines Reliability projects are prioritized using an evaluation of costs and benefits with inputs from LVD Planning circuit planners and system engineers based on their experience and knowledge of the system. This overall process is discussed in the section of this report on the concept approval process. The projects that meet long-term investment requirements and are most effective at improving reliability are sequenced for work.

An example of an LVD Lines Reliability concept approval can be found in Appendix D.

Benefits

LVD Lines Reliability projects form a critical part of the Company's glidepath for reaching 170 SAIDI minutes in 2025. Specific contributions of the LVD Lines Reliability sub-program to that glidepath were shown in Figure 5. In addition to driving system wide SAIDI improvements, LVD Lines Reliability projects consistently provide immediate benefits on the circuits or zones in which they are completed. Figure 117 below illustrates zonal performance improvements following targeted circuit improvement projects in 2017 through 2019, covering the period since the Company began selecting zones through the targeted circuit improvement investment category.

FIGURE 117
AGGREGATED IMPACT OF TARGETED CIRCUIT IMPROVEMENTS ON ZONAL PERFORMANCE

			Outages		
Project Year	Zones Targeted	Miles Targeted	Prior 3-Year Average	Post 1-Year 3-Year Average	Percent Improvement
2017	153	287	170	82	52%
2018	163	316	181	94	48%
2019	291	558	439	243	45%

Specific examples of these projects have included:

- **Spruce Road Substation, East Bay Circuit, first zone** – The substation recloser experienced two to three outages per year due to equipment failure beginning in 2015, interrupting approximately 1,532 customers with each outage. In 2018, the Company reconductored 3.5 miles to tree wire in this zone. Subsequently, those customers experienced no interruptions in 2019 or 2020 due to this equipment issue, saving approximately 560,000 annual customer outage minutes;

- **Delton Substation, Cloverdale Circuit, zone 900** – The recloser at zone 900 experienced three outages in 2014, two outages in 2015, and two outages in 2016, interrupting approximately 910 customers. In 2018, the Company relocated 1.5 miles of the three-phase conductor to the road out of the trees. Subsequently, those customers experienced no interruptions in 2019 or 2020 due to this issue, saving approximately 315,000 annual customer outage minutes.

- **Calvin Substation, Rosemont Circuit, zone 654 –** The underground cable was faulting once each year from 2015 through 2017, interrupting approximately 30 customers. This underground section was selected for underground rejuvenation to inject the cable and replaced segments of cable in 2018-2019. Subsequently, those customers experienced no interruptions in 2018 through 2020 due to this issue, saving approximately 43,000 annual customer outage minutes; and

- **Levely Substation, Sturgeon Circuit, zone 860** – The fuse at zone 860 experienced eight outages in 2017 and three outages in 2018 due to tree issues, interrupting approximately 250 customers. In 2018, the Company upgraded the three-phase conductor to tree wire over a one-mile stretch. Subsequently, those customers experienced no interruptions in 2019 or 2020 due to this issue, saving approximately 670,000 annual customer outage minutes.

ii. HVD Lines Reliability

The purpose of the HVD Lines Reliability program is to ensure the long-term safe and reliable operation of the HVD system. The HVD system is the foundation and source for the LVD system. Simply put, the LVD system cannot function without the HVD system.

The Company customizes its responses to poorly performing lines individually, based upon the configuration, construction style, inspection results, and other key factors. Lines that meet modern construction and design standards and have standard conductors will primarily receive pole top rehabilitation, while lines that utilize non-standard construction or equipment will typically be rebuilt. Occasionally, lines that meet modern standards will be rebuilt due to problems such as access impediments or upgrades improving operational flexibility. As part of HVD line rebuild and pole top rehabilitation projects, the Company clears the line ROW and addresses hazard trees from a forestry perspective in advance of the line work. This line clearing forestry work is included as part of the project capital expenditures. The Company initiates projects to upgrade assets to improve resilience to deterioration and weather. Work in the HVD Lines Reliability sub-program consists of four investment categories: (i) HVD line rebuilds – complete overhead line rebuilds including insulator, conductor, cross-arms, and structure replacements; (ii) pole-top rehabilitations, which include replacing deteriorated cross-arms, insulators, cross-arm braces, and hardware on pole tops as necessary; (iii) pole replacements; and (iv) switch replacement projects, including SCADA additions.

Over the next five years, the Company plans to focus substantial investment in this sub-program to rebuild HVD lines and deliver immediate customer reliability benefits, clearing a backlog of deteriorated assets, as shown below:

FIGURE 118

HVD LINES RELIABILITY CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Line Rebuilds	36.4	46.3	51.4	57.6	57.6
Pole Top Rehabilitations	7.6	12.4	11.0	6.7	6.7

Pole Replacements	15.6	18.6	15.6	13.8	13.6
Switches	0.6	0.7	0.7	0.7	0.7
MOABS SCADA Switches	3.7	0.5	-	-	-
Total	**63.9**	**78.4**	**78.7**	**78.8**	**78.6**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Line Rebuild Miles	51.6	96.7	100	110	108
Pole Top Rehabilitation Miles	84.5	131.8	115	70	70
Pole Replacements	800	880	725	625	600
Switches	7	7	7	7	7
MOABS SCADA Switches	35	11	-	-	-

Line Rebuilds

A rebuild involves replacing every insulator, conductor, cross-arm, cross-arm brace, all hardware pieces, and structure within the line section identified in the project scope. The Company prioritizes lines or line sections for a rebuild when that full line or line section rebuild is more effective than replacement/rehabilitation of individual components due to the state of deterioration, and/or the line is built with outdated construction standards such as unshielded, small single layer conductor, and/or copper conductor. The Company's experience with line rebuilds has demonstrated line rebuild completion on such lines dramatically reduces customer outages on the rebuilt lines or line segments .

Pole Top Rehabilitation

The Company performs HVD pole top rehabilitation projects to improve the condition of deteriorated cross-arms, insulators, cross-arm braces, and hardware on pole tops through the replacement of those components. For the HVD line sections identified for pole top rehabilitation, the Company utilizes qualified journeyman line workers to perform visual inspections of every structure within the defined project scope to identify any anomalies with the components on a structure. If anomalies (e.g., split or cracked cross-arm, chipped, cracked or tipped insulator, loose or detached cross-arm brace, etc.) are identified, the Company may replace the entire pole top assembly (all of the previously stated components), or only the component(s) requiring replacement. When pole top assembly components are replaced, they are brought up to current Consumers Energy standards. For example, pin-type insulators are replaced with post-type insulators. Additionally, to maximize efficiency and reliability improvement of an HVD line section through a pole top rehabilitation project, the Company will also perform a pole inspection of the line section when the last pole inspection was performed six or more years prior to the date of the project. Structures identified through this inspection process requiring replacement within the line section of the project will be replaced during the rehabilitation project.

Pole and Switch Replacements

This investment category replaces individual poles and switches based on inspection results. Because of the relatively short lead time to plan, design, and construct a pole replacement, individual poles and switches are identified weeks, not years, in advance. While individual poles are not scheduled for replacement until fairly close to the execution date, the Company does identify in advance which HVD lines will be inspected in a given time period, meaning the Company can plan which HVD lines will require pole replacements based on inspection results. Given data about historical pole inspection failure rates, the Company determines which HVD lines will require replacements, and how many poles on a given line are likely to require replacements.

Planning Process

To identify locations for line rebuilds and pole top rehabilitation, the Company focuses on lines that are consistently poor performers and looks for the best remediation strategy to prevent future outages in the most economical way. While continuously monitoring the reliability of the HVD lines system, the Company performs an annual review of its HVD line sections, considering both line performance and line condition, determining the lines and line components to be planned in the next year or years, as some projects may be large enough to span multiple years.

Line performance is an aggregate of both the number of incidents on the line segment and the number of customer outage minutes generated by an incident to the line segment. The primary driver for investment decisions is line performance. Therefore, lines with the highest average of incident rates and customer outage minute totals in a rolling three-year period are given higher priority for remediation.

An illustrative sample of the data utilized in the line performance analysis is shown below.

FIGURE 119

HVD OUTAGES SORTED BY NUMBER OF INCIDENTS, 2017-2019

Line Name	Voltage	Line Length	2017-2019 Total Incidents	2017-2019 Total Customers Affected	2017-2019 Total Customer Minutes
WALDRON (DOWLING - FRONTIER)	46	37.6	6	32,382	8,724,678
GUN LAKE (HAZELWOOD - GUN LAKE)	46	24.2	6	30,690	8,516,181
EATON RAPIDS (RICE CREEK - ISLAND RD)	46	34.6	6	17,558	4,475,203
GALESBURG (MORROW - SONOMA)	46	17.6	5	13,154	2,300,878
MORRICE (CORNELL - TIHART)	46	33.7	5	17,545	967,414
HOMESTEAD (HODENPYL - FARR RD)	46	62.3	4	26,649	9,206,334
SARANAC (THOMPSON RD - RICKERT)	46	12.3	4	22,615	8,945,224
ATTWOOD (RICKERT - THORNAPPLE)	46	13.7	4	11,568	3,955,572
RIGA (SAMARIA - BEECHER)	46	36.1	4	15,141	1,938,318
FINE LAKE (BARRY - LAFAYETTE)	46	21.7	4	8,578	1,923,271

FIGURE 120

HVD OUTAGES SORTED BY CUMULATIVE CUSTOMER MINUTES, 2017-2019

Line Name	Voltage	Line Length	2017-2019 Total Incidents	2017-2019 Total Customers Affected	2017-2019 Total Customer Minutes
MT PLEASANT (SUMMERTON - MT PLEASANT)	46	6.2	2	12,402	10,485,891
HOMESTEAD (HODENPYL - FARR RD)	46	62.3	4	26,649	9,206,334
SARANAC (THOMPSON RD - RICKERT)	46	12.3	4	22,615	8,945,224
WALDRON (DOWLING - FRONTIER)	46	37.6	6	32,382	8,724,678
GUN LAKE (HAZELWOOD - GUN LAKE)	46	24.2	6	30,690	8,516,181
MANCHESTER (CEMENT CITY - PARR RD)	46	28.1	1	15,883	7,289,714
BRETON (BEALS RD - BRETON)	46	6.4	1	7,947	6,937,731
METRO (RANSOM - BUCK CREEK)	46	15.2	2	12,053	6,766,745
TUSTIN (WEXFORD - CADILLAC)	46	13.7	1	4,755	6,711,132
GOODALE (LAFAYETTE - VERONA)	46	19.3	3	10,027	5,284,406

The Company gives slightly more weight to the HVD line sections with a higher number of incidents compared to outage minutes. Multiple incidents are a possible sign of a deteriorating system, which can be a leading indicator of future poor performance and can drive negative customer satisfaction. To ensure that the Company does not overlook an HVD line section requiring improvement by considering number of incidents alone, line sections with higher outage minutes are also considered. In the review of this sort by outage minutes, the number of incidents is included toward consideration of a potential course of action. For example, while a large thunderstorm could result in many customer outage minutes, the fact that it is a single event means the Company may not need to conduct a reliability project beyond fixing the storm damage if the line does not otherwise show deterioration. The number of incidents and the outage minutes associated with HVD line sections are two important inputs into the decision process to undertake a project, but they are not the only inputs considered. The Company also considers the configuration of an HVD line, because events on poor-performing radial lines result in more interruptions to customers compared to those on looped HVD lines. Additional inputs such as inspections, a possible field assessment, and knowledge of the system condition are applied by the Company's engineers before a final course of action is determined.

In addition to line performance, line condition is taken into consideration, based on high pole rejection rate on the line in pole inspections, or based on results of the Company's helicopter inspections or biannual ground patrols (discussed previous in the Demand Failures section of this report), or if the line is of non-standard (outdated) construction. An example of HVD pole deterioration, as identified by a helicopter inspection, is shown in Figure 121 below.

FIGURE 121

DETERIORATION OF HVD POLE TOP FROM HELICOPTER INSPECTION

In addition to the above inputs, line condition can be impacted heavily by the age of the line segment. However, the Company does not replace HVD lines and equipment simply due to age. Unless an operational problem or an inherent failure mode is identified for a particular manufacturer or vintage of HVD conductor or equipment, the Company does not have a systematic program to replace aging lines, crossarms, insulators, or other pole top equipment, if there are no performance or condition issues on the line.

The Company also uses a model that specifically addresses HVD line system performance. The model prioritizes HVD line segments based on actual outage history, conductor type, shielding, and the potential customer impact if this line segment were to fail. It provides a first cut for Company engineers regarding where preventative outage work would be most beneficial. This model is used to help select some projects and to validate projects that were previously identified. However, the Company does not solely rely on this model to determine line segments to be rebuilt or rehabilitated. Company engineers review the output of sorting HVD lines by number of incidents and outage minutes along with the output of this model and then apply their knowledge of the system condition, including recent inspection information, and may also perform a field assessment before making a final determination.

For the pole replacement inspection category, as discussed above, the Company does not identify specific poles for replacement far in advance, but instead identifies HVD lines for inspection, which informs where pole replacements will be needed, because HVD line poles are not replaced due to age, but are only replaced based on results of a physical or visual pole inspection. The pole replacements planned for completion are based on the preceding year's inspections. Switches are replaced due to issues being identified with the switch, or the pole the switch is mounted to is rejected by a pole inspection.

Project Selection

In determining if a line rebuild or a pole top rehabilitation is appropriate, the Company customizes its responses to poorly performing lines individually, based on the configuration, construction style, inspection results, and other key factors. Lines that meet modern construction and design standards and have standard conductors will primarily receive pole top rehabilitation, while lines that utilize non-standard construction or equipment will typically be rebuilt. Occasionally, lines that meet modern standards will need to be rebuilt; this could be due to access issues or upgrades that could improve operational flexibility.

Occasionally, projects for lines outside of the worst performers are developed and prioritized based on completing multi-year plans, rapidly degrading reliability, customer commitments, or other unique circumstances. Unique circumstances are typically the result of addressing a reliability need as an ancillary benefit during a project for which the primary benefit may be capacity or asset relocation focused.

There are occasions in which an HVD line suddenly performs poorly, which can prompt a need to quickly react and reprioritize line rebuild or pole top rehabilitation projects. For example, in 2017, the Company saw emergent poor performance on the Waldron Line. The Company's initial reliability analysis in 2016, used to prioritize 2017 projects, had not indicated any need for action on the Waldron Line in 2017. However, in April 2017, three separate incidents in one week on the Waldron Line caused interruptions to about 5,200 customers. As a result, the Company immediately prioritized pole top rehabilitation on nine miles of the line, which was completed by October 2017.

An example of a concept approval for an HVD Lines Reliability project can be found in Appendix D.

Benefits

HVD Lines Reliability projects form a critical part of the Company's glidepath for reaching 170 SAIDI minutes in 2025. Specific contributions of the HVD Lines Reliability sub-program to that glidepath were shown in Figure 5 of this report.

Line rebuilds substantially improve the performance of a line, reducing or eliminating outages and correspondingly reducing or eliminating interruptions to customers caused by that line. Figure 122 below shows how, after completing a rebuild for which line outages were a factor driving the need for the rebuild, a line section typically experiences zero or minimal line equipment-related outages. In the table, Prior Outages represent the number of line outages that occurred three to eight years before the rebuild Completion Date. Post Outages represent the number of line outages that occurred three to eight years after the Completion Date within the rebuilt line section. Customers realize the benefit of fewer outages when the Company rebuilds an HVD line section.

FIGURE 122

Impact of Line Rebuilds on Outages				
Line Description	**Completion Date**	**Prior Outages**	**Post Outages**	**Miles Targeted**
Barry – Broadmoor	2/17/2009	5	0	9.0
Dowling – Beecher	2/24/2009	4	0	21.6
Warren – Grout	3/4/2009	2	0	19.6
Monitor – Almeda	4/8/2010	1	1	22.5
Whitestone Point	6/30/2010	10	0	4.0
Parma – West	4/11/2011	2	0	10.9
Standish	7/6/2011	1	0	10.6
North Adams – North	10/10/2011	2	0	6.3
Mancelona	10/21/2011	1	0	9.0
Parma – East	11/1/2011	3	0	11.9
Nashville East	2/24/2012	3	0	11.0
Bridgeport	6/15/2012	1	0	9.5
Suttons Bay – South	10/9/2012	2	0	10.2
North Adams – Center	1/14/2013	1	0	3.8
Fremont – West	2/28/2014	2	0	4.4
Fremont – East	7/15/2014	4	0	4.6
Sanford	11/3/2014	3	0	6.3
Carson City – South	12/3/2014	7	0	6.2
Union Street	2/12/2015	2	0	4.7
Nashville Center	5/29/2015	1	0	5.5
Markey – North	5/29/2015	2	0	5.0
Carson City – North	12/1/2015	1	0	6.2
North Adams – South	12/29/2015	1	0	3.7
Peach Ridge	6/20/2016	1	0	2.7
Nashville – West	8/29/2016	2	0	5.5
Pierson – Trufant West	1/24/2017	1	0	4.8
Textron	1/27/2017	1	0	1.0
Bridgeport	1/27/2017	1	0	3.9
Manitou Beach	3/29/2017	1	0	6.5
Augusta	5/1/2017	2	0	2.8
Pierson – Trufant East	5/30/2017	3	0	5.8
	Totals	**73**	**1**	**239.5**

Similarly, in 2017 the Company performed pole top rehabilitation work on sections of the Gun Lake and Wentworth HVD lines. In the preceding four years, the lines each experienced two outages. Since the completion of the work, neither line has had any outages, demonstrating the clear benefits to customers of fewer outages when the Company rehabilitates an HVD line section.

iii. LVD Substation Reliability

The LVD Substations Reliability sub-program ensures the long-term safe and reliable operation of LVD substations, which are the interface point between the HVD lines and LVD lines on the Company's system. The capital expenditures in this sub-program include investments to install new substations or substation equipment and replace existing substations or substation equipment.

Across the electric system, there is minimal LVD substation redundancy. If an LVD substation failure occurs in an urban area, depending on load levels at the time of failure, it may be possible to transfer customers to an adjacent substation through LVD line switching. If an LVD substation failure occurs in a rural area, it is unlikely that such a customer transfer could take place. Assuming no transfer ability exists, LVD substation failures create long duration outages for customers. To mitigate this risk, the LVD Substation Reliability sub-program invests in several categories, including: (i) new or rebuilt substations; (ii) new mobile substations; (iii) animal mitigation; (iv) transformer replacements; and (v) regulator replacements.

The Company's five-year investment plan in this sub-program, shown below, maintains a consistent level of investment each year. In 2025, the Company expects to have finished its planned mobile substation purchases and will shift investment to other investment categories.

FIGURE 123

LVD SUBSTATIONS RELIABILITY CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
New or rebuilt substations	3.2	4.5	4.5	4.5	6
Mobile substations	1.7	3	3	3	0
Animal mitigation	3.7	4	4	4	4.5
Transformer replacements	3	2	2	2	3
Regulator replacements	1.5	1	1	1	1
Other	0.2	1	1	1	1
Total	**13.3**	**15.5**	**15.5**	**15.5**	**15.5**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025

New or rebuilt substations	2	3	3	3	4
Mobile substations	1	1	1	1	0
Animal mitigation	36	40	40	40	50
Transformer replacements	5	3	3	3	5
Regulator replacements	44	33	33	33	33
Other replacements	4	5	5	5	5

The scope of the five-year plan in this sub-program includes the following:

- Installing or rebuilding two to four substations per year to improve reliability, operating flexibility, and until there are no customers directly served from a hydro generation plant;
- Purchasing four new mobile substations in order to maintain a strong operating fleet;
- Installing animal mitigation measures until all the distribution substations are brought up to current substation animal mitigation standards;
- Replacing three to five substation transformers and approximately 33 substation regulators per year, based on degrading trend data;
- Installation of transrupters to improve system protection; and
- Replacing substation transformer bushings.

Animal Mitigation

LVD substation animal contacts typically result in customer interruptions. The Company's current animal mitigation standards were developed based on research conducted at Michigan State University, experiments conducted at the Company's Marshall Training Center, utility industry reports and best practices (e.g. EPRI – Electric Power Research Institute), and experience gained from previous animal mitigation projects.

The purpose of each animal mitigation project is to keep animals, such as squirrels and raccoons, out of the substation and to insulate equipment to extend touch potential should an animal get into a substation, with specific measures chosen based on substation characteristics. Common animal mitigation measures include: (i) 1-inch mesh fence (squirrels can squeeze through larger mesh); (ii) concrete gate foundations (minimizes gaps and frost heave that create gaps over time); (iii) polycarbonate panels (3-foot panels installed at the top of the fence to mitigate animals from climbing over the fence); (iv) pole wraps and line discs (installed on poles and wires outside the substation to mitigate aerial access to the substation); (v) interior and exterior stone (eliminate gaps at the fence bottom to mitigate animals from crawling under the fence); and (vi) bushing guards on regulators and reclosers to extend touch potential to mitigate contact to energized components should an animal climb on equipment.

Line discs and pole wraps are incorporated into the current LVD substation animal mitigation standard and utilized where applicable, to reduce the potential for land animals to enter the substation from above. The Company also typically clears vegetation within 10 feet from the substation fence, except if a city or township requires vegetation to be closer for screening purposes or if the substation fence is within 10 feet of the property line and the adjacent property has vegetation up to the property line. The Company's animal mitigation standards do not include measures to prevent bird intrusions because birds can fly over fences and barriers, but mitigation measures such as bushing guards can mitigate touch potential on energized components.

Planning Process

The Company uses several inputs and analyses to determine how to best target LVD Substations Reliability issues. These inputs help to identify specific areas to target investments based on probability of future issues and help to prioritize projects that will deliver the greatest reliability improvements based on SAIDI and SAIFI. These inputs include: (1) the RAE and input from LVD circuit planners; (2) reliability improvement initiatives; (3) animal intrusion data; (4) equipment trend data; and (5) mobile substation planning.

1. RAE and input from the LVD circuit planners:
    - The RAE analyzes and aggregates a large amount of customer and operational data across the grid. The RAE produces a bi-weekly Repetitive Outage report that helps identify areas of frequent customer outages.
    - Historical outage trends are analyzed to identify parts of the grid where reliability concerns are greatest based on the total number of outages, trends in reliability performance, and the potential reliability impact.
    - The Company may initiate a substation project to supplement an LVD Lines project (e.g., new substation, new circuit, substation equipment upgrades, and animal mitigation). When new substations are proposed, long range studies compare the SAIDI/SAIFI/CAIDI benefits and economic costs of the substation alternative with other solutions, and consider long-term system capacity needs to optimize new substation locations. A new substation may be installed if the system reliability improvements and economic benefits are comparable to other solutions.

2. Reliability improvement initiatives:
    - Collaboration across departments informs substation planners about operational concerns and system constraints that may trigger a need for substation projects (e.g., identification of substations with working clearance constraints, replace 138 kV spring-operated ground switches ("SOGS") with transrupters, and replace 138 kV fuses with transrupters).
    - Installation of new distribution substations to serve customers that are currently served from a Hydro Generation Plant.
    - Animal mitigation initiatives to bring all distribution substations up to the current substation animal mitigation standards.

3. Animal intrusion information:
    - Animal mitigation projects are implemented following one animal-caused outage inside the substation. If an animal can get inside a substation, the animal could climb the structures and equipment, contacting energized electrical components and causing an outage.
    - Animal mitigation projects are also initiated when animals are observed within the substation, even though an outage may not have occurred. The presence of an animal indicates that a future outage is possible.
4. Equipment Trend Data:
    - Planned replacement of substation equipment may be triggered by trend data that indicates degrading equipment condition.
    - Dissolved Gas Analysis trends help identify when replacement of substation transformers and regulators are needed.
5. Mobile Substation Planning:
    - The Company's mobile substation fleet is maintained based on historical usage, and the Company purchases new mobile substations to replace those nearing end of life.
    - Mobile substations are used when no load transfer options are available at a substation site location. It is typically parked next to a substation and temporarily attached to the feeder circuit. The Company uses the mobile substation to pick up the circuits and de-energize portions of part or all of a substation to perform project and maintenance work safely, and with no outage to customers. Figure 124 Below shows an example of a mobile substation and an underbuilt line.

FIGURE 124
MOBILE SUBSTATION

Project Prioritization and Selection

Once the Company has identified substation projects based on the above-mentioned inputs, they are scheduled and executed. The Company balances the need to improve performance, while also addressing degrading trend data and supporting our reliability initiatives to minimize customer outages.

System planning is an ongoing process. Project engineering and scheduling typically occur in the current year for the following year’s construction. New projects can be inserted into the plan based on experienced system outages and operational concerns, which may result in the deferment of previously planned projects depending on need and available construction resources and/or mobile substations.

Benefits

Reliability investments minimize potential adverse impacts on customer experience through the improvement of the overall energy reliability, operation, and maintenance of the distribution substations over the long term. Addressing operational concerns, planned replacement of degrading equipment and maintaining an adequate mobile substation fleet reduces the potential of long-term outages and restoration delays, which can result in SAIDI and CAIDI minute avoidance in the year that operational issues are experienced.

iv. HVD Substation Reliability

The HVD Substations Reliability sub-program ensures the long-term safe and reliable operation of HVD substations, with investments to replace existing substation equipment. These investments are intended to reduce customer outage frequency (SAIFI) and reduce the number of emerging repetitive outage customers, as well as the customer outage durations as represented by CAIDI and SAIDI. This sub-program consists of four investment categories: (i) circuit breaker and circuit switcher replacements; (ii) transformer bushing replacements; (iii) switch replacements; and (iv) other targeted replacement programs for specific equipment, such as potential transformer replacements and substation lightning arresters.

The Company's five-year investment plan in this sub-program is as follows:

FIGURE 125

HVD SUBSTATIONS RELIABILITY CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Circuit Breaker and Circuit Switcher Replacements	3	3.3	2.5	2.5	2.5
Transformer Bushing Replacements	1.2	1	1	1	1
Switch Replacements	0.6	0.1	1.4	1.4	1.4
Other	0.4	1.1	0.5	0.5	0.5
Total	**5.2**	**5.4**	**5.4**	**5.4**	**5.4**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Circuit Breaker and Circuit Switcher Replacements	20	19	14	14	14
Transformer Bushing Replacements	12	8	8	8	8
Switch Replacements	17	1	25	25	25
Other	12	26	12	12	12

Investment Categories

Circuit breakers and circuit switchers are key and integral components of the HVD protection system. The purpose of these devices is to minimize customer outage impact and mitigate equipment damage when the system experiences and clears an electrical fault. The units replaced are generally 1950s and 1960s vintage oil breakers and their performance coupled with the increasingly limited availability of parts are the two key inputs driving these replacements.

Transformer bushings replacements include bushing types with high failure rates, such as ABB/Westinghouse Type O+C, and bushings with observed degradation. The Type O+C bushings are known industry wide to have higher failure rates than average bushing failure rates. The Company has been systematically replacing Type O+C bushings for several years, based on customer impact and consideration of other scheduled work in the substation to maximize workforce efficiency and utilization.

The Company replaces obsolete switches in conjunction with other substation work, in order to maximize efficiency and workforce utilization.

In the “Other” substation equipment category, the current emphasis is on potential transformers manufactured by Moloney and a few other vendors that have been identified as being prone to catastrophic failure posing a safety risk to employees in substations. These transformers are used for station power and instrumentation purposes.

Planning Process

The key inputs used in the project planning process are test data, analytic algorithms, reliability improvement initiatives, and equipment trend data. The test data reviewed includes transformer and battery electrical test data and circuit breaker operational testing and operation history. The data from oil dissolved gas tests of transformers, Load Tap Changers, circuit breakers, and voltage regulators are reviewed and set to subscription Industry Standard Analysis Algorithms.

The Criticality, Health, and Risk (“CHR”) analytic algorithm has been developed for specific equipment groups. The Company developed CHR in collaboration with Digital Inspections experts. This algorithm has been customized for our equipment based on equipment analysis experience coupled with industry parameters. Where applied, the algorithm will produce a risk analysis based on an applied criticality (to the system) input and a health value developed using test results. This can be a useful component in the prioritization process for equipment replacement projects. Based on these results, the reliability engineers may then initiate a substation equipment replacement project. Additionally, collaboration and input from field organizations and other departments provides substation reliability engineers with information regarding operational concerns that can initiate individual substation equipment replacement projects.

Reliability improvement initiatives include:

- Collaboration across departments to provide substation planners with information regarding operational concerns that can initiate individual substation equipment replacement projects;
- Planned replacement of obsolete switches, or those with known operational issues;
- Planned replacement of obsolete transformer bushings, or those with known failure modes and histories;
- Planned replacement of obsolete circuit breakers, or those with known operational issues;

- Planned replacement of obsolete potential transformers, or those with known failure modes and histories; and
- Planned replacement of obsolete circuit switchers.

For equipment trend data, planned replacement of substation equipment may be triggered by trend data that indicates degrading equipment condition. Dissolved Gas Analysis trend data is also used to identify when replacement of substation transformers and regulators are needed.

Project planning is an ongoing process. Project engineering and scheduling typically occur in the current year for the following year's construction. New projects can be inserted into the plan based on operational concerns, which may result in the deferment of previously planned projects depending on program funding, available construction resources, and/or mobile substation availability.

Benefits

HVD substations are typically designed with some redundancy, such that the first contingency should not result in any interruptions to customers, which limits the SAIDI impact of any single failure of an HVD substation component. However, because HVD substations are typically the interface point between the transmission provider and Consumers Energy, they represent particularly critical locations on the electric distribution system, as a second contingency could cause interruptions to many customers. For radial configurations where customers are fed by a single line, the failure of any component can cause outages for all customers on a line, making the devices contained in such substations critical to serving customers. Therefore, preventative reliability work at HVD substations, to keep this redundancy in place, is vital to overall grid reliability.

v. System Protection

The System Protection sub-program targets replacement of relays that are reaching end of life, which are more likely to fail. Investments in this program are directed at replacing obsolete, high maintenance electromechanical ("EM") relays with digital devices and replacing obsolete digital relays that are older than 25 years. Many of these relays are either no longer manufactured or no longer have parts available, while those parts that are available are no longer cost-effective to replace. Replacing end-of-life relays prevents large customer outages due to relay failure, and reduces O&M expenses, as older electromechanical relays require more periodic maintenance than newer digital relays.

The Company's five-year plan for this sub-program is as follows, and includes a planned increase in investment starting in 2023:

FIGURE 126

SYSTEM PROTECTION CAPITAL INVESTMENTS

5-Year Capital Plan (all values in $ millions)					
	2021	2022	2023	2024	2025
Total Spending	2.3	2.4	3.3	3.4	3.4
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Line Exit Relay Replacements	35	31	47	48	48

<u>Planning Process</u>

Approximately 17% of the protective relay population is older than the designated design life; this increases to 32% for the population of EM relays. Experience has shown that as relays age they are found to be out of tolerance more often; therefore, more frequent field testing and calibration is required in order to assure proper performance. Digital relays are tested less often than EM relays, reducing O&M testing expenses. Both digital and EM relays also typically have an increased failure risk as they age.

The Company identifies investments in this sub-program through various factors, including:

- Overall Protection System performance;
- Component technology – EM, Solid-State, Digital;
- Manufacturer information on known defects, problems, or alerts;
- Component availability for replacement/repair, spare parts, cost; and
- Component age.

While the Company does not have definitive relay replacement thresholds for all relay types, several factors are considered when selecting projects. A key criterion is the performance history of specific relay types. If a specific relay type or model is known to have failure or maintenance issues, it will be prioritized. One EM relay model requires maintenance twice as often as other EM relays in order to keep them within their setting tolerance. These relays are targeted for replacement to reduce O&M expenses as well as the risk of failure. Similarly, relay age is often a factor as older relays typically have an increased failure risk.

The Company also targets replacing relay schemes that rely on analog phone lines for communication. These phone circuits are becoming increasingly more expensive as the phone companies reduce their support of analog circuits. Replacing relays with newer communication technologies reduces the O&M expense associated with these circuits.

System Protection projects are also coordinated with other Reliability or Capacity projects to take advantage of the planned system element outages needed to support the construction. Completing relay projects at the same time as other projects reduces labor costs and reduces the number of planned system element outages. The System Protection program also supports NESC working space requirements.

Generally, relay replacements are planned one year in advance of the desired construction year. Relay replacements for the next two years are tentatively identified to assist with project coordination and to accommodate time to engineer larger projects. Some future projects may be addressed by system improvements completed using other capital programs. Timing of relay replacements may be advanced or delayed to coordinate with other known project work and to take advantage of the planned system element outages.

Benefits

The failure of a relay to trip properly under fault conditions can lead to severe system consequences, including extended outages for customers, increased likelihood of major equipment or conductor damage, and possible unsafe employee or public safety conditions. Proactively identifying and replacing relays that are prone to failure greatly reduces the risk of these consequences.

Digital relays contain oscillographic recording functions that allow for evaluation of system conditions in real time and enable remote interrogation by the protection engineer to help determine the location of HVD system faults much more quickly. Identifying the fault location quicker and with more precision allows repair crews to get to the problem location sooner, leading to faster repairs and restoration, thus reducing CAIDI.

Newer digital relays are also cheaper to purchase and require less panel space than older relays. One HVD relay scheme project typically replaces six EM relays with two new digital relays. Digital relays are designed with more flexibility in settings and applications, so they can be reconfigured easily to accommodate proposed projects or reconfigurations of the HVD system without incurring additional relaying expense.

As the relay population continues to age, more money will need to be spent on O&M, because experience shows that as relays age they are out of tolerance more often, in turn requiring more frequent field testing and calibration to ensure proper performance. Digital relays require testing less often than EM relays, reducing O&M test expenses. Experience has shown that digital relays can be tested once every five years instead of once every four for EM. Further, the time spent to test and calibrate digital relays is 50% less than a comparable EM relay. Replacing old EM relays will improve functionality and performance and reduce O&M expenses. Considering these reductions, it is estimated that a modern digital relay package requires 87% less O&M expense on average to maintain than a comparable EM unit.

vi. LVD Repetitive Outages

The LVD Repetitive Outages sub-program addresses areas of the distribution system that consistently experience recurring customer interruptions, measured by the CEMI index, inclusive of MEDs. CEMI measures how many customers have experienced more than a given number of interruptions in a particular year. For LVD Repetitive Outages, the Company considers MPSC CEMI-5+, or the percentage of customers who experience five or more interruptions annually. Investments in this program address issues of frequent interruptions by targeting specific zones for improvements.

The investments in this program also address customer complaints related to frequent outages by targeting a zone for improvement. This active and targeted work to improve the CEMI-5 index tends to decrease the number of customer complaints. The Company's CEMI-5 targets were discussed earlier in the section of this report outlining the EDIIP metrics.

Over the next five years, the Company plans to generally maintain its level of investment in this program, albeit with a modest increase, as the Company did not meet MPSC standards for CEMI-5 performance in 2019. Spending in this sub-program had been on a generally downward trend through 2018, in favor of the LVD Lines Reliability sub-program, but the purpose of shifting some work back to this sub-program is to complete more work proactively rather than wait until a given circuit has experienced enough outages to trigger the need for a more reactive project. The Company's five-year plan is as follows:

FIGURE 127

LVD REPETITIVE OUTAGES CAPITAL INVESTMENT

5-Year Capital Plan (*all values in $ millions*)					
	2021	2022	2023	2024	2025
Total Spending	7.7	10.2	10.6	11.0	11.3
Unit Forecast					
	2021	2022	2023	2024	2025
Repetitive Outage Zones	221	252	282	282	282

Different solutions are considered depending on the specific conditions of the area being targeted. Depending on specific circuit conditions and attributes, typical investments include:

- **System protection upgrades (e.g., to fuses, switches, reclosers)** – This prevents or minimizes damage to lines and equipment caused by system faults, using devices that maintain continuity of service by segmenting the electric distribution system into smaller sections, minimizing the number of customers affected by any individual outage;

- **Upgrading lightning protection to meet present standard**s – For example, the Company installs lightning arrestors (otherwise known as surge arrestors) every 1,300 feet as a Company standard; and

- **Replacing deteriorated or non-standard equipment** – Items identified for replacement include poles, cross-arms, pins and insulators, lightning arrestors, non-standard equipment, and cutouts.

Planning Process

RAE data, as discussed previously in the LVD Lines Reliability section, is the primary input in deciding where to invest for repetitive outages. One RAE output is a monthly zonal analysis report, which is reviewed by each area's LVD circuit planners. The report is broken down to identify specific zones, showing the number of customers that experience repetitive outages in each zone of the circuit. By looking at areas where customers are likely to experience five or more interruptions annually, the Company can develop projects that have the greatest reliability benefit for the highest number of customers first.

Figure 128 below shows a segment from the monthly zonal summary report. In this example, several customers had experienced 10 or more interruptions on the circuit. There were two zones that contributed to a majority of these interruptions. Based on this information, an LVD circuit planner would look at the detailed information, an example of which is shown in Figure 129, to identify appropriate measures to reduce future interruptions.

FIGURE 128

SCREENSHOT EXAMPLE OF ZONAL ANALYSIS SUMMARY REPORT

Protective Device 1	Protective Device 2	Protective Device 3	Protective Device 4	Protective Device 5	Protective Device 6	Total Customer Interruptions
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]				10
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0078[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0079[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0098[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0632[1]			11
1335-04-SUB[0]	1335-04-0164[3]	1335-04-0093[7]	1335-04-0632[1]	1335-04-5576[0]	1335-04-0149[1]	12

FIGURE 129

SCREENSHOT EXAMPLE OF ZONAL ANALYSIS SUMMARY REPORT DETAIL

FEEDER_ID	LCP	MED-DAY	INCID_ID	YEAR	MONTH	DAY	CUST	C&I	CUST-MINS	AOF	CAUSE
133504	93	yes	3877421	2019	2	24	329	36	40235.5	Primary	Trees
133504	93	no	3907322	2019	3	23	331	36	32075.2	Primary	Car Pole accident
133504	93	no	8132253	2019	5	19	270	30	26532	Primary	Weather
133504	93	no	8134565	2019	5	19	270	30	19208.3	Primary	Equipment Failure
133504	93	no	8135185	2019	5	19	328	36	73758.8	Primary	Trees - Outside ROW
133504	93	no	8214344	2019	7	20	111	12	20878	Primary	Animal
133504	93	no	8241968	2019	8	6	331	36	40636.2	Primary	Equipment Failure

The LVD Planning group collects feedback from customer-facing groups, such as Business Customer Care, to better understand the priorities and needs of customers to incorporate into the investment planning process. For example, a segment of line may not be experiencing multiple outages longer than five minutes. However, customers on that line might be experiencing brief interruptions causing their motors to restart and reduce production.

Project Prioritization and Selection

Once the Company has identified repetitive zones to target on the LVD system, it develops, evaluates, and prioritizes projects. The circuit planners start by looking at outage history from OMS to decide which circuits or zones to target, evaluating multiple alternative proposed solutions for each reliability concern (e.g., pole top maintenance, forestry clearing, or fusing) to determine the best customer reliability benefit. After the analysis is complete, the circuit planner submits the best solution as a proposed concept. Ideally, this sub-program addresses issues quickly by designing short lead time projects that address issues on a short turnaround time. Projects are coordinated with Forestry line clearing work to maximize improvement and ensure the correct zones are targeted.

A wide range of repetitive outage solutions are applied depending on each situation. At times, a long-term solution may be considered under the LVD Lines Reliability sub-program. This can include relocating a line over multiple parcels, installing an aerial spacer cable, or reconductoring or reconfiguring the circuit. Projects are prioritized by the program planner using a cost-benefit analysis, based on the number of customers impacted, number of complaints, and number of interruptions.

Timing

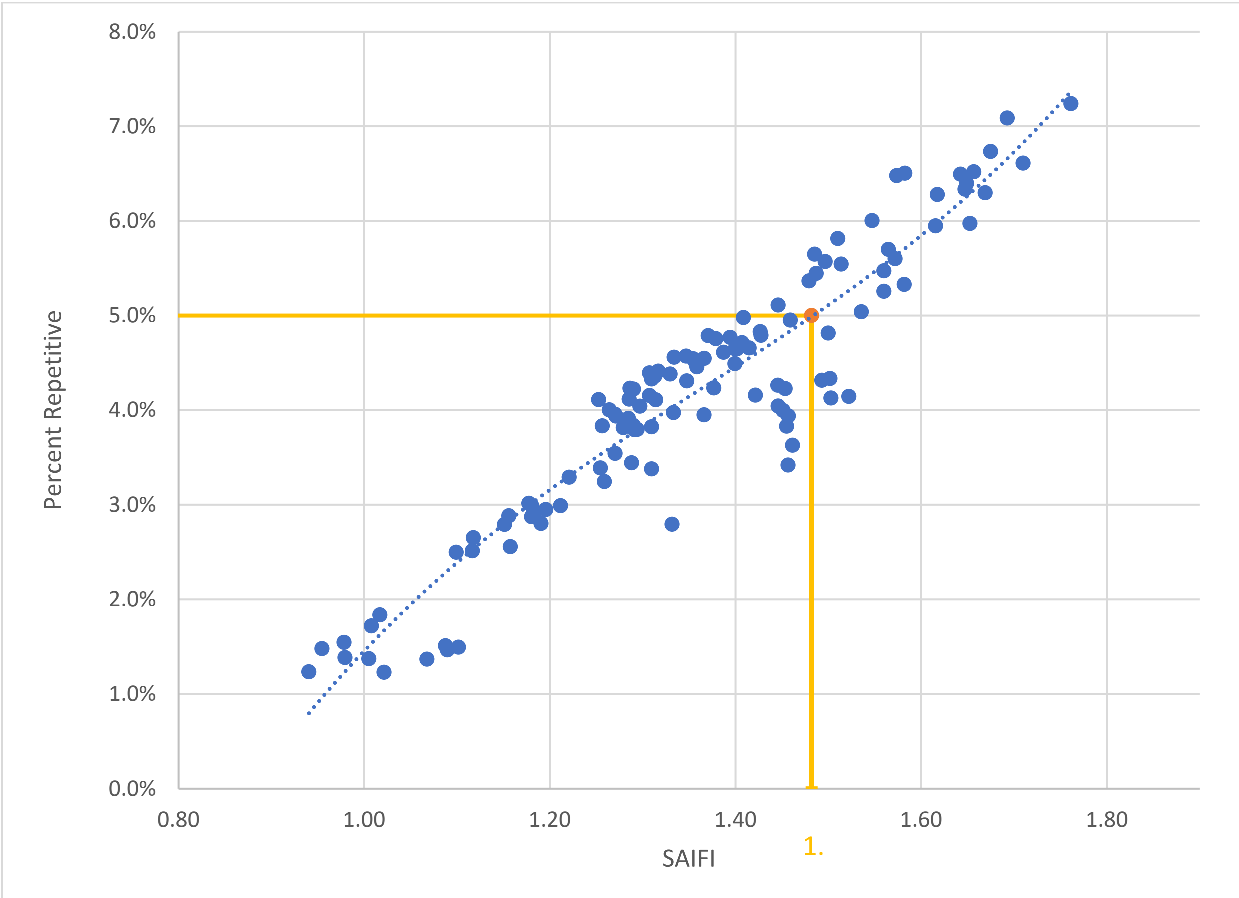
Specific projects are not developed far in advance for this sub-program. Projects may be submitted for construction during the same year and evaluated through the same layered approval process described for other capital programs. The planning process is completed closer to the time that the projects are executed so that timely data is utilized to provide the most benefit to customers. Planning these types of investments too far in advance could result in using outdated data. Further, project areas identified for proactive reliability improvements too far in advance could have system improvements completed under other capital or O&M programs in the interim.

Benefits

There is a direct correlation between SAIFI (including MEDs) and the MPSC's Repetitive Outage performance standard (which, by definition, includes storms). A statistical comparison of the two metrics, shown earlier in Figure 130, indicates that once SAIFI (including MEDs) exceeds approximately 1.45, it becomes likely that the Repetitive Outage performance index standard will not be met. To improve customer satisfaction, the Company continues to focus on sustained SAIFI performance to meet the Repetitive Outage performance standard. A deteriorating SAIFI increases the probability that more than 5% of customers experience five or more Same Circuit Repetitive Interruptions per year. By targeting investment to the worst performing areas of our system, the Company expects to improve both SAIDI and SAIFI. This improves the customer experience through reduced outage length and the frequency of outages experienced.

FIGURE 130

% OF CUSTOMERS EXPERIENCING 5 OR MORE INTERRUPTIONS IN A YEAR VS. SAIFI (INCLUDING MEDS), 2009-2020



As with the LVD Lines Reliability sub-program, targeted locations consistently see immediate benefits following an LVD Repetitive Outage project. For example, at Chapin Substation, Marion Circuit, zone 922, the recloser experienced one to four outages per year starting in 2014, causing outages for about 30 customers. In 2017, the Company added sectionalizing to the radial line. Subsequently, these customers experienced no interruptions in 2018, 2019, or 2020 due to this issue, saving approximately 7,000 customer outage minutes annually.

At Duquite Substation, Saganing Circuit, zone 336, the fuse experienced two to four outages per year starting in 2015 through 2018, causing outages for about 170 customers. In 2018, the Company relocated 1,700 feet of this circuit away from the forested area in deep ROW to the road. Subsequently, these customers experienced no interruptions in 2019 or 2020 due to this issue, saving approximately 230,000 customer outage minutes annually.

The proactive investments made to replace deteriorated assets and reduce customer exposure to outages improve employee and public safety. Furthermore, investments in the LVD Repetitive Outages sub-program reduce overall cost associated with emergent response for additional interruptions in the capital sub-program LVD Lines Demand Failures.

vii. Metro Reliability

The Metro Reliability sub-program ensures the long-term safe and reliable operation of the Company's Metro systems with investments to install and upgrade the civil and electrical assets that distribute electricity in those downtown cores. The performance goals of this sub-program are to reduce customer outage frequency (SAIFI) and reduce customer outage durations (CAIDI and SAIDI). These objectives are achieved through investments in four categories: (i) obsolete or needed civil assets; (ii) obsolete or needed electrical assets; (iii) dead fronting equipment; and (iv) mobile vaults and new technologies.

Over the next five years, the Company expects to invest between $5 million and $7 million per year in this sub-program, as shown below:

FIGURE 131

METRO RELIABILITY CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Obsolete or Needed Civil Equipment	1.5	2	2	2	2
Obsolete or Needed Electrical Equipment	0.6	0.8	2	2	2
Dead Fronting	1.5	0.8	3	2	2
Mobile Vaults	2	2	-	-	-
Total	**5.6**	**5.6**	**7**	**6**	**6**
Unit Forecast *(number of projects)*					
Investment Categories	2021	2022	2023	2024	2025
Obsolete Civil Equipment	2	1	1	1	1
Obsolete Electric Equipment	3	3	2	2	2
Dead Fronting	4	3	8	6	6
Mobile Vaults	1	1	-	-	-

In this sub-program, the Company replaces functionally obsolete equipment, including:

- Oil-insulated switches with SF_6 insulated switches;
- Polychlorinated biphenyl ("PCB") oil-insulated voltage transformers with non-PCB transformers and dead front busing well inserts; and
- Impregnated Paper Lead Covered ("IPLC") and Varnished Cambric Lead Covered ("VCLC") cable with crosslinked tree retardant polymer insulated cables.

The Company also increases equipment safety through dead fronting by replacing:

- Live-front, vault-style transformers and fusing with molded vacuum interrupters;
- Encapsulated transformer bushings (fuses and elbow type) and live secondary buss with guarded load centers;
- High rise live-front transformer replacement; and,
- Padmount live-front transformers, including transclosures.

The Company is also planning to purchase "mobile vaults" in 2021 and 2022 as a tool to facilitate more dead-fronting equipment projects and to decrease the operational response time to vault transformer outages. These mobile vaults will build on the Company's successful use of mobile substations.

Planning Process

The Company identifies Metro Reliability projects during an annual planning cycle each year. During this cycle, circuit engineers identify the most critical needs of the system to increase the integrity of the grid. While the Company continuously monitors the reliability of the Metro system, this annual review helps determine which line segments and components need to be addressed in a given year, as some projects may be large enough to span multiple years. Additionally, the Company determines which remediation strategy to use. Due to the lengthy customer interruptions that a Metro outage can cause, these projects are proactive to prevent an outage from occurring and not due to a previous interruption. Inputs the Company uses in its Metro reliability assessment include:

- **Current system condition** – Metro condition is assessed based on safety and ability to operate existing equipment;
- **Customer base** – Projects are prioritized based on reliability benefits to each customer category, with highest priority for critical customers, followed by large residential customers, and then other commercial and residential customers; and
- **Efficiency gains with other projects** – When the Company receives external requests, particularly for Metro New Business and Metro Asset Relocations, the Company may also perform Metro Reliability work at the same time.

Further details on the criticality and priority of customers are as follows:

1. Critical customers are highest priority due to the negative impact an interruption could have to the community. Examples of these critical customers include, but are not limited to, water supply, sewage facilities, hospitals, and public safety.
2. Large residential customers – approximately 50 customers or more – are the second priority, to reduce the number of customers interrupted by a single outage.
3. Other commercial or residential are the final category of customer priority. This includes, but is not limited to, offices buildings, smaller residential (e.g., less than 10 customers), and store fronts.

For projects that require new or modified civil infrastructure, the Company releases the scope to a contracted civil engineering firm, who creates a feasibility study for a civil infrastructure path. The feasibility study provides several options for possible routes and estimated construction costs for those options. The Company's Metro engineering planner reviews the feasibility study with operations representatives to determine ease of construction and impact to future electric operations. The Metro engineering planner notifies the civil engineering firm, who will prepare a design based on the selected option. The Metro engineering planner will prepare an electrical design, cable pulling schedule, and electrical bill of materials. The civil engineering firm delivers the design and any documents needed to obtain a permit to perform work in the ROW from the municipality or MDOT, including a detailed traffic control plan.

Risks that may be encountered during construction of Metro Reliability projects include:

- Encountering crushed conduit while attempting to replace cable. Conduit can be crushed as a result of heavy loaded objects above the ground or the fiberglass becoming brittle as a result of exposure to soil conditions.
- Increased costs associated with temporary transformation and other items required for a mobile vault. This is similar to the use of a mobile substation to allow for safe maintenance or construction work on de-energized equipment. It has a set of padmounted equipment built at grade level and fenced off to guard from the public.
- Potential fluctuation in contractor costs. Contractor costs can fluctuate between projects based on the bids received. This is based on the amount of work that the contractor already has secured and the cost for them to add this to their work plan (additional or mobilizing resources).

<u>Examples</u>

In 2021, the Company is investing in a project in Kalamazoo. Multiple objectives were approved in the concept including:

- Dead front and modernize the existing Crescent Engraving Vault at the corner of Church St. and Kalamazoo Ave (see current live front in Figure 132 below);
- Reinstall transformation to provide service to the fire pump at the new Justice Facility across the street, and new transformation to new Company-owned streetlighting around the blocks occupied by the new Justice Facility and existing Kalamazoo County administration building;
- Install new civil infrastructure in the Church Street ROW to feed the new fire pump service, streetlighting and future infill redevelopment sites on Eleanor St; and
- Re-establish a primary loop severed during the construction of a hotel in 2019.

FIGURE 132

CURRENT LIVE FRONT CRESCENT ENGRAVING VAULT

Benefits

Metro Reliability investments minimize potential adverse impacts on customer experience by improving overall reliability and operation. These proactive investments also improve employee and public safety, through reduced outage incidents. Furthermore, investments in the Metro Reliability sub-program reduce overall cost associated with emergent response in the capital sub-program Metro Demand Failures.

viii. HVD Lines and Substations Rehabilitation

The HVD Lines and Substations Rehabilitation sub-program supports the capital repair or replacement of 46 kV and 138 kV lines and substation equipment to address issues where failure has not yet occurred, but is imminent, to maintain reliability. Work in this sub-program was historically performed in the HVD Lines and Substations Demand Failures sub-program, and this sub--program includes the same five investment categories as the HVD Lines and Substations Demand Failures sub-program.

This sub-program includes some large “planned” investments that are identified and planned far in advance. However, it also includes some “emergent” investments as well. This sub-program includes work to address imminent failures that were historically included in the HVD Lines and Substations Demand Failures sub-program; this work to address imminent failures takes place in rapid response to anomalies that are identified on the system as they arise during inspections or through other means, as discussed below. As such, projects are not identified far in advance for all spending in this sub-program. Instead, some investment levels in this sub-program are projected based on historical spending levels on imminent failure projects, in a manner similar to Demand Failures.

The Company plans to spend between $39 million and $56 million per year in this program over this five-year plan, in line with historical spending in this category and the addition of the proactive replacement of two HVD transformers per year and the rebuild of half of two HVD substations per year. The program consists of the planned activity in the table below as well as the costs associated with the unplanned needs of our system.

FIGURE 133

HVD LINES REHABILITATION CAPITAL INVESTMENT

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Pole Replacements	5.7	6.0	6.3	6.7	6.7
Pole Top Assembly Replacements	1.8	1.8	1.8	1.8	1.8
Switch Replacements including MOAB	1.9	1.9	1.9	1.9	1.9
Miscellaneous Other Replacements	0.6	0.6	0.6	0.6	0.6
Total	**10.0**	**10.3**	**10.7**	**11.0**	**11.0**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Pole Replacements	261	275	289	307	307
Pole Top Assembly Replacements	296	296	296	296	296
Switch Replacements including MOAB	39	39	39	39	39
Miscellaneous Other Replacements	7	7	7	7	7

FIGURE 134
HVD SUBSTATIONS REHABILITATION CAPITAL INVESTMENT

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
HVD Substation Rebuilds	21.4	21.8	31	36	36
HVD Substation Transformer Replacements	3.6	3.9	4.1	4.1	4.1
Imminent Substation Equipment Replacement	4.0	4.7	4.9	4.9	4.9
Total Spending	**29.0**	**30.4**	**40.0**	**45.0**	**45.0**

The types of work in each of these investment categories are the same as the types of work in their corresponding investment categories in the HVD Lines and Substations Demand Failures sub-program. The difference is that this sub-program deals with imminent failures, rather than actual failures.

a) HVD Lines Rehabilitation

Planning Process

The Company determines work needs in this sub-program based on real-time HVD line component anomalies, assessing them by severity or risk to the system. The most urgent HVD line component failures are those resulting in customer outages, making them immediate action items. These are addressed in the HVD Lines and Substations Demand Failures sub-program.

As discussed in the section on the HVD Lines and Substations Demand Failures sub-program, some component failures do not cause a line to trip but decrease the integrity of the line and usually increase the risk that the line will trip or fail in the future. As these are identified, the Company assigns such component failures a priority and generates orders for the repair or replacement of the component in a time frame consistent with the risk posed.

Regular inspection of equipment helps determine if assets need repair or replacement, ensures components will operate as intended when called upon, and maximizes the value of those assets over their lifetimes. Equipment near the end of life can be replaced before it fails. Such inspections and replacements are more economical, safer, and can save customer outage minutes.

The table below shows the four priority levels and the guidelines for repair timelines. Priority 2 and Priority 3 anomalies are included in this program.

FIGURE 135
HVD SYSTEM PATROL FINDINGS CRITERIA

Priority	Description	Repair Timeline
1*	Imminent Failure	24 hours
2*	Highly Likely Failure	5 to 10 days
3*	Likely Failure	4-6 months
4	Monitor	Repair not required but condition tracked
*SAP repair orders are created for all Priority 1, 2 and 3 findings only		

Inspection and evaluation of HVD lines allows the Company to identify equipment near the end of life so that it can replace those items before they fail and cause an outage to customers or reduce system operability. Such inspections and proactive replacements are more economical, safer, and can save customer outage minutes compared to responding to an actual failure. The Company has four key inspection programs for HVD lines:

Pole Inspection Program

HVD poles are inspected on a 12-year cycle. Depending on how urgently a pole replacement is needed, the replacement may take place in this program or in the HVD Lines Reliability sub-program. A contractor performs visual inspections, sonic inspections and bore testing on all poles that are 11 years old or older along line sections specified by the Company. The contractor tests poles from the ground line to six feet above the ground line. If the sonic test indicates decay, visual decay, or insects present, a bore test is performed, and the shell thickness is recorded. For poles indicating decay or voids near ground level, a bore test is performed at 45 degrees or below the ground line. Poles with a shell thickness less than the standard depending on the pole circumference, as shown in Figure 136 below, are recommended for replacement and receive a red tag. Poles with ground line surface decay that reduces the original circumference by 2” or more or with internal decay or with insect infestation are treated with wood preserving products. Red tagged poles are not treated with wood preserving products.

FIGURE 136
BORE TEST CRITERIA TO IDENTIFY WOOD POLE REPLACEMENT CANDIDATES

Wood Pole Bore Test Criteria		
Original Ground Line Circumference (Inches)	Reduction in Ground Line Circumference due to Exterior Decay (Inches)	Minimum Shell Thickness (Inches of Solid Wood)
25 -34	0 – 3	2.00
	Over 3 – Replace	-
34 -39	0 – 3	2.50
	3 – 4	3.00
	Over 4 – Replace	-
39- 45	0 – 3	3.00
	3 – 4	3.50
	Over 4 – Replace	-
45 -55	0 -1	3.00
	2 – 4	3.50
	4 – 5	Solid Heart
	Over 5 – Replace	-
55 - 65	0 – 3	3.50
	3 – 6	Solid Heart
	Over 6 – Replace	-

Notes:
Column 1: Original ground line circumference when installed.
Column 2: Reduction in ground line circumference after scraping away decayed wood.
If the reduction in ground line circumference falls into a range in Column 2, there must be at least the amount of solid shell wood that is listed Column 3.

Visual inspection can be used to identify rejected poles where there is severe decay at the top of the pole or where the pole is split or has large voids above chest height or other similar conditions. The Company may elect replacement in case of severe decay at the top of the pole following visual inspection.

Helicopter Inspection Program

Helicopter inspections, as discussed in the HVD Lines and Substations Demand Failures sub-program section, are a significant source of information to determine immediate action items. For example, a flight conducted with a corona camera identified an insulator on a 46 kV line that was emitting a corona signature, prompting a Priority 2 replacement of the insulator to avoid a potential outage to the line and customers.

FIGURE 137

SCREENSHOT FROM CORONA CAMERA SHOWING INSULATOR WITH CORONA SIGNATURE

Ground Patrol

For safety reasons, helicopter inspections cannot fly over approximately 400 miles of the HVD system, because it is difficult to land quickly and safely in the event of an emergency. Most of these "no-fly lines" are in urban areas. To inspect these lines, the Company completes ground patrols at least biannually, which includes IR and/or corona inspection using handheld cameras. A drone may be used to get a closer look at pole tops to help prioritize the anomaly.

MOAB Testing

MOABs allow the Company to sectionalize HVD lines and restore a portion of the customers who would otherwise be affected by a line outage. The controls of the MOABs require power to operate, and since they operate when the line loses power, batteries provide control circuit power. Periodic battery replacement ensures that power is always available to operate the device. MOABs are tested annually to ensure they are in proper working order and the batteries are as needed. During this testing, broken or damaged switches are sometimes identified and replaced under this program.

FIGURE 138
TYPICAL 46 KV MOAB SWITCH

Project Prioritization and Selection

Inspection and evaluation of HVD substations allows the Company to identify equipment condition so that items can be replaced, if needed, before they fail and cause an outage to customers or reduce system operability. Some equipment (power transformers, station batteries, gas circuit breakers, and transformer bushings) are monitored by Field Technical Services and Substation Reliability Engineers and are replaced prior to failure through this sub-program. Some imminent failures are identified through monthly visual patrols performed by the Company's Substation Operations group and are replaced through this program prior to failure.

As already discussed, prioritization and selection for HVD Lines Rehabilitation projects is "emergent" in a similar manner to Demand Failures projects.

b) HVD Substations Rehabilitation

Planning Process

For the replacement of substation components at imminent risk of failure, projects are identified as the Company identifies anomalies through its HVD substation inspection cadence, as discussed in the section on the HVD Lines and Substations Demand Failures sub-program. While that sub-program responds to actual failures, this sub-program responds to lower priority P2 through P4 anomalies.

For HVD substation rebuilds a list is developed to collect data on a variety of substation condition parameters including the original substation construction date, known operational concerns, known reliability concerns, known System Protection issues, known maintenance concerns and known controls concerns. These concerns are then entered into a matrix and ranked creating a short list of rebuild candidates. The list is then vetted against potential construction barriers, conflicts (other construction projects, line rebuilds, METC projects, etc.) and geographic location. The top candidates are then added to the rebuild schedule.

For HVD substation transformer replacements, potential candidates are identified and ranked based on age, condition (gassing and maintenance history), risk, substation configuration and geographic location. The top candidates are then added to the replacement schedule.

Timing

For the replacement of substation components at imminent risk of failure, in if an HVD substation equipment anomaly is causing an outage to customers or if its potential failure poses an immediate and intolerable electric system operating condition, it will be addressed immediately through the HVD Lines and Substations Demand Failures sub-program. If the equipment anomaly is not currently causing a customer outage or its potential failure poses a nominal electric system operating condition, it will be addressed at a future point in time through this sub-program, or alternatively through the HVD Substations Reliability sub-program. Projects with longer lead times may be delayed if other replacements are identified that are determined to have a higher risk of failure or have failed in service.

The Company has approximately 120 HVD substations that transform 138kV power from the METC grid to the CE 46kV system, forming the backbone of the Company's distribution system. The oldest of these stations were built in the 1920's and are approaching 100 years in age, well beyond their expected design life. 20% of these substations were built prior to 1951. While certain components have been updated since these substations have been erected, the oldest HVD transformers still in use date back to 1945, and in any case, many components have not been updated. The vast majority of insulators, bus work, structural steel, control enclosures, fences, and other components in these substations are original equipment that cannot be expected to last forever. A comprehensive program to rebuild or replace these substations will ensure that these locations will still be available to serve customers well into the future. If two of the oldest substations are rebuilt per year for the next 14 years, by the year 2035 the Company will still have HVD substations that are 85 years old. Prioritizing the order in which stations are to be rebuilt is detailed in the above "Planning Process" section.

For HVD substation transformer replacements, the process for prioritizing the order in which HVD transformers are replaced is detailed in the "Planning Process" section, above and is primarily condition-based. The transformer replacement process is coordinated with the HVD substation rebuild process such that transformers that are identified as approaching end of life in stations that are scheduled to be rebuilt may be replaced prior to the rebuild if it is prudent to do so.

Benefits

This sub-program addresses areas on HVD lines and in HVD substations where failures, and corresponding outages and customer interruptions, are particularly likely. Addressing degrading equipment reduces the likelihood of failure. This is particularly important in this sub-program, as outages on the HVD system often result in a high number of customer interruptions.

ix. LVD Substations Rehabilitation

The LVD Substations Rehabilitation sub-program includes capital repair or replacement of LVD substation equipment that has not actually failed, but that has been assessed to be at imminent risk of failure. Much of this work was formerly included in the LVD Substations Demand Failures sub-program, but now takes place in this newly created sub-program as discussed earlier in the Demand Failures section of my direct testimony. The LVD Substations Rehabilitation sub-program also includes work that was formerly included in the LVD Substations Reliability sub-program, including projects to address working clearance code violations, replacement of 138 kV SOGS and 138 kV fuses with a three-phase interrupting device, and replacement of obsolete equipment. Obsolete equipment includes reclosers, breakers, fuses, regulators, lightning arrestors, and switches that can no longer be purchased from manufacturers, and with depleting inventory and replacement parts.

LVD Substation Rehabilitation projects generally consist of the following types of investments:

- Replacing equipment/components degrading toward imminent failure;
- Replacing structural components degrading toward imminent failure;
- Replacing equipment/components that have been identified to have excessive failure rates;
- Replacing equipment/components that are obsolete; and
- Replacing equipment/components that do not meet regulatory standards or requirements.

The scope of the Company's five-year plan is shown below and includes the following:

- Replacing 15 to 16 Allis Chalmers transformers in LVD substations from 2021 – 2024, and the last seven Allis Chalmers transformers in 2025;
- Three to four control house working clearance program projects, replacing obsolete equipment and replacing equipment degrading toward imminent failure; and
- Replacing three to five transformers degrading toward imminent failure.

FIGURE 139

LVD SUBSTATIONS REHABILITATION CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Allis Chalmers Substation Transformer Replacements	9	9	9	9	4
Equipment replacement and regulatory	3.5	2.5	2.5	2.5	2.5
Transformers at imminent risk of failure	2	2	2	2	3.5
Total	**14.5**	**13.5**	**13.5**	**13.5**	**10**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Allis Chalmers Substation Transformer Replacements	16	15	15	15	7
Equipment replacement and regulatory	14	10	10	10	10
Transformers at imminent risk of failure	3	3	3	3	5

Allis Chalmers Transformer Replacements

Allis Chalmers mid-20th century vintage substation power transformers were produced with a design deficiency associated with the top clamping structure of the transformer windings. The key purpose of the clamping structure is to prevent winding movement. This deficiency results in an inherent weakness of the transformer to withstand the forces accompanying certain magnitude low side faults. Winding movement typically results in electrical shorts and arcing, which lead to excessive heating, creation of combustible gasses, and eventual failure of the transformer. Figure 140 below shows an Allis Chalmers transformer failure at Gladwin Substation. Note the two bulged and deformed failed lower windings on the left and middle phases.

FIGURE 140

ALLIS CHALMERS TRANSFORMER FAILURE

The Company purchased approximately 209 Allis Chalmers units with this design deficiency between approximately 1936 and 1970. After studying this issue, in 2016 the Company established a replacement plan to mitigate future failures and interruptions to customers. Allis Chalmers replacements are prioritized based on dissolved gas analysis ("DGA") and IR measurements, particularly looking at those with General Electric (GE) type U bushings and the ability to take the bank out of service based on customer and system impact. The GE type U bushings are an influencing factor as they are known throughout the industry to have a high failure rate. By the end of 2021 there will be approximately 40 units of the original design and another 12 rewound units considered at risk of developing the condition, for a total of 52 units still in-service at 50 LVD substations.

The deficiency and reliability risk of these Allis Chalmers transformers is well documented and understood. Substation transformer failures are long in duration (8-16 hours) and impact an average of 2,500 customers, representing approximately 0.6 to 1.3 SAIDI minutes per failure. Additionally, substation transformers are long lead-time items, which take approximately 10–12 months to procure. The high customer impact and unit long lead time coupled with the propensity of continued degradation from exposure to normal low side faults creates a necessity to expedite replacement of these Allis Chalmers transformers.

<u>Planning Process</u>

Most work in this rehabilitation sub-program is proactive to prevent equipment failure and customer outages. Imminent failures are identified by monitoring and tracking LVD substation equipment and components utilizing various means of analysis such as DGA and IR data. These analyses help to identify specific locations to target corrective action based on probability of an unplanned event, and to prioritize projects that will deliver the greatest reliability impact based on specific metrics (e.g., SAIDI and SAIFI). Proactively replacing deteriorated equipment that is deemed as an imminent failure in advance of an actual equipment failure is more economical as it typically avoids customer outages and costly overtime.

Some imminent failures are identified through monthly visual patrols performed by the Substation Operations group and are replaced through this program prior to failure. The cadence of the LVD substation equipment evaluation and inspection is found in Figure 141 below. Input from operating organizations and other departments inform the substation planning engineers with operational concerns and system constraints that may trigger a need for projects to resolve working clearance code violations and replacement of obsolete equipment.

FIGURE 141

LVD Substation Inspection Cadence		
Inspection Task	**Cadence**	**Actions Taken**
All Station Components	Bi-Monthly	Visual inspection Routine patrol inspections
Entire Substation	Bi-Annually	Infrared inspection of entire substation
Protective Relays and Communication Systems	Dependent on relay model & failure history	Maintenance & testing performed
Station Batteries	Monthly	Voltage check
	Annually	Equalization
	Annually	Specific gravity reading
	4 Years*	Complete inspection
Power Transformers	Bi-Monthly	Visual inspection (including fans and pumps)
	Annually	Total combustible gas test (follow-up dissolved gas analysis tests, if warranted)
	Annually	Diagnostic Dissolved Gas Analysis of Load Tap Changer Oil (Transformers with Load Tap Changers Only)
	Bi-Annually	Diagnostic Dissolved Gas Analysis of Transformer Main Tank Oil (Transformers with Load Tap Changers Only)
	6 years**	Diagnostic dissolved gas analysis of transformer oil (Non-Load Tap Changer Transformers)
	Annually	Test Operated (decoupled)

Motor Operated Air Break Switches (MOABS)	4 Years**	Battery replacement
Single Phase Regulators	9 Years***	Limited program of dissolved gas analysis
*Or periodically as needed **Or sooner if determined by combustible gas tests or high gas levels in previous tests ***Started in 2014		

Allis Chalmers substation transformer replacements take place on a more proactive basis, rather than necessarily waiting for an imminent failure, but the Company still prioritizes replacements to address the most at-risk transformers first. IR inspections are the best way to detect when excessive heat, the leading indicator of this type of failure, begins to manifest. The condition is indicated by a warmer band typically registering in the lower one-third of the transformer tank. The Company performs an IR inspection annually on all Allis Chalmers transformers.

FIGURE 142
IR PHOTO OF FAILED TRANSFORMER

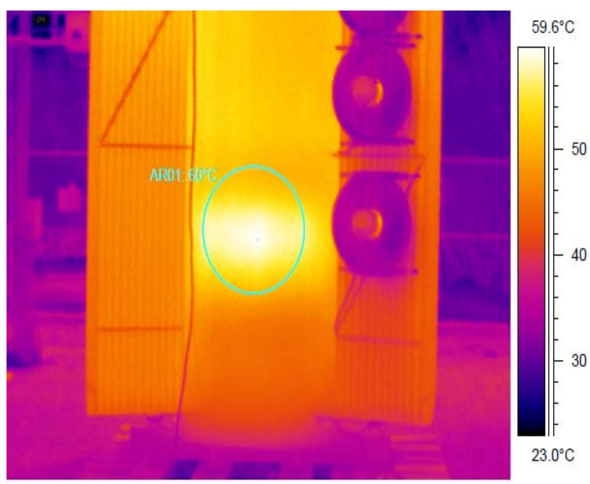
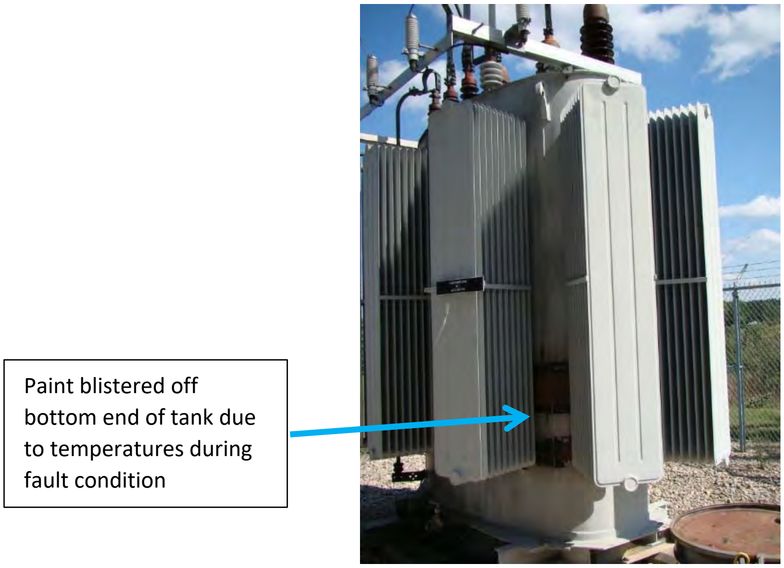


FIGURE 143

FAILED TRANSFORMER



When the IR inspection detects a heating band indicating development of this condition, the units are put on a quarterly DGA monitoring schedule and they are given higher priority for replacement consideration based on the analysis of both the DGA and IR together.

In the "equipment replacement and regulatory" investment category, when a substation is at the end of its useful life and experiences substantial deterioration – becoming unsafe, no longer able to reliably operate, or some other issue – the Company may elect to rebuild the substation. For regulatory-related projects, the Company is planning projects related to working space, which bring substations into compliance with NESC Rule 125, section A, titled "Working space about electric equipment: Working Space (600 Volts or Less)." When the Company was working to upgrade its telecommunications at its LVD substations in the late 2010's, it discovered that some of the substations did not meet the NESC working space requirements and began a process of addressing all of these working space issues by 2028.

<u>Project Prioritization and Selection</u>

The Company identifies imminent failure projects by monitoring and tracking substation equipment via visual inspections, DGA, and IR recordings, and prioritizes projects to proactively address replacement of deteriorating equipment as identified. Additionally, the Company considers replacement based on known industry equipment/component defects and trend data that indicates degrading equipment condition.

Projects that have been identified as imminent failure are monitored and re-prioritized into the schedule to address immediate needs. Equipment and components that have been identified as prone to failure may be included in other substation capacity and reliability projects to maximize efficiencies and avoid additional crew deployments and mobile substation sets.

Priorities can change over time. For example, transformer replacement projects at Fennville, Martin, and Delton were brought forward into 2017 based on a concern of imminent failure, and the Watkins, Cooley, and Portage transformer replacement projects, which were less urgent, were delayed into 2018 to accommodate advancement of these projects.

Benefits

Maintaining adequate substation equipment, material inventories, and mobile substation fleet to promptly replace failing equipment minimizes the impact on customer outage minutes. Addressing degrading equipment allows the Company to avoid the potential of long-term outages and restoration delays. This helps improve reliability, as shown in the Allis Chalmers example above. In addition, by replacing or rehabilitating equipment before failure, it reduces unit cost.

x. LVD Lines Rehabilitation

The LVD Lines Rehabilitation program includes capital repair or replacement of LVD lines equipment that has not actually failed, but that has been assessed to be at risk of failure in the near term. This work was formerly included in the LVD Lines Demand Failures sub-program.

This sub-program consists of two investment categories: i) security assessment repairs, and ii) imminent rehabilitation. The imminent rehabilitation investment category was formerly known as “emergent rehabilitation.” Investments in this sub-program are balanced between planned and demand/emergent work. The project completion schedule needs to remain flexible to accommodate imminent failures as they are identified, which means that projects are often subject to reprioritization as new information emerges, particularly in the imminent rehabilitation investment category.

The Company projects investment for imminent rehabilitation work based on historical spending and expected rehabilitation costs; therefore, the Company expects that needed investment will increase to address underground and overhead anomalies due to system deterioration. The Company’s five-year investment plan for this sub-program is as follows:

FIGURE 144

LVD LINES REHABILITATION CAPITAL INVESTMENTS

5-Year Capital Plan (all values in $ millions)					
Investment Categories	2021	2022	2023	2024	2025
Security Assessment Repairs	26.9	42.0	42.7	43.5	43.9
Imminent Rehabilitation	10.3	11.7	11.9	12.1	12.3
Total	**36.2**	**53.6**	**54.6**	**55.6**	**56.2**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Security Assessment Repairs	223	335	365	365	365
Imminent Rehabilitation	643	795	709	709	709

The imminent rehabilitation category addresses emergent issues that arise in which an actual failure has not occurred, but in which repair or replacement is required. Imminent rehabilitation projects deal with conditions identified outside of inspection cycles and normal planning work, but when there is not an immediate need for repair as with LVD Lines Demand Failures projects. These address the following issues:

- P3 and P4 Overhead Prioritization Codes – P3 and P4 conditions, as identified in Figure 145 below, may be addressed in this investment category when found outside of the inspection process;
- Underground Cable Repair – If this section or area has experienced multiple faults or the vintage of the cable warrants replacement, a project is developed to replace the faulted section of cable and in some cases, adjacent sections of cable as well;
- Underground Padmount Equipment – Padmount equipment may require relocation or replacement due to ground shifting that causes leaning or sinking; and
- Underground Padmount Equipment Inspections – Every year, padmounted equipment is visually inspected around the exterior for any signs of oil leaking or holes that expose electrical components. When found, the equipment is replaced, and any environmental issues are mitigated.

For security assessments, the Company inspects approximately 300 overhead circuits for this category annually. Based on the results of these security assessments, the Company identifies anomalies that must be repaired based on priority codes, discussed below. This category addresses issues that the Company discovers during LVD overhead line inspections. The LVD overhead line inspection category is completed on a six-year cycle. The overhead line inspection category evaluates all equipment on a structure, including the pole, through a visual inspection process. The circuits are assessed by completing driving inspections to identify public safety hazards along with failed, end-of-life, defective, and obsolete equipment.

During the security assessment, prioritization codes are used to classify issues and determine how quickly they must be addressed. As discussed in LVD Lines Demand Failures, P1 and P2 issues are addressed within that sub-program. Figure 145 below presents the types of hazards, which are Priority 3 (“P3”) and Priority 4 (“P4”), found during security assessments. The hazards are listed by the priority code for the anomaly. The Company strives to address P3 and P4 issues within two years.

FIGURE 145

LVD SECURITY ASSESSMENT HAZARD CODES

Code	Description
P3 – Failure Expected Before Next Inspection (Less Than 6 Yrs)	
P3A	Pin Pulling from Crossarm / Pole
P3B	Cracked Crossarm
P3C	Broken Guy – Leaning Pole
P3D	Pole: Damaged
P4 – Heightened Risk of Failure	
P4A	Broken/Missing Crossarm Braces
P4B	Failed Arrester
P4C	Broken Guy – Non-Leaning Pole
P4D	Damaged Equipment (Transformers, Reclosers, Etc.)
P4E	Lightning/Flashover Burn Marks
P4F	Poorly Sagged Line
P4G	Pin Through Crossarm

<u>Planning Process</u>

The Company collects imminent rehabilitation data primarily through the Field Operations organization. For example, Field Operations may have frequently visited a location to restore service for a failed underground cable in the same subdivision. This team relays this information to circuit planners so they can investigate and create a concept project for a full replacement of the underground cable and possibly live front transformers or padmounted switching equipment in that subdivision if necessary.

As discussed previously, the security assessment program is balanced to allow for one-sixth of the system to be assessed annually. This results in approximately 9,000 miles assessed annually.

Project Prioritization and Selection

Imminent rehabilitation projects are generally not planned far in advance in this investment category, because the investment category is meant to quickly respond to system anomalies and customer interruptions that have already taken place. These projects may be reprioritized as information evolves.

Security assessment projects are submitted following the completion of the assessment for consideration in a future year. The security assessment projects are completed in order of oldest inspection first.

Benefits

While the LVD Lines Demand Failures sub-program addresses situations in which equipment has already failed, the LVD Lines Rehabilitation sub-program and its funding are essential to address imminent failure conditions that could result in interruptions to customer(s) or create unacceptable system operating conditions, and therefore provides a reliability benefit by reducing the likelihood of future actual failures. Because these investments are planned and targeted at areas of the system most likely to fail, they reduce outage frequency. By replacing or rehabilitating equipment before it fails, work can be completed in a more economical manner.

xi. Metro Rehabilitation

The Metro Rehabilitation sub-program addresses assets on the Company's Metro systems that have been identified as being at a high risk of imminent failure, such that replacement is justified based on potential risks to public safety, employee or contractor safety, or to maintain the reliability of the Metro systems. Work in the Metro Rehabilitation sub-program was historically done in the Metro Demand Failures sub-program. The Metro Rehabilitation sub-program consists of two investment categories: (i) crushed duct replacements; and (ii) vault or manhole rehabilitation. The Company also budgets a small amount of money for miscellaneous work.

When an existing duct bank has been crushed or is deteriorated, it is replaced with a new concrete-encased duct bank. New cable must also be run through the new duct bank to replace the damaged cable. Vaults or manholes require replacement of the entire structure – or portions of the structure, such as an existing roof – that is damaged or deteriorated. This situation creates safety hazards to the public passing over it and anyone entering the structure.

The Company plans to invest between $4 million and $6 million in this sub-program each year over the next five years, as shown below:

FIGURE 146
METRO REHABILITATION CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
Crushed Duct Replacements	3	2.5	3	3	3
Vault or Manhole Replacements	1	2.1	2.7	2.7	2.7
Miscellaneous	0.4	0.0	0.3	0.3	0.3
Total	**4.4**	**4.6**	**6**	**6**	**6**
Unit Forecast					
	2021	2022	2023	2024	2025
Crushed Duct Replacements	4	4	4	4	4
Vault or Manhole Replacements	5	4	4	4	4

Planning Process

The Company identifies Metro Rehabilitation projects during the same annual planning cycle each year that is used to identify Metro Reliability projects. As projects are identified during this annual planning cycle, they are placed into one sub-program or the other based on the type of work needed, since the two sub-programs have different investment categories from one another.

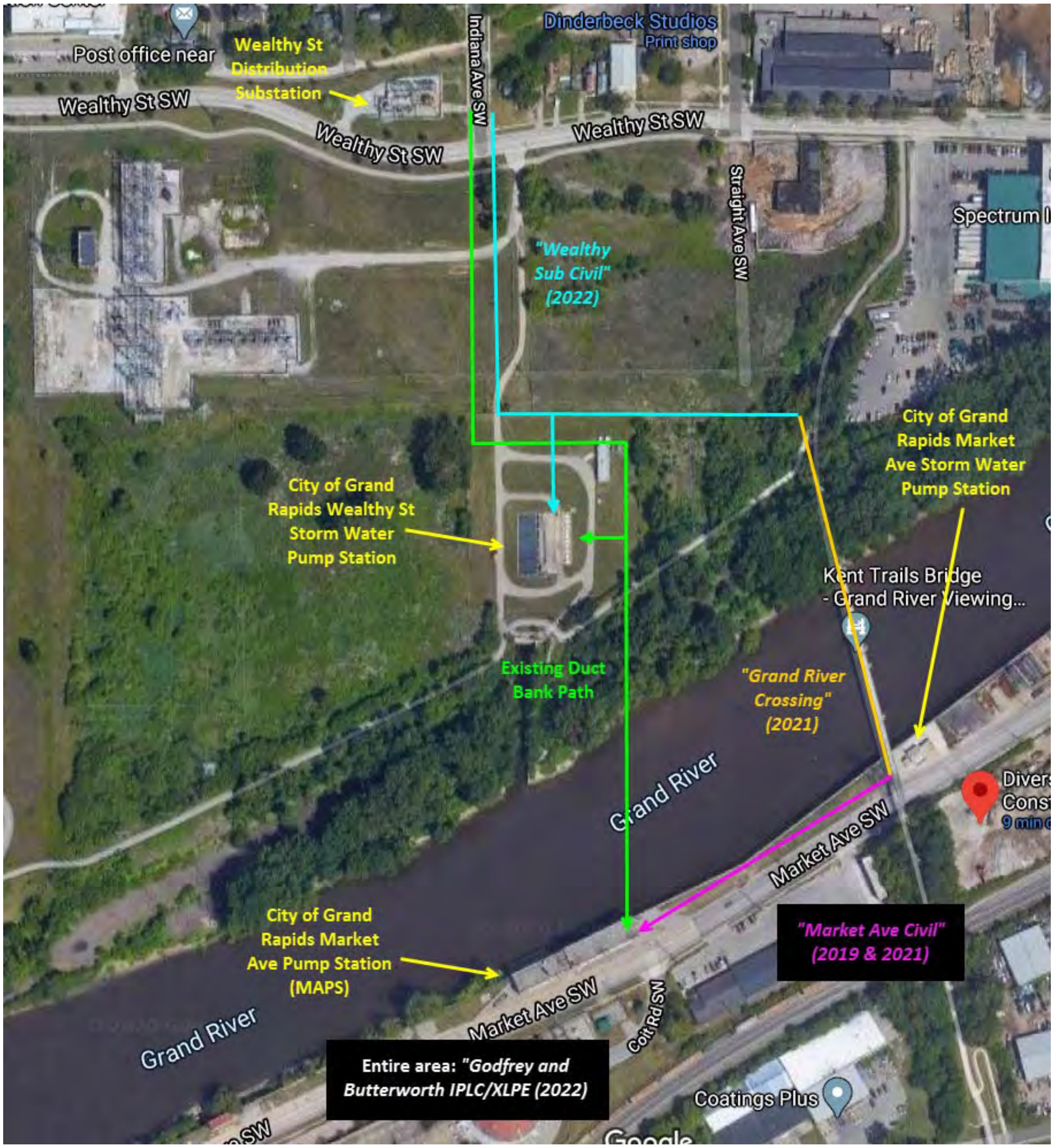
Examples

Starting in 2019, the Company invested in a multi-year Metro project to address a failing Metro duct under the Grand River that provides service to critical City of Grand Rapids public works facilities in the area. An illustration of this project is shown in Figure 147 below. Multiple objectives were approved in the concept including:

- Build new Metro duct in Market Avenue from the Grand Rapids Market Avenue Pump Station to the former Michigan Central Railroad Bridge, which is now the Oxford rail trail (2019);
- Attach the duct bank to the underside of the Oxford rail trail bridge using the bridge attachment method and standard (2021);
- Build new Metro duct from the north side of the Oxford rail trail bridge to the Wealthy Street Storm Water Pump station and to the Wealthy Street Distribution substation (2022); and
- Install new distribution cable and switchgear re-establishing the Godfrey and Butterworth circuits back to normal operation.

FIGURE 147

GRAND RAPIDS MARKET AVENUE CIVIL INFRASTRUCTURE REHABILITATION PLAN



Benefits

Upgrading and replacing degraded components in the Metro system allows the Company to maintain a redundant system in the downtown areas of cities, providing a reliability benefit. This benefit directly impacts courthouses, jails, municipal offices, police and fire departments, as well as many businesses and residents. A Metro system in good condition allows employees and contractors to work in a safe environment and supports public safety. Investing in the Metro system to alleviate failure conditions allows customers not to be single sourced as the Company isolates manholes and vaults for repair.

xii. Grid Storage

Grid Storage is a sub-program that supports the Company's battery strategy. The capital expenditures in the Grid Storage sub-program will fund the deployment of new batteries on the Company's electric distribution system.

The Company's five-year investment plan in this sub-program is as follows:

FIGURE 148

GRID STORAGE CAPITAL INVESTMENTS

5-Year Capital Plan (all values in $ millions)					
	2021	2022	2023	2024	2025
Cadillac Solar Battery	0.8	0.1	-	-	-
Airpark Portable Battery	4.4	-	-	-	-
Armstrong Islanded Battery	0.6	1.3	8.3	0.1	-
Distribution Automation Battery	0.1	8.7	1.2	-	-
Other Battery Projects	0.1	-	0.5	9.9	10
Total	**6**	**10**	**10**	**10**	**10**

The Company's battery strategy is informed by two industry trends. First, the Company expects that the capital costs for battery installation will continue their downward trend for the next several years, eventually becoming a critical part of the Company's electric supply portfolio. Second, intermittent renewable generation is expected to increase its penetration on the grid, particularly solar generation. As solar generation becomes a larger part of the generation mix, it introduces challenges related to intermittency and timing; batteries can help smooth out the intermittency of solar generation and can store electricity generated by solar facilities at off-peak times for discharge during peak times. The Company's 2018 IRP proposed a significant build-out of distributed solar generation, and the Company's 2021 IRP builds upon the Company's commitment to this solar build out. As solar penetration increases, it will eventually be necessary to invest in battery storage on a larger scale to appropriately manage the grid. In the meantime, the Company has been investing in smaller deployments of battery storage to test battery capabilities and develop Company expertise at operating battery systems to maximize and deliver the numerous value streams of battery storage to customers.

In addition to developing general battery deployment and operations capabilities to allow the Company to accommodate more solar generation on the system in the future, batteries also have potential NWS applications. Batteries may allow the Company to defer capacity upgrades on the distribution system. They may also provide islanding capabilities and otherwise improve reliability and resilience. Battery development is a crucial part of the Company's strategy for developing NWS capabilities.

Planned Projects

To build upon the Company's learnings from Parkview and Circuit West, the Company is planning three additional battery projects to develop further capabilities. The first of these= will involve a battery paired with a solar farm under development in Cadillac. This battery will be connected to the DC side of the inverter at the solar farm, which will give the Company the ability to make the solar generation dispatchable and to engage in direct smoothing of the solar generation profile. In addition to these capabilities, this battery will be more efficient in operation than the Parkview battery, which is connected to the AC side of the inverter and therefore more separated from its corresponding solar farm. Contracts with the battery integrator and construction contractor were executed in June and August of 2020, respectively. Site construction began by mid-October 2020. The battery, inverter, and all the associated major equipment have been procured, and commercial operation is expected to begin in May 2021.

The second project will deploy a portable battery on the distribution system. The primary purpose of this battery will be to defer a projected substation capacity upgrade. By connecting to the substation, the battery will provide peak load shaving to extend the life of the substation, providing an NWS to defer a substation upgrade. If the substation experiences continued load growth, and the capacity upgrade is needed in a future year, then the portable nature of the battery would allow it to be transported and connected to the distribution system at a different location, providing similar and continued benefits to customers. This battery will also provide lessons learned applicable to the broader deployment of DAUD batteries, which have the potential to be selected in a future IRP. The battery integrator contract was executed in August 2020. The property acquisition for this battery site was completed in September 2020. Construction began at the site in February 2021 and will continue through April 2021, when all major components will be delivered to the site. The battery will begin commercial operation in June 2021.

The third project will deploy a battery on the system that is designed to allow islanding, mitigating potential outages on the circuit by continuing service to customers while an outage is restored, thereby providing an NWS that improves reliability and resilience. In 2020, two feasibility studies were completed to determine the viability of this project. Based on the results of these studies, the project is advancing to the next phase, involving design of the protection system required to island the customer. This system protection design phase will start in 2021, and a hardware-in-the-loop testing phase will be completed in 2022. Property acquisition for the battery site is scheduled to be completed in July 2021. The battery will begin commercial operation in 2024.

The fourth battery project will involve a small long-duration battery that will be used to support load transfers between distribution circuits with low capacity. The battery will be installed by the tie between two adjacent circuits and will allow both circuits to accept load transfers by providing additional capacity at the tie point between the circuits when transfers are needed. The addition of the battery will make the two circuits eligible for distribution automation. Enhancing distribution automation capabilities will bolster the Company's Grid Modernization and using a battery to do so provides another use case for an NWS to improve reliability. The battery will begin commercial operation in 2022.

Beyond the four battery projects described above, by 2025, the Company plans to use the Grid Storage sub-program to develop more battery projects that address the use cases identified, relying on the lessons learned in these initial projects to develop strong business cases. If technological breakthroughs in the industry create new compelling use cases, the Company may use this sub-program to test and deploy them.

While the Company plans to invest $10 million per year in this sub-program through at least 2025, investments could increase if circumstances warrant. The completion of the Company's 2021 IRP could lead to more batteries deployed earlier than currently planned. The Company could identify additional battery projects that are not currently under consideration, but which would provide clear benefits to customers, in which case the Company would include any proposals in a future electric rate case or other regulatory filing. Additionally, if the Company determines that it needs to deploy more batteries in the second half of the 2020's, perhaps to support grid stability as part of the solar build-out, then the Company could begin a ramp up of those deployments over the subsequent years.

Benefits

In addition to those benefits described above, the use of batteries to defer capital investments, as is the case with the planned portable battery, has great potential to reduce customer costs. Use of batteries will also provide insights regarding voltage control and the potential for energy market savings, both which will directly benefit customers. Each of these battery projects is also instrumental in further developing the Company's NWS capabilities.

xiii. Grid Modernization

Grid Modernization commonly refers to the planned process of investing in grid infrastructure improvements (poles, wires, relays, transformers, etc.) for the utility's electric grid; incorporating new technologies and applications into the electric system to increase reliability; optimizing the delivery system; and facilitating the integration of more diverse energy resources. While many utilities share common themes for defining Grid Modernization, different utilities can have different approaches for implementing and enabling Grid Modernization capabilities due to their unique customer, operational, regulatory, and business needs. This Grid Modernization sub-program invests in all of the devices and applications necessary for implementing the Company's Grid Modernization Roadmap, discussed earlier in this report, while continuing to invest in devices and applications that support automation of the system to improve reliability.

The Grid Modernization sub-program includes several investment categories and projects, as reflected in the Company's five-year investment plan below.

FIGURE 149

GRID MODERNIZATION CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
DSCADA	20.9	21.8	22.6	23.4	24.4
ATR Loops	21.3	22.1	23.0	23.9	26.5
Line Sensors	4.3	5.7	7.2	8.8	3.7

Regulator Controllers	9.9	11.4	6.9	-	-
LVD Capacitor Upgrades & Replacements	0.5	0.5	0.5	-	-
ADMS and Expansion	7.1	7.4	3.4	-	-
DERMS	1.2	1.2	7.1	4.8	4.9
Electric Grid Analytics	0.7	0.7	0.7	0.7	0.7
Reliability Predictive Analytics	1.3	1.2	1.2	-	-
Electric SIMS Conversion	-	0.5	0.8	-	-
Grid Modernization Incubator	2.5	8.4	1.4	1.0	0.9
Electric Grid Telecom Device Management	0.1	0.5	-	-	-
Electric Distribution Asset Management	1.0	2.0	5.9	3.1	3.1
Total	**71.2**	**83.4**	**80.6**	**65.7**	**64.2**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
DSCADA	125	100	122	122	122
ATR Loops	39	37	37	37	37
Line Sensors	1,700	2,193	2,800	3,400	0*
Regulator Controllers	430	430	320	-	-
LVD Capacitor Upgrades & Replacements	353	149	374	-	-

*Capital costs will still be incurred for software.

DSCADA

DSCADA is the key component of LVD substation automation, allowing the Company to open and close substation devices remotely without having to send a human operator. When DSCADA is installed at a substation, it includes a Remote Terminal Unit ("RTU"), a local device that facilitates communications with substation devices and remote software systems and captures over 300 data points within the substation using a cellular modem to transmit the data to the Company's operators. The enhanced visibility into substations and the remote-control capabilities together allow the Company to address outages more quickly and effectively. By enhancing visibility, DSCADA allows the Company's distribution planners to perform more accurate load flow studies because DSCADA provides access to real-time circuit data; load flow studies can therefore be dynamic based on time of year or day. The remote-control aspects of

DSCADA are crucial in enabling CVR, Fault Location, Isolation, and Service Restoration ("FLISR"), and Volt-VAR Optimization ("VVO") capabilities, and in making ATR loops operable.

FLISR allows the Company to quickly and automatically restore power to as many customers as possible, without requiring intervention by Company operators or crews. FLISR can detect a fault on the system and then automatically operate switches and reclosers to isolate the fault and transfer as many customers as possible to being served by an alternate substation or circuit until the fault can be addressed. This reduces outage durations for customers and reduces outage costs for the Company by reducing demands on service crews.

VVO enables coordinated control of voltage regulators and switched capacitor banks to reduce system losses and eliminate waste, using regulator controllers, capacitors, DSCADA, and ADMS. Without this capability, the Company must maintain voltage at the substation near the upper threshold of MPSC standards in order to ensure that voltage is delivered at a high enough level to customers once line losses are accounted for. By replacing regulators and capacitors, the Company can improve its voltage performance by reducing line losses. The major benefit of VVO is that it reduces line losses, enabling CVR, which provides a reduction in energy consumption. CVR is discussed in more detail in the Capacity Program section of my direct testimony.

Planning Process

When the Company began installing DSCADA, it developed a multi-year DSCADA deployment schedule based on three primary factors: (1) the need for DSCADA as a platform to achieve additional grid modernization benefits (e.g., ATRs and VVO); (2) to maximize AMI deployment benefits; and (3) to reflect the preference to deploy DSCADA by region instead of at dispersed substations across the state.

Benefits

The primary benefit of DSCADA is to enable other grid modernization efforts. DSCADA is a prerequisite for advanced ATR functionality, VVO, CVR, and several other advanced grid modernization capabilities. DSCADA also gives operators an early outage indicator for interruptions to an entire circuit, which allows for improved response and customer restoration time. DSCADA allows substation devices to be operated remotely, which often accelerates restoration, and always provides cost savings by avoiding the need to physically send field operators to the substation. DSCADA allows for monitoring substation health and preemptively removing equipment from service before it causes a permanent outage.

ATR Loops

ATRs are a key component for enabling distribution automation loops on the system. This technology is installed in sets on the system between two LVD feeders creating an automation loop, with three to five ATR devices being installed on a typical LVD circuit. ATRs transfer load automatically in the event of an outage, reducing customer outages and improving system reliability by isolating a faulted section of a circuit. ATR deployment is coordinated with DSCADA deployment, with the two classes of device being integrated by ADMS, all of which is critical in enabling FLISR.

Project Prioritization and Selection

When selecting ATR locations, the Company identifies all locations with existing infrastructure that can partially or fully support an automated transfer. The list of potential locations begins with a list of all three-phase ties between circuits, extracted from the Electric GIS. LVD planners then expand this potential site list with the locations of known historic load transfers. Circuits are ranked by SAIDI and LVD planners evaluate the list of potential ATR sites from the top down.

The Company generally targets the top 20% of potential ATR sites, sorted by composite SAIDI contribution of the two affected circuits. After evaluation by the LVD planners, a loop proposal is developed for each potential location, including a calculated cost/benefit ratio based on estimated unit costs for the required upgrades and projected performance, using three years of OMS archive data for the proposed ATR locations. All proposals are then ranked by their cost/benefit ratio to ensure the maximum reliability benefit for our customers.

Benefits

ATR benefits are easily measured using industry standard methods for distribution automation. When an ATR operates during a distribution event, the fault on the distribution system is automatically isolated and the rest of the customers are automatically restored within 90 seconds. In 2020, the Company had 49 successful ATR operations, which avoided 9.1 million customer outage minutes for a SAIDI reduction of 5.07 minutes. 33,172 customer outages were avoided altogether.

Line Sensors

Line sensors are devices that, by monitoring current, can detect faults and determine the faulted section and probable location of a fault, making them critical in enabling FLISR. Line sensors also provide information such as circuit loading, circuit balance fault current data, momentary outages, permanent faults, line disturbances, and high current alarms. In addition to operational capabilities, line sensors can be used to improve the entire LVD Planning process, by allowing more accurate load flow modeling.

Project Prioritization and Selection

The Company installs LVD line sensors on a circuit-wide basis, so the selection process is performed using a circuit-by-circuit analysis, using a combination of metrics from the Outage Management System ("OMS") Archive through the RAE. Circuit CAIDI, 10-year fault history (with faults in the last 24 months having higher weight), and number of overhead miles are all considered. Additional evaluation considers circuits with overloaded equipment (predicted via CYME and weighted by the percentage overload).

Once circuits for line sensors are selected, additional analysis is performed to choose the specific sensor installation locations. Sensor locations are strategically placed to break the circuit into zones of approximately one to two miles for optimized benefits of FLISR. Line sensors are often placed near non-communicating line reclosers to provide better protection coordination or placed near potentially overloaded equipment to verify loadings. Locations are also analyzed in CYME load flow models to ensure adequate amperage for inductive charging. The Company targets locations with 8 amps or more of current to maintain the sensor's full functionality. The location's conductor size, type, and length are also validated to ensure structural integrity.

Benefits

Line sensors monitor amperage, detect faults, and are used in determining a probable fault location, making them critical in enabling FLISR. Line sensors also provide information such as conductor temperature, phase balance, mis-phasing, load flow direction, fault current magnitude, and fault oscillography. Line sensors are used to improve the LVD planning process by providing more accurate load flow models and to provide early indication of potentially overloaded equipment. These enhanced load models can then be used to improve the load transfer process for both planned and unscheduled outages within ADMS. Fault oscillography provided by line sensors can also be used to verify proper coordination between protective devices on the LVD System.

Regulator Controllers

Voltage regulators are tap changing transformers utilized to increase or decrease voltage on the primary distribution system based on changing load conditions. Controllers allow remote control of the regulators. Voltage regulators contain internal windings and mechanisms to adjust the voltage by up to 10% in either direction, are located on the pole top, and are connected to regulator controllers at the pole base. The Company is in the process of replacing the existing control devices with modernized voltage regulator controllers that will enable two-way communication between the controller at the pole base with the LVD SCADA system, a process that the Company expects to complete by the end of 2023.

Project Prioritization and Selection

Because the CVR program requires DSCADA information as a data source, line regulators on circuits with DSCADA are prioritized in the regulator control upgrade program. The deployment of line regulators on DSCADA-enabled substations is planned by geographic region to allow for efficient crew travel and resource utilization.

The Company also prioritizes regulator control upgrades based on customer service voltage and locations requiring pole top replacements.

Benefits

With remote monitoring and control, the Company can ensure that it is providing customers with the correct voltage and can improve system efficiency. Modernized regulators and controllers are critical in enabling VVO and CVR. Voltage control is further enhanced by remote controlled capacitors, which provide reactive power to the distribution system, correcting power factors by compensating for reactive losses and thereby increasing voltage. These capacitors are also controlled by cellular modems at the pole base.

LVD Capacitor Upgrades and Replacements

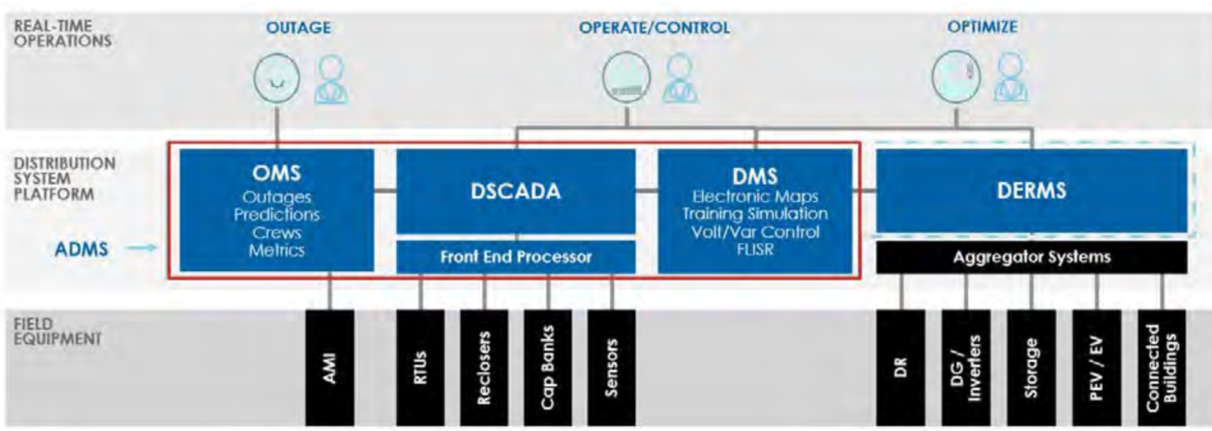
In 2018, the Company completed the deployment of nearly 3,800 upgraded capacitor controllers throughout the LVD system. The LVD capacitor upgrade and replacement investment category consists of installing neutral current sensors at these locations to leverage the remote capability provided by the capacitor controller, which the Company expects to complete by the end of 2023. These neutral current sensors are installed at the pole top capacitor assembly and connect to the bottom of the controller at the pole base. The sensors provide neutral current readings, which is a critical indicator of phase imbalance that indicates a likely blown fuse. This data enables quick identification of capacitor locations that require maintenance to improve system efficiency. This investment category also includes the replacement of failed capacitor equipment such as oil switches, capacitor tanks, and cut-outs.

ADMS and ADMS Expansion

ADMS is a software platform that integrates components of Grid Modernization, incorporating data from the different devices of the distribution system to increase automation and improve real-time outage management. It is critical to enabling all the Grid Modernization capabilities, including DER integration, laying the foundation for DERMS. ADMS combines a new Distribution Management System ("DMS") and OMS into a single platform, replacing the Company's existing OMS, and integrating these components with DSCADA, as illustrated in Figure 150 below. ADMS also integrates the Company's GIS mapping to provide operators and dispatchers with an accurate view of the distribution system, phasing out the need for traditional paper-based single line system diagrams and maps. The Company began its deployment of ADMS in 2019 and will compete initial deployment in 2021.

Figure 150

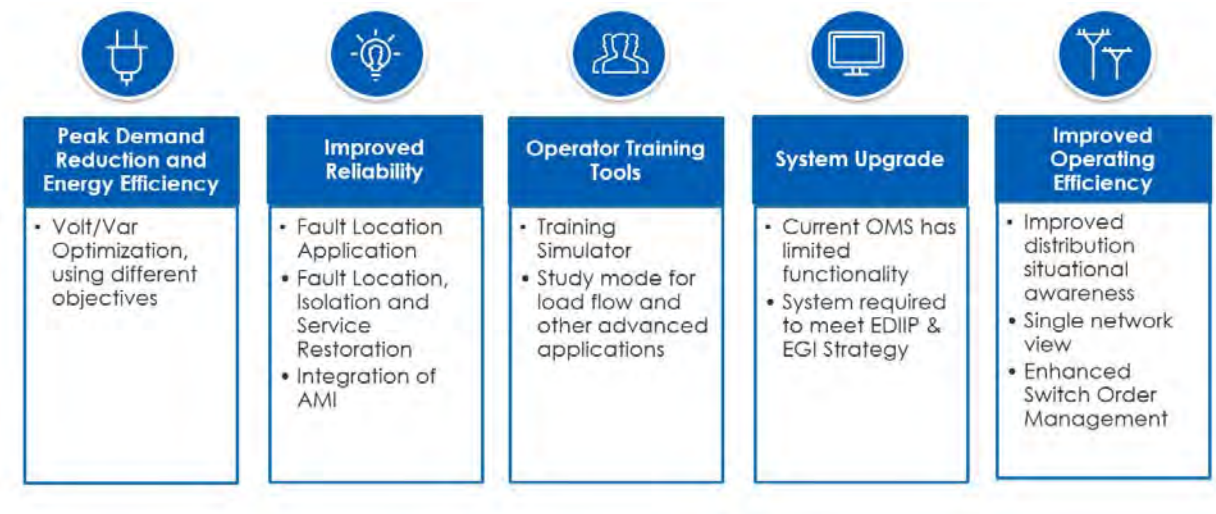
ILLUSTRATION OF ADMS



ADMS will enable the Company to perform load transfer studies more quickly. Prior to ADMS, it took about four hours to complete such a study manually; ADMS reduces this to less than 30 minutes, delivering benefits to customers by reducing outage times through load transfers. The Company has calculated that this will reduce SAIDI by up to 10 minutes with $226 million in net benefits to customers. Additional benefits of ADMS are shown in Figure 151 below.

FIGURE 151

SUMMARY OF ADMS BENEFITS



As the Company finishes its initial ADMS deployment, it will transition into an ADMS expansion in 2022 and 2023. ADMS expansion consists of three enhancements and the initiation of an upgrade to the Company's ADMS platform.

The first enhancement includes the deployment of a field mobility application that will extend the use of ADMS functionality to the Company's field workforce, providing up-to-date maps and records of energized facilities. This mobile application will also allow storm and field resources to update, in real-time, the current state of the electric system during outage events. This will help ensure field workers are aware of potential safety hazards in the vicinity of all worksites and allow for the collection of accurate damage assessment information that will be reflected in the ADMS platform.

The second enhancement includes updates to SOM capabilities. This addition will allow operators to enhance electronic switching orders to comply with applicable safety policies and standard work practices not included in the standard SOM list of available action steps.

The third enhancement will integrate ADMS with additional electric geospatial information modeling and attributes to support additional devices, including smart inverters connected to DERs and underground electric infrastructure. This will enable additional monitoring and control capabilities on more areas of the electric system.

The ADMS platform requires system upgrades to ensure the system has the latest version of software around every three years. The next ADMS platform upgrade, referred to as Monarch 2020, will begin in 2022.

DERMS

DERMS is an advanced software platform including, but not limited to, specific functions to forecast, monitor, control, and coordinate DERs on the electric grid. The DERMS application will provide several key functions including aggregation, translation, simplification, and optimization across a wide variety of

DERs. DERMS will optimize DER performance at multiple levels based on multiple requirements including local, regional, and system-wide applications.

The Company is beginning deployment of DERMS in 2021 in a phased-in manner, allowing the Company to initially learn by monitoring and controlling DERs on a small subset of circuits and substations to understand the unique challenges associated with managing DERs. As DERMS matures, the Company will follow this initial small-scale DERMS deployment with an Enterprise DERMS solution integrated with ADMS. The Company plans to move to broader deployment in 2023.

The Company is confident that DER penetration will accelerate in the relatively near future, with continued commitments to distributed solar generation, as well as the potential for customer-sited storage, which the Company plans to pilot as discussed in the NWS section. This accelerating DER penetration will introduce various technical questions, primarily related to control and optimization of DERs, that must be addressed. Consistent with the Company's current DERMS deployment schedule, the Company will develop its DERMS capabilities by the end of 2023.

If the Company were to delay its DERMS deployment schedule, it would create an increased risk that DER penetration gets too high to reliably manage and control before the Company's DERMS is ready. This would yield unacceptable reliability risks, as uncontrolled DERs may result in voltage, frequency, and power production that is detrimental to the electric grid. When DERs are on the system in appreciable quantities, operational challenges may begin to threaten reliability.

Studies by the PJM Interconnection, the North American Electric Reliability Corporation, and the Electric Power Research Institute ("EPRI") have shown that operational challenges begin to manifest themselves when DER penetration reaches between 20% and 30% of the regional electric demand. Currently, DERMS is necessary to reliably manage DERs at peak conditions, and to generally coordinate DERs so as not to introduce voltage issues or other issues that threaten reliability. In short, while DERMS is not addressing a specific reliability threat that exists in 2021, it will prevent a reliability threat that is likely to exist by the time the project is complete if no action is taken.

<u>Benefits</u>

Developing DERMS now in anticipation of future DERs prepares the Company to quickly and efficiently connect DERs in the future, which will enable both Company and customer ambitions of deploying various energy technologies in the future.

Distribution Reliability Predictive Analytics

The Company is contracting with a third party to develop an application to improve the Company's ability to leverage its Geographic Information System ("GIS") data. Prior to this investment, when Company employees are in the field to do system assessments, to evaluate site conditions for work, and to conduct preliminary design work, they capture images using various devices. Those images then reside on individual employee computers, unavailable to other employees in a seamless way, and eventually much of the imaged information is lost. The purpose of this project is to create a way to seamlessly integrate these images of system assets into the Company's GIS data. When the image is associated with an asset, the Company can determine potential impact to customers, and will be better positioned to address the highest-risk issues as soon as possible. This project will also help the Company increase system assessment frequency. Currently, the Company assesses its LVD system once every six years, but as infrastructure ages, the Company will need to increase this frequency. This program, after it is complete in 2023, will streamline that process and ensure that GIS data is periodically validated.

Benefits

This project will help ensure that crews have the right equipment and material to perform their work before they arrive in the field. There are several examples of information that, when stored with an image in the Company's GIS data, can improve the efficiency of repairs and other field work. It could indicate a high traffic area where traffic control would be required to complete a job. It could indicate muddy terrain, requiring specialized vehicles to complete a job. It could indicate that a pole is in a customer backyard where there is an aggressive dog, meaning precautions need to be taken.

Additionally, images that are centrally stored and associated with assets through GIS data can be provided to designers, who can then determine what, if any, engineering is needed for a project without making a field visit. Schedulers will be better able to group issues that are close to one another, minimizing crew travel time. The Company will be better able to evaluate defect trends and optimize assessment frequency. Images captured before and after a job can be compared to validate the work.

Electric SIMS Conversion

The Company has a data record set that shows underground services in an outdated computer-aided design (CAD) format. The application that contains this data has become unsupported and obsolete. The conversion of these records, which will take place in 2022 and 2023, to the Company's Electric GIS system will both provide accurate location data on underground electric services for public staking and improve safety for the Company's electric operations employees.

Grid Modernization Incubator

The Company has historically tested new technologies with pilots in the field to determine viability for system-wide deployments. Piloting new technology in the field has drawbacks including potential reliability impacts; limited ability to complete all beneficial testing, including interoperability and operational readiness; and inability to fully train crews prior to the use on the system. While this has resulted in mixed success in the past, this solution will not work for more complicated technologies that the Company will be deploying in the coming years. For example, the Company has had safety concerns associated with ATR installations due to crews not being familiar with the new technology, resulting in higher costs and reliability impacts.

It is difficult to test new technology and cyber security improvements on production Information Technology ("IT") infrastructure. It is also difficult to test and develop new standards on existing standard installations. For example, development and testing of interoperability, cyber security, and new communications architecture should be tested on a non-production network and facility to gain the knowledge needed as the Company develops DER integration and coordination strategies. As technology, DER coordination, and protocols mature, the Company needs an ongoing strategy for enabling these improvements.

As the Company shifts from centralized control systems to a more distributed architecture, it will need to test and prove the suitability of these control systems before deployment in the field. Grid-edge computing will allow for local operational decisions to be made dynamically and without operator intervention for events affecting supply and demand like cloud cover and load shifting. The same concept applies to system protection schemes needed to support the developing operational needs related to distributed generation. Not only do new controls and protection schemes need to be developed and tested, but the Company also needs to develop standards, develop procedures, and train personnel on the new technology before field deployment. For example, it is important that control and system protection designs be validated for new automation schemes like FLISR and anti-islanding.

The most effective way to resolve these issues is to build a testing and training facility with flexibility for both present and anticipated technology to meet the testing requirements for technology across the electric distribution organization. It will allow for testing, troubleshooting, training, and the creation of standards and procedures for installation and operation prior to field construction. It will be energized and operated on an isolated, private network and will not offer support to the grid. In order to run tests and to perform operations, the facility will include solar generation, battery storage, natural gas generation, and load banks. The facility will also include a real-time data simulator to test real-world problems with hardware in the loop and digital twin capabilities. This will allow testing and training with no impact to customers. The facility will have the capability to test in utility-scale and customer-sited devices, allowing for testing of software and hardware solutions related to multiple company initiatives.

The testing and training facility will be considered a technology incubator to demonstrate how this facility can support and encourage effective innovation that will be necessary for Consumers Energy to manage the dynamic electric grid of the future in support of the Company's Clean Energy Plan. Building and site requirements across many stakeholder groups will be developed in 2021. Design will begin in 2021 and continue into 2022. Construction will begin once design is completed in 2022.

Electric Grid Telecom Device Management

This project, to be completed in 2021 and 2022, will implement a solution for managing the telecommunications device component of Grid Modernization that includes managing device metadata and the ability to historically manage the real-time status of telecommunications devices.

The implementation of a communications management system that can monitor and maintain multiple wide-area network/field-area network device types also adds value by consolidating data from multiple disparate systems into a central repository which can then be used to manage and analyze the disposition and features of distribution grid telecommunications devices. Additionally, a platform that enables both GIS integration of asset location and telecommunication asset inventory for future substation communication needs will enable geo-based trouble analysis and proactive replacement of similar types of faulty communication equipment.

<u>Benefits</u>

Completion of this project will benefit the Company by: (i) reducing hours spent combining data from several platforms; (ii) providing visibility into devices on the electric distribution system, including a consolidated view of multiple device types; (iii) providing highly reliable communications to field control devices in support of advanced grid functionality; and (iv) improving the ability to troubleshoot and perform root cause analysis, leading to improved reliability and a reduction in dispatching field crews for troubleshooting devices.

Electric Distribution Asset Management

This project will develop a Distribution Asset Management strategy, with corresponding process and technology implementation plans and objectives. The Company will gain value from this project through: (i) creating a standardized process for designers and field resources to collect and manage asset data, reducing waste and rework associated with current processes; (ii) optimizing planning and management of distribution assets, resulting in investments of highest value; (iii) establishing a channel for the Company to develop and manage asset health conditions on the distribution system, optimizing the O&M investments of distribution assets; and (iv) improving the quality of Company electric distribution asset data, optimizing asset performance and providing opportunities to leverage quality data to support other engineering and operations efforts.

Electric Grid Analytics

In the 2018 EDIIP, the Company introduced a phased approach for enabling new analytics, with ongoing incremental improvements in which work is done in short “sprints.” (In the 2018 EDIIP, this was referred to as “Grid Operational Analytics.”)

In 2020, the Company created voltage, misphasing, and interruption analytics using smart meter data, although context was usually limited to individual meters, meters served from a common secondary transformer, or all meters grouped *en masse* to their common feeder.

In 2021, the Company is continuing investing in additional analytics capabilities using electric network connectivity data and DSCADA data to be able to evaluate misphasing without having to wait for an outage event, moving the analytic from being a reactive analysis to a proactive analysis. This will enable the Company to run the analytics on a system-wide basis, not just for those locations that have experienced an interruption of service. This investment will also enable completion of more advanced analytics for loading, power quality, and outage analytics.

In 2022, meter reading data such as kWh consumption and voltage reading types, along with meter event types such as power out/restored indications and high voltage alarms, will be integrated with network connectivity data that describes the LVD system. This will enable new electric grid analytics that considers which meters are upstream and downstream from each other. It will also show where they are relative to primary devices such as line fuses and voltage regulators. As the Company expands DSCADA deployment within the LVD system, when comparing smart meter data to DSCADA data, the Company will be able to identify which meters are upstream or downstream from each line device. For example, if an analysis of voltage data from smart meters shows an issue that is more widespread than a single, defective secondary transformer, knowing which meters are upstream and downstream from a voltage regulator may show that the device is not operating as intended and it can be slated for inspection and maintenance.

Additional “sprints” will be identified for 2023 through 2025 as those years get closer, based on needs to be identified.

F. Capacity Program

The Capacity Program is designed to: (i) ensure that the HVD system is capable of serving forecasted electric peak demand when all HVD facilities are in-service; (ii) ensure that individual HVD facilities can be taken out of service during non-peak demand periods without loading equipment beyond ratings of providing unacceptably low voltage; and (iii) fix LVD equipment loads after they occur. In general, projects in this program consist of either upgrading the size of assets so they can accommodate more load or installing new assets to relieve load on existing assets.

Additionally, the Capacity Program includes new sub-programs designed to implement elements of the Company's IRP: the CVR sub-program includes work to put that component of the Company's IRP into effect, while the Interconnections sub-programs will allow the Company to add new solar generation to the grid.

Each Capacity sub-program consists primarily of investments that are discretionary, in that they do not respond to an emergency, meaning the Company has some ability to prioritize and reprioritize its projects in these sub-programs. Because of this, the Company may, during a given year, pull forward projects that originally would not have been anticipated until later if conditions warrant. For example, if unexpected load growth caused an LVD asset to be overloaded earlier than anticipated, the Company could pull forward a Capacity project to address that asset.

Overall, on an annual basis, the Company's planners assess the entire electric system to ensure that it can reliably serve customers under the most stressful conditions, particularly under peak load conditions when all customers are collectively using the most energy. This assessment involves comparing the capacity of each element of the electric system to the maximum projected (peak hour) loading of the customers being served by that element. For those elements where loading is projected to exceed its capacity, the Company's planners will examine remedial actions, including replacement of the element. Any new element is sized with a capacity that is greater than the maximum projected loading. Therefore, peak demand dictates the capacity of elements, which is one of the key determinants in the investment in distribution because capacity is directly related to cost (i.e., higher capacity equates to higher cost).

Each year, after summer peak conditions, the Company revises its load forecast to reflect the most recent experience with customer peak usage. The load forecast is done at the system level and represents the simultaneous usage of all customers. Using these peak load projections, the Company uses sophisticated power flow modeling to identify loading on each element. The power flow model simulates how power flows on the electric system based on the fundamental laws of electricity. These models can identify loading on each element, compare it with the capacity of that element, and provide the Company's Planning Engineers with those instances where capacity is insufficient to meet projected loading.

The Company's design engineers determine capacity of elements based on manufacturer or industry resource standards (i.e., IEEE). Multiple data sets and software programs are used to assist in determining capacity of each element. Capacity is determined based on allowable loss-of-life of each element, which varies by element.

In its December 17, 2020 Order in Case No. U-20697, the Commission directed that AMI data should be used in the Company's load forecasts, which would have particular bearing on the Capacity Program. However, it is important to note that many Capacity Program projects are not being driven by forecasted load growth, but instead respond to assets that are already overloaded beyond their rated criteria, resulting in already-ongoing voltage issues for customers. Many other Capacity Program projects are driven by known customer-specific load increases; in these cases, customers have communicated their anticipated load increases to the Company.

As discussed in relevant sections below on specific Capacity sub-programs, the Company uses CYME to analyze loading on the distribution system. The Company obtains data from its DSCADA system and from meter reads of maximum substation loads. The Company also obtains data from AMI meters at each customer. This load data is analyzed by CYME in order to apportion the maximum substation load to each customer. This is a “top-down” approach where maximum, aggregated substation loading is modeled down to the customer level.

CYME is capable of a “bottom-up” approach, too, where it can aggregate customer data from AMI to determine maximum substation loading, but this is a time and labor-intensive process. The Company has observed to date that the top-down modeling process – using DSCADA and substation meter data and using CYME to allocate it to known customer locations – produces meaningfully identical results to a bottom-up process that would aggregate AMI data. Because there are, at present, few DERs on the system, bottom-up AMI-based modeling does not provide any forecasting advantages. Again, most Capacity Program projects are not based on forecasts in any case but are based on overloads that have already taken place or are anticipated to take place based on known specific customer load increases.

As DER penetration increases in the future, the Company recognizes the logic in using more AMI data to inform load forecasts, although this is not generally relevant to the specific Capacity projects that the Company has developed for 2021 and 2022. In preparation for DER penetration, the Company is participating in an EPRI effort to develop advanced distribution planning software that will employ a bottom-up approach using AMI data, will simulate hourly power flow for up to a 10-year period, and will have built in models for various NWS.

i. LVD Lines Capacity

Capital investments in the LVD Lines Capacity sub-program prevent line and equipment overloads due to increased demand on the LVD system, resulting from customer load growth, increased consumption, or load shifting from one area to another. These investments fund critical projects to address capacity loading issues in accordance with planning criteria, and to address new load additions, to ensure that the LVD system can meet projected distribution loads.

Investments in this sub-program are divided into two categories: (i) equipment upgrades, and (ii) lines capacity projects associated with substation projects. Investments in substation line work have a higher priority than upgrades to overloaded LVD equipment, due to the need to provide minimum load and voltage service to the most customers. Historically, this sub-program also included work to upgrade equipment based on new business growth, but that work is included in this filing in a separate sub-program, LVD New Business Capacity.

Over the next five years, the Company plans to invest between $11 million and $13 million per year, in this sub-program, as shown below:

FIGURE 152

LVD LINES CAPACITY CAPITAL INVESTMENTS

5-Year Capital Plan (all values in $ millions)					
Investment Categories	2021	2022	2023	2024	2025
Upgrade of Overloaded Equipment	7.5	8.3	7.9	8.0	8.1
Line Work Associated with Substation Capacity Projects	3.8	4.9	4.6	4.7	4.7
Total	**11.3**	**13.2**	**12.5**	**12.7**	**12.9**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Upgrade of Overloaded Equipment (# of Upgrades)	34	54	27	27	27
Line Work Associated with Substation Capacity Projects (# of Projects)	7	5	5	5	5

Upgrades of Overloaded Equipment

The Company upgrades or replaces overloaded lines and equipment, or rebalances the system, to reduce reliability and safety risks, including equipment failure; nuisance disruptions of sectionalizing devices (e.g., fuse links melting); potential oil spills; equipment heating with a potential risk of fire; and conductor sagging or failure, creating a public safety hazard of potential contact. While this investment category does not drive incremental SAIDI improvement, it prevents future failures that would result in an increased SAIDI.

Line Work Associated with Substation Capacity Projects

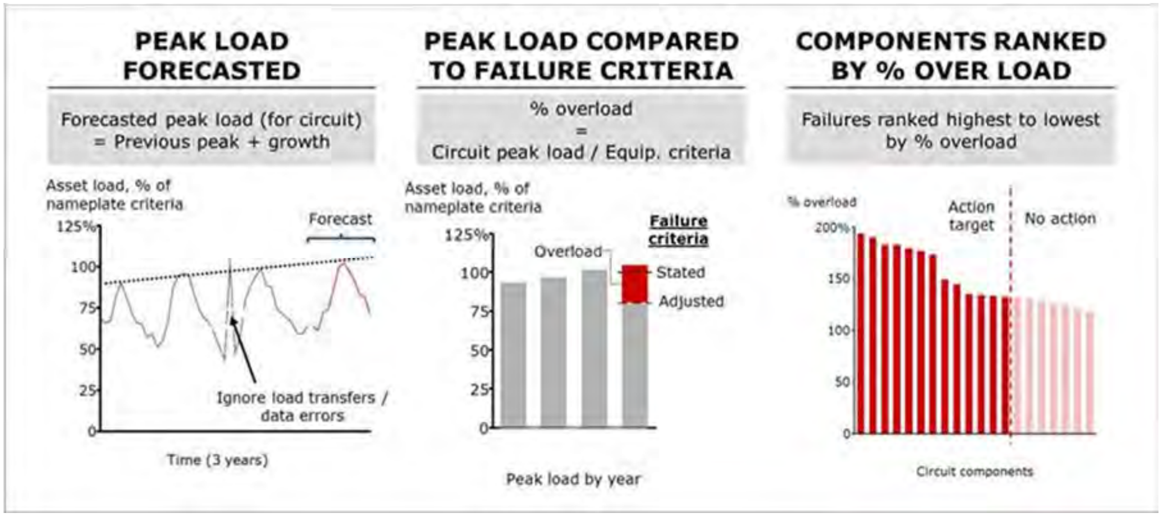
Since substations are part of the backbone infrastructure of the electric distribution network, LVD Lines Capacity projects must be completed to reduce the risk of failure due to substation equipment overload.

Planning Process

The Company's project selection follows three steps: (i) considering peak loads; (ii) comparing peak loads to failure criteria; and (iii) ranking components by their percentage of overload. See Figure 153 below for an illustration of this process.

FIGURE 153

LVD LINES CAPACITY LOAD REVIEW PROCESS



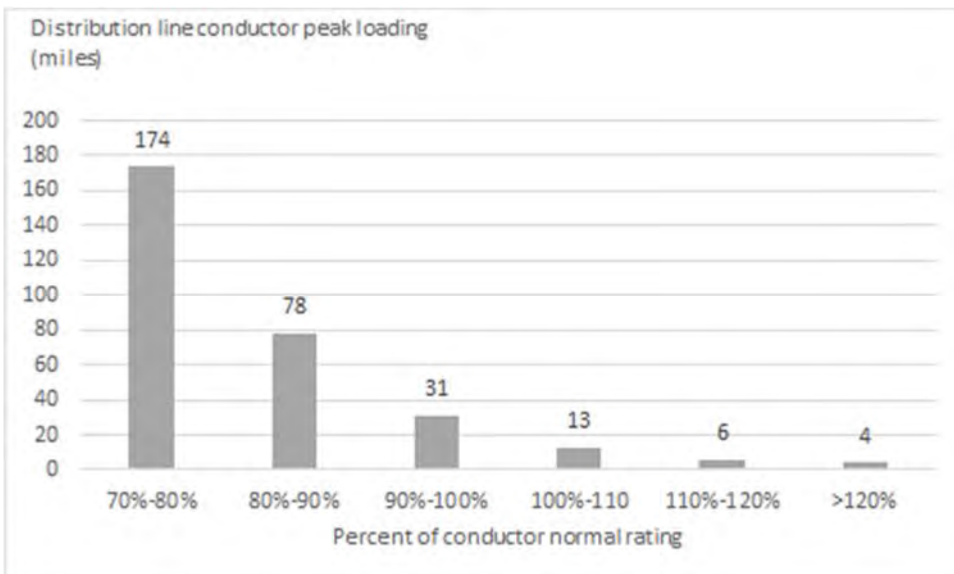
All planning activities in this sub-program are based on projected peak load conditions, which is when capacity is most challenged. The Company uses normal, or continuous, ratings for peak load conditions, due to the heightened risk of equipment failure or degradation when operating above the capability rating. The loadings on equipment are established by the manufacturer, or by a recognized industry source such as IEEE, and specify the optimal operation of the equipment based on the capability characteristics of the components. The specific evaluation of each piece of equipment depends on its use. For example, equipment using oil is rated based on a temperature limit not to be exceeded. If that operating temperature is exceeded, then the equipment can start to break down and possibly lead to a shorter lifespan. Other equipment has a defined set of characteristics that, when taken beyond the manufacturer specifications, can lead to a change in characteristics of the material, altering its strength and durability.

The Company evaluates the LVD system using CYME, an industry-standard power flow software, to perform a power flow analysis. CYME uses load information from two databases to perform power flow studies, the Feeder Demand database and the Customer Loads database. The Feeder Demand database provides the maximum amperage experienced on the circuit with data from substation metering equipment. The Customer Loads database uses customer meter data. The CYME power analysis compares the Feeder Demand load at the substation to the Customer Load distributed across the circuit to determine power flow, voltages, and system protection needs. This analysis is performed on current and future states of the system. This process identifies overloaded distribution equipment and instances of unacceptably low or high voltage during system peak load conditions.

The Company evaluates loading on its LVD distribution equipment, utilizing CYME, on an annual basis, for capacity planning purposes. Additionally, studies are completed throughout the year to address emergent issues such as load transfers, generator interconnections, and reliability failures. Capacity planning criteria requires that a component of the distribution system have a projected load over its peak capability based on our standards for equipment overload capability before a capacity project is required. Previous year loadings and future customer growth are considered when projecting future loadings. While most equipment has emergency ratings that enable higher capacity for short durations, these are not considered during capacity planning, because loading at these higher levels results in degradation and eventual failure.

Figure 154 shows conductor overloads on the system based on peak loading. Note that the total miles captured in this chart represents a small percentage of the total LVD line miles on the system.

FIGURE 154
LVD LINE CONDUCTOR PEAK LOADING



When a capacity issue is identified, the Company identifies several alternatives for addressing the overload. These alternatives include:

- **Upgrading equipment** – The present equipment is replaced with items of a larger nameplate rating, matched to the increased loads, to handle increased ampacity. For example, the Company may increase the size of a fuse, isolator, regulator, capacitor bank, or substation recloser to accommodate ampacity. Ampacity measures the maximum amount of electric current a conductor or device can carry before sustaining damage or deterioration;
- **Conductor upgrades** – Conductor upgrades can be used in place of increasing the size of equipment, or to handle the increased ampacity on the conductor. For example, the circuit

planner may choose to replace the conductor instead of an overloaded regulator to increase voltage stability and reduce line losses;

- **Voltage conversion** – The circuit planner may decide to convert the voltage to a standard voltage (refer to the LVD Lines Reliability capital sub-program) rather than replacing an overloaded isolator; and
- **Load balancing or transfer** – When equipment or conductors are overloaded, the Company may be able to decrease load on that equipment by balancing the load with other phases on the same circuit or transferring load to an adjacent circuit. This may require a phase change for the customer or adding an additional phase to offset the overloaded zone. Distribution line systems carry between one and three phases on each circuit.

Project Prioritization and Selection

The Company prioritizes capacity projects based primarily on overload level, addressing the highest overloads prior to lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact. Circuit planners identify overloaded equipment and develop project proposals based on the overload percentage, equipment type, number of customers affected, estimated project cost, and any related customer complaints. The goal in capacity planning is to develop a project proposal for all equipment where loading exceeds manufacturer recommended levels.

LVD Lines Capacity projects are prioritized by the program planner by evaluating costs and benefits, based on their experience and knowledge of the system, and the availability and location of resources. Projects that provide the greatest benefit to the grid are sequenced for the work plan and added to the construction plan.

The planning process occurs in the current year for construction two years out. This allows time to prepare a design, order materials, acquire any necessary easements, devise a plan to address forestry concerns, and potentially install line sensors to monitor the loads to see if the investment can be deferred (or even pull it ahead if the loads are higher than anticipated). In order to maximize customer benefit, it is a prudent business practice to utilize the best, most timely data available.

An example of an LVD Lines Capacity concept approval is shown in Appendix D

Benefits

In addition to the expected SAIDI benefit, the Forestry benefit associated with this capital work increases the overall benefit, as capacity projects generally include some line clearing work that benefits the larger system. The investments made to upgrade overloaded assets and alleviate voltage issues increase the longevity of the equipment on our system and prevents service issues/interruptions to our customers while improving employee and public safety.

ii. HVD Lines and Substations Capacity

This sub-program consists of HVD enhancements in accordance with HVD planning criteria; work to accommodate new interconnections; and work to improve functionality through standards, upgrades to protection, operability of the system, and coordination with transmission infrastructure additions. It also supports ROW acquisition projects to support HVD Lines, HVD Substations, and LVD Substations capacity and reliability projects.

HVD Lines and Substation criteria specify that the HVD system must be capable of: (1) serving forecasted electric peak demand with all HVD facilities in service; and (2) withstanding single elements (equipment or lines) of the HVD system being out of service during non-peak demand periods due to failure or for maintenance and construction, without loading remaining HVD facilities beyond equipment ratings or reducing voltage to unacceptably low levels. The criteria also specify that interrupting devices must be capable of interrupting the available short circuit current. Interrupting devices are scheduled for replacement with higher capability units when the available short circuit is projected to exceed the equipment interrupting capability.

Since the HVD system is the backbone infrastructure of the electric distribution system, capacity projects must be completed on an as-needed basis to serve customers and maintain overall reliability. These projects tend to require long lead times, typically one and a half to two years, due to the need to acquire large equipment such as transformers, and ROW procurements. For this reason, projects are planned based on forecasted load growth (using the 65% confidence level of the corporate forecast of future system peak loads) to ensure the project can be constructed in time to meet the system need.

The Company's five-year investment plan in this sub-program is as follows:

FIGURE 155

HVD LINES AND SUBSTATIONS CAPACITY CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
Investment Categories	2021	2022	2023	2024	2025
Load Carrying Capabilities and Voltage Support	7.8	2.6	5.0	5.0	5.0
New Interconnections	2.2	4.8	2.5	2.5	2.5
Improved Functionality	5.4	6.6	6.6	6.6	6.6
Coordination with Transmission	3.2	4.8	2.5	2.5	2.5
ROW Procurement	1.7	1.4	3.5	3.5	3.5
Potential Large Projects	-	-	4.5	8.3	3.9
Total	**20.3**	**20.1**	**24.6**	**28.4**	**24.0**
Unit Forecast					
Investment Categories	2021	2022	2023	2024	2025
Load Carrying Capabilities and Voltage Support (# of Projects)	5	1	8	8	8
New Interconnections	12	13	14	14	14
Improved Functionality (# of Projects)	9	13	19	19	19
Coordination with Transmission (# of Projects)	9	6	6	6	6
ROW Procurement (# of Projects)	10	2	15	15	15
Potential Large Projects (# of Projects)	-	-	1	2	1

Load Carrying Capabilities and Voltage Support

The Load Carrying Capabilities and Voltage Support category contains projects that eliminate unacceptably low voltage, and loadings above line and equipment ratings. The Company studies the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in power flow and voltages resulting from single outages for present and future versions of the HVD system. Through this process, HVD facilities are identified that would violate criteria due to line or equipment overload, or due to unacceptably low voltage during base (normal) conditions at system peak load or during single (N-1 equipment out of service) outage conditions at 80% of system peak load. Outage conditions studied include single line, single transformer, single bus, and single generator outages. Projects are developed to eliminate unacceptably low voltage, and loadings above line and equipment ratings.

The Company updates its models annually to model peaks one, three, and six years forward, with 80% HVD loading. Modeling data are stored in a Microsoft Access database and then imported into PSS/E, a commercially available AC power flow modeling program from Siemens Power Technologies, Inc. The models include a detailed representation of the HVD network. Distribution and dedicated customer substations are individually modeled with the loads aggregated on the low-side bus of the substation transformers. Modeled loads are reviewed and updated on an annual basis using various sources such as SCADA, MaxLoad, and MV90.

The Company's plans to fix projected criteria violations are tested in the models to ensure they fulfill their designed purpose. SCADA information is also used to project future load on the HVD system. The short circuit model of the HVD network compares the available short circuit current to the interrupting capability of the HVD interrupting equipment. These capacity projects must be completed on an as needed basis, based on projected loading in power flow models. The HVD system model is updated annually, following summer peak loading and into the first quarter of the following year. The studies are performed in the second quarter each year, and projects are then developed to address identified projected issues before the issue occurs in subsequent years.

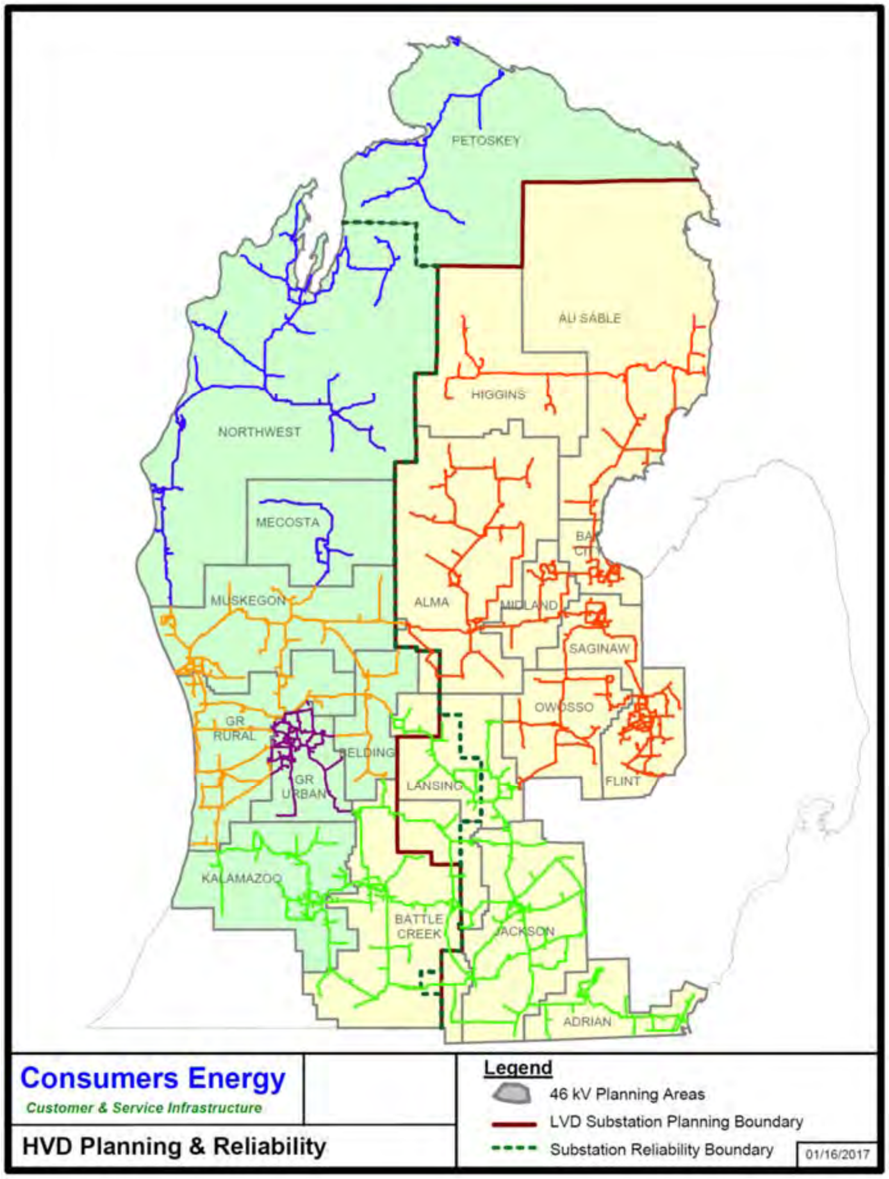
Distribution buses are grouped into 20 geographic planning areas, as shown in Figure 156, with one additional area comprised of 138 kV-connected, dedicated industrial-customer substations. Load projections are developed for each planning area based on the area's individual historic growth rate. Individual bus loads within each planning area are also reviewed to capture load shifts that occurred since the last series of planning models. The individual projected area loads are then normalized so that the total system load, plus losses on the Company's system and METC's system, matches the corporate peak MW demand forecast at the 65% confidence interval for the peak case. For each peak load model developed, a corresponding model at 80% of peak load is derived from the peak case.

The HVD system interconnects to the transmission system and, accordingly, HVD planning models are integrated into a model of the transmission network using a peer-reviewed transmission model from the NERC Multiregional Model Working Group ("MMWG"). This MMWG model represents the entire Eastern Interconnection, including full details of nearby transmission systems such as METC/ITC, AEP, First Energy, IESO (Ontario), ATC, and NIPSCO.

Generation dispatch for the models are based on the integrated Consumers Energy HVD/NERC MMWG model. For the peak models, Company base load and peaking units are dispatched so that the net MW interchange matched the scheduled transactions. For the 80%-of-peak-load models, the peaking units are turned off and the base load units owned by the Company and by DTE Energy, as well as independent power producer units in Michigan, were adjusted based on an economic dispatch in proportion to the reduced system load.

FIGURE 156

GEOGRAPHIC HVD PLANNING AREAS



Proposed plans are tested in the models to ensure they fulfill their designed purpose. SCADA information is used to project future load on radial lines. The short circuit model of the HVD network compares the available short circuit current to the interrupting capability of the HVD interrupting equipment. These capacity projects must be completed on an as-needed basis, based on projected loading in power flow models.

An example of a concept approval in this area is provided in Appendix D.

New Interconnections

The New Interconnection category contains new interconnections to LVD substations, other utilities, and generation facilities that must be completed as requested by the interconnecting party. Costs to interconnect other utilities and generation facilities to the Company's HVD system are reimbursed by the other utilities or generators being interconnected.

Improved Functionality

The Improved Functionality category contains projects that are completed to meet changes in standards and upgrades to protective schemes on a planned basis over a period of time. An example of this is the Company alleviating substation NESC working space issues systematically over a 10-year period. It is often coordinated with other major projects as they occur at the same location. Configuration changes to improve operability are made at the request of the Grid Management group, or through coordination with other major projects as they occur at the same location.

Coordination with Transmission

The Coordination with Transmission projects, such as HVD relay upgrades associated with transmission upgrades, must be coordinated with those transmission upgrade projects that require the HVD upgrades to be completed. These are completed as needed over time in conjunction with the transmission owner.

ROW Procurement

The ROW Procurement projects are necessary to procure HVD line rights or substation sites. These projects are critical to prepare for HVD construction and can require significant lead time. Acquiring the necessary land, or land rights, is key and integral to advancing HVD lines and substation projects across multiple capital sub-programs. These projects must be prioritized to adequately support the project that is depending on the new rights (e.g., new HVD line, HVD line relocation or rebuild off-center, new HVD or LVD substation, or improved easements where rights are determined to be inadequate). As an example, through the process of monitoring and studying load profiles, properties are sought and procured in order to build electric infrastructure at the right point in time needed to serve customers.

Improved functionality, coordination with transmission, and ROW procurement projects are scheduled as they develop in conjunction with the associated project being supported.

Benefits

Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid. Investments in this sub-program improve system reliability by preventing future overloads. Furthermore, these investments help avoid dangerous wire downs and equipment failures due to overloads and exceedance of equipment interrupting capability, improving system safety.

iii. LVD Substations Capacity

The LVD Substations Capacity sub-program ensures the long-term safe and reliable operation of our electric distribution LVD substations. The necessary capital expenditures include investments to install new substations or substation equipment and to upgrade existing substations or substation equipment to ensure customer electric loads are served within the operating capacity of the installed substation equipment (i.e., transformers, fuses, reclosers, regulators, and switches).

LVD Substations Capacity planning activities are based on peak load conditions. Monitoring and analysis are done to identify situations where a component of the LVD substation has experienced an overload of its rated capacity. LVD substation capacity projects are prioritized to address the highest overloads in advance of lower overloads, with adjustments made for other factors such as historical reliability, customer mix, and safety impact. When assessing loads, the Company prudently considers actual and known new business load additions.

When the Company identifies a capacity issue, a distribution study is conducted, comparing the benefits and costs of several options, including:

- Load transfer to a less loaded substation or line;
- Capacity increase through upgrading lines or equipment;
- Building a new LVD substation to split the load; and
- Create an alternative connection to a different HVD or transmission line.

The Company's five-year investment plan in this sub-program is as follows:

FIGURE 157
LVD SUBSTATIONS CAPACITY CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
New substations	9	6	6	6	6
Existing substations capacity increase projects	5	8	8	8	8
Total	**14**	**14**	**14**	**14**	**14**
Unit Forecast					
	2021	2022	2023	2024	2025
New substations	5	3	3	3	3
Existing substations capacity increase projects	7	10	10	10	10

LVD Substations Capacity projects can involve building a new substation or rebuilding an existing one. Projects to increase existing substation capacity can include:

- Installing a new transformer position;

- Installing a new circuit position;
- Transformer upgrades;
- Fuse upgrades;
- Recloser upgrades;
- Breaker upgrades;
- Regulator upgrades;
- Switch upgrades; and
- Bus upgrades.

Planning Process

The Company uses several inputs and conduct analyses to aggregate multiple data sources to best evaluate electric loads on substation equipment. These analyses help to identify electric loads that exceed substation equipment ratings and capability limits. Substation equipment ratings and capability limits are established based on equipment manufacturer publications and incorporated into our planning process. Inputs include:

- MaxLoad System:
    - Substations Operations personnel record electric load data from substation equipment and substation metering points during onsite substation inspections, which is then input into the Cascade system; Cascade archives this data nightly into MaxLoad.
    - MaxLoad data is inputted into substation planning engineer spreadsheets and compared the substation equipment electric capabilities for annual loading analyses.
    - MaxLoad data is also analyzed directly from MaxLoad reports for individual project evaluation.
- SCADA
    - Electric load data is recorded remotely at frequent intervals from substation equipment in LVD substations where SCADA systems are installed.
    - SCADA data is also analyzed directly from the PI SDK Utility system for individual project evaluation.
- New Customer Load Data
    - New electric customer load data and existing customer load addition data are received from various departments that interface directly with customers.
    - Substation planning engineers analyze the new customer load data with the actual substation loads to determine if the new loads will exceed substation equipment ratings and capability limits.
- Distribution Automation Plans – Grid Modernization
    - Distribution Automation plans are received from the Grid Modernization and the LVD Lines Planning departments.

  - Substation planning engineers analyze the electric load transfers that will occur between each substation source to determine if the transferred load will exceed substation equipment ratings and capability limits.
- Electric Load Trends
  - The Company analyzes electric load data and trends to identify areas of electrical growth that are projected to exceed substation equipment ratings and capability limits.
  - The Company develops long range studies and project alternatives to determine strategic solutions that address the projected planning criteria issues and to optimize system reliability improvements and overall economic investment.
  - Chosen substation projects are implemented when the planning criteria issue is experienced; however, long lead time activities and purchases may be completed in advance of the actual substation project to avoid delays when the project is needed (e.g., new substation property acquisition, line easement acquisition, non-standard equipment purchases).

Project Prioritization and Selection

Once all the planning criteria issues are identified, substation projects are initiated and scheduled, based on an assessment of the projected system risk, projected customer impact, projected economic impact, regulatory requirements, and customer/contractual commitments.

Project planning is an ongoing continual process but plans for the upcoming year are finalized after summer peak loads are received and analyzed. Most substation peak loads occur between June and September, and few substations experience peak loads during winter months.

LVD Substations Capacity projects are often discussed as potential opportunities to explore NWS, and the Company has been exploring the potential for considering NWS as LVD substation capacity solutions in recent years. In 2017 and 2018, the Company ran a pilot program to explore whether or not an anticipated capacity upgrade at the Swartz Creek substation could be deferred through the use of targeted EWR and DR, under the premise that these targeted programs could reduce peak load on the substation and defer the capacity project. In 2019, the Company began a second pilot to further explore the use of targeted EWR and DR to defer an anticipated capacity upgrade at the Four Mile substation near Grand Rapids. In going through multiple pilot iterations, the Company has refined its selection criteria for identifying potential LVD substations where NWS can be considered, with criteria including the peak load reduction needed, the timeframe of the projected need, customer mix, and other factors. While these pilots are not administered by the Electric Planning organization, engineering planners play a role in identifying potential LVD substations to target. As the Company continues to develop lessons learned from these pilots, the Company expects to become better able to consider NWS more widely. The Company has already begun formally considering NWS in some of its concept approvals for projects in this sub-program. The Company is also engaged in an EPRI effort to develop an advanced planning software tool that will allow the Company's LVD circuit planners to examine NWS with power flow software that simulated hourly conditions for up to a 10-year period. Once available, this software will provide a comprehensive assessment of NWS, which will enable full understanding of the long-term costs and benefits of NWS.

Benefits

LVD Substations Capacity investments are necessary for the overall operation and reliability of the electric distribution system, by preventing future overloads and ensuring that the Company has adequate capacity on the distribution system to serve customer load.

iv. LVD New Business Capacity

Equipment and lines need to be added or upgraded for new customers or to maintain adequate service to existing customers when they increase their load beyond existing capacity. Historically, work in this sub-program was part of the LVD Lines Capacity sub-program, but it is now being considered as a separate sub-program to reflect the customer request-driven nature of the work. Projects in the LVD New Business Capacity sub-program are generally similar in scope to projects in the LVD Lines Capacity sub-program. Because work in this sub-program is driven by customer requests, the Company does not plan or prioritize projects far in advance in this sub-program.

Investments in new business capacity have a higher priority than upgrades to overloaded LVD equipment, due to the need to provide adequate voltage service to customers in the area where load growth is occurring, including those customers who are not increasing their loads.

The Company plans to invest between $12 million and $24 million in this sub-program each year over the next five years, given expected levels of new business activity, as shown below:

FIGURE 158

LVD NEW BUSINESS CAPACITY CAPITAL INVESTMENT

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
LVD New Business Capacity Total	**12.2**	**12.4**	**23.6**	**19.1**	**19.4**

Spending growth in this sub-program has been tied particularly to the growth of Michigan's cannabis industry in recent years, and this growth is projected to continue going forward.

Planning Process

New Business Capacity projects are evaluated using the same process as described in the LVD Lines Capacity sub-program.

When a capacity issue is identified by the circuit planner when evaluating a New Business Capacity request, the Company selects the best solution for addressing the potential overload. These potential solutions are the same as those listed for the LVD Lines Capacity sub-program: upgrading equipment, conductor upgrades, voltage conversion, and load balancing or transfer.

Because work in the New Business Capacity sub-program is driven by customer requests, projects are planned and prioritized based on the customer request date and the availability of resources required to complete the work.

v. LVD Transformers Capacity

The LVD Transformers Capacity sub-program consists of the purchase costs of distribution transformers and the associated first set expense. The purchase costs are allocated to the LVD Transformer sub-programs in New Business, Demand Failures, and Capacity. See the capital program for LVD Transformers New Business for additional details on the investment plan for this program.

vi. Interconnections

The Interconnections sub-programs fund work necessary to interconnect Company-built solar generation that is built as a result of the Company's integrated resource planning. This spending is categorized by whether it will require investment in HVD or LVD assets and whether that investment will be in lines or substations.

Over the next five years, the Company's investment plan in this sub-program is as follows:

FIGURE 159

INTERCONNECTIONS CAPITAL INVESTMENTS

5-Year Capital Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
LVD Lines Interconnections	-	-	-	0.3	0.3
HVD Lines Interconnections	-	0.2	0.2	1.5	3.0
LVD Substations Interconnections	-	-	-	0.3	0.3
HVD Substations Interconnections	-	-	-	1.5	3.0
Total	**0.0**	**0.2**	**0.2**	**3.5**	**6.5**

G. Electric "Other" Program

The Electric "Other" Program consists of additional capital investment to support the Company's distribution system that does not fall into one of the other five programs. The Electric "Other" Program includes three primary sub-programs: i) Computer and Equipment; ii) Tools; and iii) System Control Projects. The program also includes spending for the electric component of an Enterprise Corrective Action Plan.

i. Computer and Equipment

The Computer and Equipment sub-program consists of the capital costs to purchase and replenish computer equipment for electric distribution purposes. Based on historical average spending, the Company plans to invest $75,000 in this sub-program each year for the next five years.

ii. Tools

The Tools sub-program covers the purchase of new tools and replacement of tools that are worn, broken, outdated, and/or unrepairable when the tools are priced over $1,000 per item. Some examples of these tools covered in this sub-program include:

- Cordless cutting, crimping, and hammering/breaking tools;
- Concrete cutting/boring tools;
- Silica mitigation systems;
- Calibrated tools;
- Test meters/instruments;
- Diagnostic or locating equipment;
- Line segmenting (load drop/load pickup) devices;
- Wire pulling machines/accessories; and
- Specialty rigging, work lighting, pumping, or “bridging” and “matting” equipment.

Since 2016, this sub-program has also included outfitting new Company trucks (service bucket trucks, two-person buckets, and digger derricks) with truck tool packages, standard packages of essential tools to ensure that crews go into the field with appropriate equipment. The purchase plan for these truck tool packages is based on the Company’s fleet acquisition and deployment plan. As the Company expands its workforce, by expanding its apprentice programs for line and substation workers, and by adding workforces for HVD construction, underground work, and other areas, it will need to purchase more truck tool packages to accommodate this workforce.

The purchase of the tools covered in this sub-program is necessary to improve electric reliability, reduce risk of employee safety incidents and injuries, and improve employee productivity by having the proper tools available. Without these tools, the Company would not be able to perform routine compliance and maintenance work for customers.

The Company's five-year investment plan for the Tools sub-program is as follows:

FIGURE 160
TOOLS CAPITAL INVESTMENTS

5-Year Capital Plan (all values in $ millions)					
Investment Categories	2021	2022	2023	2024	2025
Truck Tool Packages	5.9	4.6	5.3	5.3	5.8
Other Capital Tool Purchases	3.0	4.4	4.8	5.1	5.3
Total	**8.9**	**9.0**	**10.1**	**10.4**	**11.1**
Unit Forecast					
	2021	2022	2023	2024	2025
Truck Tool Packages	178	143	153	137	137

Because not all trucks are the same, not all truck tool packages are the same either, so investments levels on truck tool packages do not always track with units counts on a 1:1 basis. This is particularly relevant as the Company expands its workforce to include dedicated personnel for HVD work and underground work, and correspondingly is expanding its fleet. As the Company begins this workforce expansion in 2021, it is making a large investment in truck tool packages during this year. The Company plans to continue making purchases for the underground workforce through 2023 and will make purchases for the HVD workforce from 2022 through 2025.

Specific capital tool purchases beyond the truck tool packages can vary from year to year based on the Company's needs at the time. Because this sub-program includes any tool over $1,000, many purchases are classified simply as general purchases. However, the Company does purchase some tools in broader categories as well. For example, the Company's other capital tool purchase plan for 2022 through 2025 includes the following each year, in addition to general purchases:

- Reconductoring trailers: $435,000
- Employee fall restraint kits: $480,000
- Substation bird mitigation equipment: $150,000
- Electric Field Lab ("EFL") Breaker Testers: $280,000
- EFL and HVD equipment testers: $100,000

Reconductoring trailers are used to support various LVD capital projects where reconductoring is required. Employee fall restraint kits are necessary to support safe work practices and meet OSHA requirements. Substation bird mitigation equipment is used on substations to supplement the work done through other animal mitigation investments. Breaker and HVD equipment testers are used to test equipment during substation maintenance work.

The Company assumes a $3 million baseline for annual investments in other capital tools, but then projects to invest more in 2022 through 2025 as part of a five-year plan to replace obsolete tools, including some of the specific tools mentioned above.

Benefits

Company crews require appropriate tools and equipment when in the field, both to ensure their own safety and the safety of the public, and to be able to complete their work in an expeditious manner to reduce outage times. Spending in this sub-program ensures that tools are replaced in a timely manner once they are no longer useful, and that Company trucks have appropriate tools with them at all times.

iii. System Control Projects

The System Control Projects sub-program consists of projects to improve management of the distribution system, by improving operations of control centers, streamlining operations, and improving remote control capabilities to improve safety and reliability.

Over the next five years, the Company's capital investment plan in this sub-program is as follows:

FIGURE 161

SYSTEM CONTROL PROJECTS CAPITAL INVESTMENTS

5-Year Capital Plan (*all values in $ millions)*					
	2021	2022	2023	2024	2025
HVD Operations Projects	2.7	2.9	3.0	2.7	2.3
Operating Technology Enhancements	1.0	0.6	0.6	0.6	0.6
Operations Center Modifications	2.9	1.4	0.4	-	-
Total	**6.7**	**4.9**	**4.0**	**3.2**	**2.9**

HVD Operations Projects

HVD operations projects enhance the operational flexibility of the HVD system and include installation and conversion of switches to isolate faults and minimize customer interruptions, with locations identified by the Company's System Operations Engineering personnel. The locations of some switching devices on the HVD system makes it difficult to isolate areas where a fault has occurred, increasing the number of customers interrupted, and the duration of interruptions, while repairs take place.

Projects in this investment category add automation to existing switches at these locations by converting them to MOABS, and add new switches with MOABS, reducing outage durations and isolating faults to smaller line segments with fewer customers. For example, it is possible for an outage on an HVD line section, which feeds multiple LVD substations, to interrupt service to 10,000 or more customers until repairs are completed. If an additional HVD switch is installed in this same line section, the number of customers experiencing the outage may be reduced to 5,000 customers via the use of the additional switch to sectionalize the affected HVD line.

This investment category can also include installation of line sensors to increase operational visibility on the grid, as well as equipment upgrades to handle higher load levels and minimize the number of customers as risk of interruption.

Projects are selected based on the following criteria:

- o Number of high load op-guides on which the switch appears (i.e., operational switching restriction);
- o The potential to increase line capability with a switch replacement;
- o Load level at which the switch presents power flow or N-1 criteria violations;
- o Switches that are on priority lists that have not been scheduled; and
- o Abnormal number of customer interruptions within the past few months that resulted in increased customer outage times.

Operating Technology Enhancements

Operating technology enhancements improve functionality and operations of the System Control Center ("SCC") in Jackson, the Distribution Control Center ("DCC") in Grand Rapids, and Work Management Centers ("WMCs") in Jackson, Grand Rapids, and Saginaw. Specific enhancements vary from year to year, but the Company plans at least two of these efforts per year. In 2021, the planned enhancements include:

- WMC upgrades for storm teams, adding technology for storm restoration management;
- Wire down/damage assessment mobile applications, used by field crews to report real time field conditions; and
- Badge scan check-in for storm response, to eliminate the need for a check-in/check-out specialist role.

For 2022, the planned enhancements include:

- Testing RTUs to support the integration of DERs into the Company's SCADA system, particularly third-party distributed generation; and
- Enhancements of resource management tools to support storm restoration, utilizing the Company's new OMS system that will go live in 2021.

Specific enhancements for future years will be planned throughout 2021 and 2022.

Operations Center Modifications

The purpose of these modifications is to provide sufficient working space for SCC and DCC personnel as the SCC and DCC take on increased responsibilities, particularly to enable collaborative engineering analysis and to optimize the WMC and DCC work environment and workflow between the WMC and DCC.

These modifications will also provide adequate space for storm restoration under the Company's ICS structure.

Additionally, the Company is investing in additional equipment and infrastructure to broaden the Emergency Operations Center beyond solely supporting storm response. Finally, the Company plans to install new video walls over two years, in 2022 and 2023.

iv. Enterprise Corrective Action Plan

Currently, the Company does not have a standard corrective action program or application. The Company manages corrective action in multiple ways between work groups, using a manual process and disparate reporting systems. This leads to inconsistencies in fixing problems and sustaining results, as well as, containment of problems rather than correction. Inconsistent issue categorization and investigations, lack of organizational focus in issue remediation, and minimal trend recognition are additional problems of not having a standard corrective action program.

To address this, the Company is implementing an Enterprise Corrective Action Plan, which will be a deliberate plan to identify and apply controls to manage risk processes and performance, the content collected through this process provides analytics that inform spend decisions for the health and well-being of the Company's operating systems. The scope of the project includes: (i) creating an intake process to record the issue as it is identified; (ii) implementing a method to do analytics; (iii) assembling content which becomes secure repository; (iv) setting up a standard issue and cause taxonomy; (v) assembling a repeatable risk-based remediation process; (vi) producing a risk-based evaluation with Quality Standards; (vii) invoking Statistical and Cognitive trending data queries; and (viii) creating a system of record for an audit trail.

The Enterprise Corrective Action Plan is business wide, supporting both the gas and electric businesses. The amount of spending allocated to the electric business is $56,000 in 2021 and $757,000 in both 2022 and 2023.

VIII. Five-Year Distribution Spending Plan – O&M

A. Intro to O&M

Operations and Maintenance ("O&M") spending on the electric distribution grid is projected to range between $221 million and $308 million over the next five years. The largest individual components of distribution O&M are Forestry and Service Restoration. While Service Restoration O&M is projected to remain flat from 2022 forward, the Company plans to increase Forestry O&M spending through 2025 and beyond to significantly improve reliability. Other increases in O&M are driven by increased targeted inspections and maintenance and by increased staffing costs as the Company increases its distribution workload.

FIGURE 162

5-Year Plan – O&M Programs								
	Actual			Plan				
All values in $ millions	2018	2019	2020 prelim	2021	2022	2023	2024	2025
Forestry	**51.9**	**53.3**	**54.8**	**84**	**94.4**	**100**	**117.6**	**120.4**
Service Restoration	**53.9**	**92.1**	**65.3**	**47.3**	**74.3**	**74.3**	**74.3**	**74.3**
Maintenance	31.9	28.4	26.6	25.3	33.8	36.2	38.7	39.1
Metering	12	12	10.5	17.3	17.3	15.3	15.7	16
Staffing	13.8	14	9.6	15	19.2	19.8	20.6	21.1
Planning and Scheduling	6.1	5.5	4.4	4.8	5.2	5.3	5.4	5.6
Smart Grid	5.3	4.8	4.3	5.6	6	5.3	5.4	5.6
Electric Planning	8.8	9.6	10	12.6	13.7	14.3	15.1	12.1
Electric Design	3.6	4.7	3.8	4.3	5.8	6.4	6.1	7.9
Support	3.9	5	5.9	5.2	5.5	5.5	5.6	5.7
Other O&M	**85.4**	**84**	**75.1**	**90.1**	**106.5**	**108.1**	**112.6**	**113.1**
O&M Plan	**191.2**	**229.4**	**195.2**	**221.4**	**275.2**	**282.4**	**304.5**	**307.8**

Each of these O&M spending areas is discussed in more detail in the following sections.

B. Forestry

The Company's Forestry line clearing program is responsible for optimizing the reduction of tree caused outage incidents to the electric system and for eliminating vegetation that hinders access to the Company's electric lines. The Company uses Integrated Vegetation Management ("IVM") along the Company's electric line ROW to accomplish these objectives. IVM is the practice of promoting compatible plant communities along the ROW using a combination of cost-effective methods, including chemical, cultural, mechanical, or manual treatments. The line clearing program is divided into LVD line clearing and HVD line clearing.

Trees are the greatest cause of interruptions to customers on the LVD system and a significant cause of outages or interruptions on the HVD system. Figure 163 below shows the history of tree-caused interruptions affecting customers from 2015 through 2020 including: (i) the number of interruption incidents; (ii) customers interrupted; and (iii) customer minutes of outage for tree-caused outages to the LVD and HVD systems.

FIGURE 163

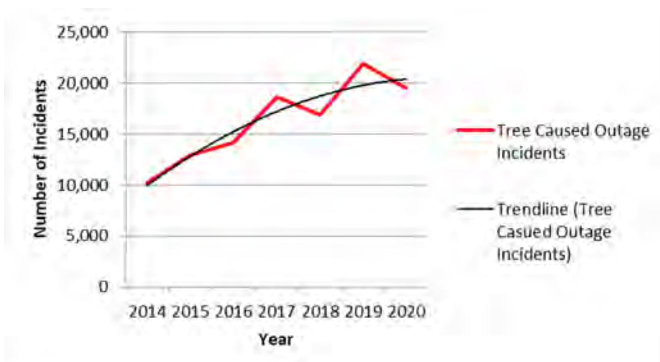
TREE-CAUSED RELIABILITY ALL VOLTAGES, 2015-2020 (INCLUDING MEDS)

	2015	2016	2017	2018	2019	2020
Incidents	12,912	14,125	18,634	16,860	21,853	18,598
Customers Interrupted	641,858	779,092	1,015,300	872,675	1,164,156	930,833
Customer Minutes	349,903,524	235,006,293	621,000,968	386,875,285	696,760,006	494,283,127

Figure 164 shows the trend of tree-caused outage incidents from 2014 through 2020 including MEDs. In this timeframe, outages due to tree contact have almost doubled, and were trending higher at historic funding levels. The Company's line clearing program is designed to minimize these occurrences, improve reliable service to our customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events.

FIGURE 164

TREE CAUSED OUTAGE INCIDENTS ON LVD AND HVD SYSTEMS, 2014-2020 (INCLUDING MEDS)



The Company's line clearing program also provides benefits not easily quantified, such as improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contacts with conductors. Enhancing the Company's line clearing program will ultimately result in less aesthetic impacts to customer properties and will improve public safety.

The Company's overall Forestry goal is to move toward a seven-year effective clearing cycle for the LVD system, and to maintain a four-year clearing cycle for the HVD system (as described in more detail below). In order to achieve this objective, the Company began incrementally increasing its spending on LVD line clearing in 2018 and 2019 (following the filing of the Company's 2018 EDIIP), and began a more significant increase starting in 2021, following approval by the MPSC in Case No. U-20697. Further increases are planned, pending further MPSC approval in subsequent years, until a seven-year effective LVD clearing cycle is attained. The Company plans to clear approximately one-seventh of its LVD line miles for the first time in 2025 and will then maintain that level of clearing in subsequent years in order ultimately to complete and maintain a seven-year effective cycle for the LVD system.

When the Company reaches a seven-year clearing cycle on the LVD system, the cost per line-mile will decrease as the time between clearings is reduced from current state. This reduction in the clearing cost per mile is expected to offset inflationary pressures on the line clearing O&M expense for several years. The Company projects significantly improved electric reliability for customers under the seven-year effective cycle by reducing tree-caused outages and decreasing the impact of storms on the electric system.

FIGURE 165

5-Year O&M Plan *(all values in $ millions)*					
Spending Categories	2021	2022	2023	2024	2025
LVD Line Clearing	***71.4***	***81.5***	***86.8***	***104.1***	***106.5***
LVD Contractor Full Circuit Clearing	54.9	64.0	68.3	84.2	86.7
Demand Work	2.7	2.7	2.6	2.6	2.5
Repetitive Outage	2.0	1.9	1.7	1.5	1.4
First Zone	1.9	2.0	2.2	2.4	2.5
Brush Control	2.9	2.9	3.2	3.5	3.5
CEMI Clearing	1.0	1.5	1.5	1.5	1.5
Salaries & Expenses	6.0	6.5	7.3	8.5	8.5
HVD Line Clearing	***12.6***	***12.9***	***13.2***	***13.5***	***13.8***
Maintenance Clearing	7.0	7.1	7.3	7.5	7.7
Brush Control	4.7	4.8	4.9	5.0	5.2
Demand Clearing	0.1	0.1	0.1	0.1	0.1
Noxious Weeds	0.1	0.1	0.1	0.1	0.1
Salaries & Expenses	0.8	0.8	0.9	0.9	0.9
Total Forestry Spending	**84.0**	**94.4**	**100.0**	**117.6**	**120.4**

As discussed in the Metrics section of this report, one of the Company's metrics is 'forestry cost per line-mile cleared.' This metric is calculated by taking the total cost of the Forestry program and dividing by the number of miles cleared (sum of LVD and HVD). In 2019, approximately 4,600 miles were cleared with total program spending of $53 million, giving a cost per line-mile cleared of approximately $11,500. Since this metric uses a blended cost between LVD and HVD, and includes all Forestry spending, it differs from the separate HVD and LVD costs per line-mile cleared.

i. LVD Line Clearing

The Company's LVD line clearing program manages vegetation along the primary and secondary LVD systems, including service conductors, clearing vegetation within a 30-foot-wide ROW to attain a minimum of 10 feet of separation between primary conductors and vegetation at the time of clearing and maintaining access along the ROW for other maintenance activities. As a part of scheduled full circuit line clearing, hazard trees, such as dead or dying trees that are within 20 feet of the edge of the ROW that are accessible to aerial lift trucks are removed, are unless the property owner requests otherwise. The Company plans to expand this hazard tree clearing beyond full circuit clearing to the other sub-programs listed below, to more comprehensively address hazard trees.

The Company's LVD line clearing program consists of several sub-programs, including: (i) program maintenance (full circuit clearing); (ii) repetitive outage zonal clearing; (iii) first zone clearing; (iv) CEMI clearing; (v) brush control; and (vi) demand clearing (customer requested work).

a) Program Maintenance (Full Circuit Clearing)

Program maintenance clearing is the primary, scheduled maintenance clearing work for the LVD system. This work is performed by contractors with qualified line clearance tree trimmer employees, in accordance with Michigan Occupational Safety and Health Administration requirements, on production-oriented contracts with the Company. Trees are cleared to attain at least 10 feet of clearance to primary conductors. Secondary voltage conductors and services are cleared of any tree limbs displacing or rubbing on these conductors. Brush (sapling trees and woody shrub species) are cut within the 30-foot ROW. Hazard trees (dead, dying, or mechanically stressed trees) within 20 feet of the edge of the ROW are removed when not objected to by the property owner.

This full circuit clearing is the focus of the Company's move toward clearing the LVD system on a seven-year effective cycle.

Full circuit clearing does not take place on a fixed schedule of circuits. Instead, the list of circuits for clearing is determined annually based on the most recent circuit performance data, using the Company's forestry reliability model. This model ranks circuits based on projected improvement in reliability, with a goal of maximizing reliability benefits at the lowest cost, using a number of input such as historical tree outage performance, tree density, and the average number of customers affected by a tree-caused outage compared to the historical tree outage performance of the circuit over a three-year period.

(1) Rationale for a Seven-Year Effective Cycle

A 2016 benchmarking study from CN Utility Consulting, Inc. ("CNUC") indicated that the industry average LVD clearing cycle is 4.9 years. That 4.9-year industry average clearing cycle results in an industry average of 0.241 tree-related outages per LVD mile per year. For comparison, over the period of 2011 through 2015, the same period used in the CNUC study, the Company average 0.415 tree-related outages per LVD mile per year. Conversely, a seven-year effective cycle for the Company would result in 0.27 tree-related outages per LVD mile per year, much closer to the industry average presented in the CNUC study.

However, in 2020, the Company's LVD line clearing program was commensurate with a 12.8-year clearing cycle. This cycle was actually an improvement over prior years – it was as high as 16.2 years in 2018 – and reflects that the Company is on the way to a seven-year effective cycle, as shown in Figure 166 below. The Company is ramping up to a seven-year effective clearing cycle, rather than moving to a seven-year effective clearing cycle immediately, because of limitations in how quickly contractors can increase their crewing. After 2025, it will take several additional years until all LVD circuits are fully on the seven-year cycle.

FIGURE 166

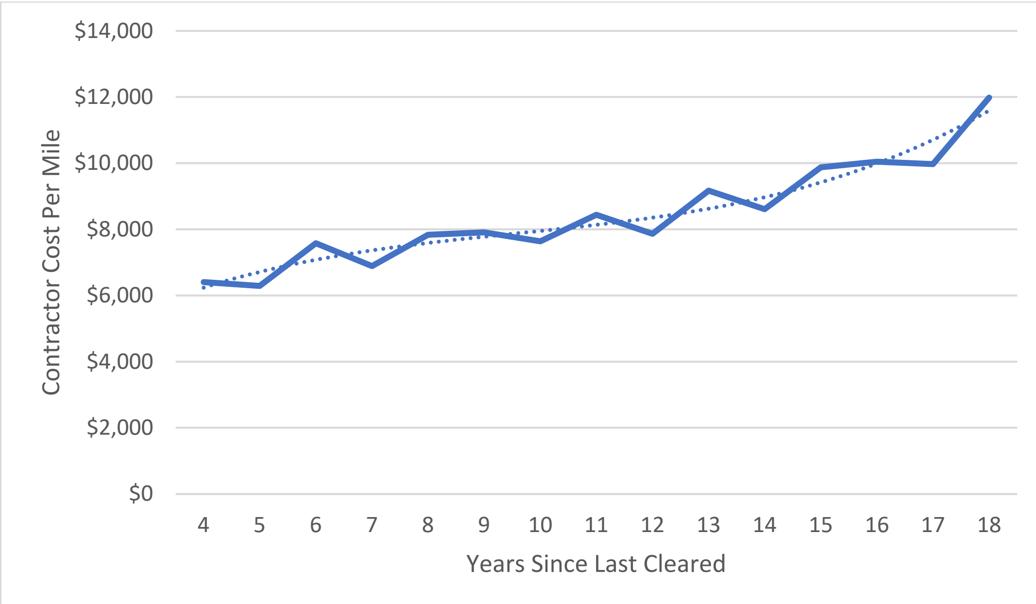
LVD LINE CLEARING RAMP-UP SCHEDULE

	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
$M	$38.36	$39.91	$41.08	$45.01	$71.43	$81.49	$86.84	$104.10	$106.52
Miles	3,503	3,218	3,518	4,120	5,223	5,986	6,346	7,654	7,914
Cycle (years)	14.9	16.2	15.2	12.9	10.1	8.9	8.4	7.1	7.0

A longer clearing cycle results in more complex clearing work, requiring removal of more biomass to achieve clearance to conductors. A study by Environmental Consultants, Inc., found that when the system is on a 14-year cycle, 20 feet of a tree's canopy must be removed to produce the required clearance. On a seven-year cycle, only 12 feet of canopy must be removed, making clearing less expensive on a per-mile basis, as shown in Figure 167 below. This shift also lessens the aesthetic impact of line clearing on customer properties, which reduces customer complaints.

FIGURE 167

CONTRACTOR COST PER LVD LINE-MILE BY YEARS SINCE LAST CLEARING



(2) Explanation of Seven-Year Effective Cycle

Under a seven-year effective cycle, it is not necessary to clear every circuit every seven years. Instead, the Company can take advantage of the fact that tree contact affects system voltages differently; tree contact with a higher voltage wire is more likely to result in a fault. Therefore, to achieve comparable levels of performance across all circuits, the Company can clear higher voltage circuits more frequently than lower voltage circuits.

The Company utilizes three major primary voltages on the LVD system. Each of these voltages have unique tree-caused outage characteristics. To optimize the number of outages occurring on the system, each voltage has a desired cycle of clearing (the 14.4/24.9 kV circuits have the shortest cycle, and the 4.8/8.32 kV circuits have the longest cycle). Using the miles of each voltage class on the system and the optimal cycle for each voltage, the "average" cycle length is seven years, or 14% of system miles as shown in Figure 168 below, with the average mileage for each LVD voltage class requiring clearing in a seven-year effective cycle shown.

FIGURE 168

LVD CLEARING SCHEDULE FOR SEVEN-YEAR EFFECTIVE CYCLE

Voltage Group	System Miles	14% Clearing Program – miles/year cleared	Effective Cycle for Voltage Group
14.4 kV	17,310	3,462	5 years
7.2 kV	9,900	1,413	7 years
4.8 kV	31,380	3,487	9 years

(3) Resourcing for Seven-Year Cycle

Continuing to progress toward a seven-year effective clearing cycle will require additional contractor resources. The Company, in partnership with its contractors, expects to continue meeting these crewing requirements. For example, in 2021, the Company is increasing total crewing from smaller Michigan based companies performing scheduled maintenance, which the Company plans to continue. In 2022, the Company anticipates expanding crewing for one of the four major line clearing vendors on the system. This will increase these companies' crewing component on the system to a similar crewing component that is in place for the other three major line clearing vendors.

In addition to increased crewing for LVD work, the Company can also use extended work weeks during favorable weather months. Because the Company has secured sufficient HVD crewing for the HVD clearing work plan, HVD crews can accelerate their work and then assist LVD crews with LVD clearing work.

b) Repetitive Outage Zonal Clearing

Repetitive outage work clears specific sections of circuits experiencing high levels of tree-caused outages, in order to reduce same-customer outages. On a monthly basis, the Company reviews sections of circuits to identify those with multiple, tree-related, non-MED outages within the previous 12 months. The Company also considers requests from LVD Planning when that organization identifies areas with large numbers of tree-caused outages, especially if formal customer complaints are received. Identified sections are scheduled for clearing based on system reliability impacts and resource availability.

c) First Zone Clearing

First zone work clears the section of a circuit from the substation outward to logical load concentration points ("LCP"). Typically, these are three-phase structures (poles with X, Y, and Z phasing) and any unfused laterals extending from this first zone. Although these zones may have lower outage frequency than other areas, outages that do occur impact a higher number of customers. This work reduces the likelihood of full circuit lockouts due to trees and provides a reliability benefit for all customers connected to the circuit. First zones are selected based on the previous 12-month tree-related outage history each fall when work plans are developed for the upcoming year. First zones are generally "mid-cycle," meaning they are included in the work plan only if the circuit has not been cleared in the last three years as part of full circuit clearing. Clearing of first zones is usually scheduled for the first and second quarters of the work plan year to maximize the reliability benefit to all customers of the circuit (because many outages occur in the second and third quarters of the year, completing this work in the first and second quarters helps get ahead of this).

d) CEMI Clearing

CEMI clearing work responds to customers experiencing high numbers of outages over the previous 12-month period and reduces the likelihood that these customers will experience similar outages going forward. CEMI clearing differs from repetitive outage clearing, as CEMI clearing is focused on the cumulative effect of all upstream LCPs from the customer's location, whereas repetitive outage clearing is focused on the number of outage incidents at a particular LCP. For CEMI clearing, no one individual LCP may be experiencing significant repetitive outage rates, but the cumulative effect of multiple upstream devices, each with just a few outages, results in the customer having many outages. CEMI clearing targets selected areas upstream of the customer location to reduce future tree-caused outages.

e) Brush Control

Brush control uses herbicide applications to treat brush within the ROW two to three years following full circuit clearing, particularly on rural and suburban circuits with higher brush densities in the ROW. This work reduces future stem volume, promotes the growth of compatible species within the ROW, and helps maintain accessibility for line maintenance or repair. Brush growing in or near wetlands or open water bodies is manually or mechanically cut instead of being treated with herbicides.

f) Demand Clearing

Demand work addresses emergent vegetation threats to the LVD system. Emergent vegetation threats are identified predominantly by customers calling in personal observations around their homes, from forestry operations personnel, and from other electric operations employees performing duties in the field. The Company's forestry operations personnel review these requests in person, or through phone conversations, with the reporting party to validate the emergent nature and the likelihood of an outage. Work that can wait until maintenance clearing will be performed is delayed, but validated threats to the system are addressed based on system reliability impacts and resource limitations.

g) Drivers of LVD Unit Costs

Several variables affect the cost per mile of LVD line clearing, particularly cycle length, redirection of labor to less productive work, labor costs, and regulatory compliance. The impact of cycle length was discussed above and is one reason for the Company's plan to reduce cycle length, as longer cycles lead to increased amounts of biomass that must be removed, leading to increased time needed to clear a circuit and therefore increased labor costs. This issue is correlated with the redirection of labor to less productive or less efficient work: since longer cycles lead to more vegetation encroaching on circuits, more customers experience repetitive outages, leading to more repetitive outage clearing and CEMI clearing that crews must prioritize. This clearing work is less efficient and less cost-effective than full circuit clearing.

While the Company expects to be able to secure sufficient workforce resources to implement its plan, scarce workforce resources are nevertheless driving cost increases, as a tightening of the skilled trades labor market leads to increasing labor expense to retain qualified forestry workers.

Environmental regulatory constraints affecting forestry work have also increased. In order protect numerous threatened or endangered species in the Company's service territory, forestry work must be suspended or restricted during certain times of year, impacting unit costs.

h) Benefits of LVD Line Clearing

Clearing trees benefits customers by reducing outages and decreasing impact of storms. Clearing the ROW allows easier access to lines, resulting in faster restoration when an outage occurs. For the three major distribution voltages used on the LVD system, the benefit of clearing is demonstrated in Figure 169 and Figure 170 below. On average, SAIFI and SAIDI both improve substantially in the year that clearing is completed with more benefit seen on circuits cleared early in the year than circuits cleared at the end of the year. This trend of improved performance continues in subsequent years before eventually reversing further into the future.

FIGURE 169
SAIFI IMPROVEMENT POST-CLEARING

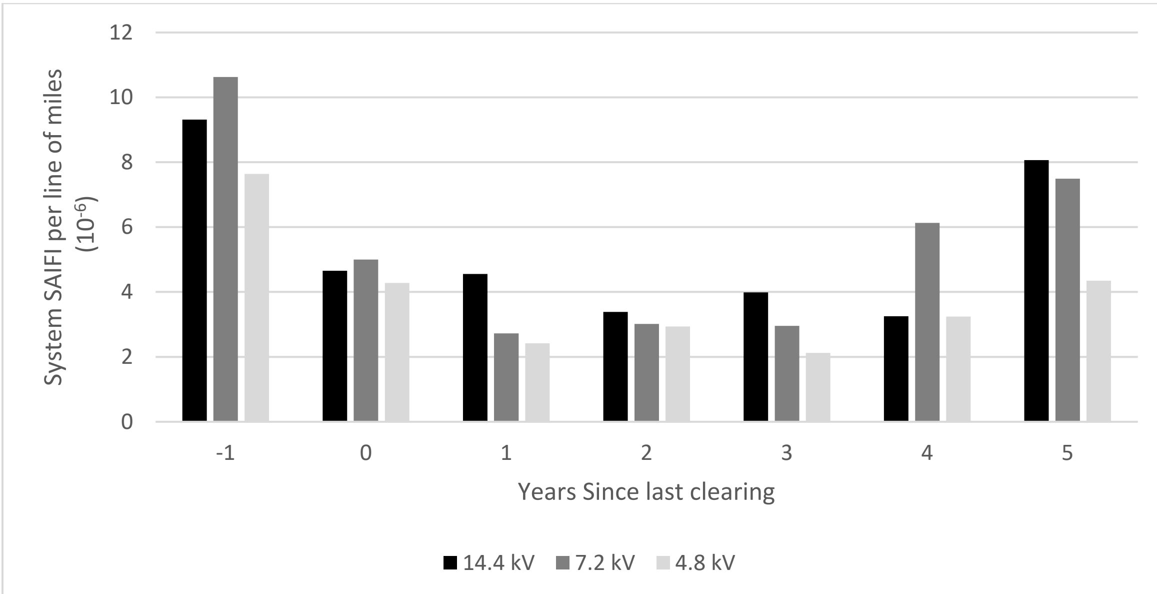
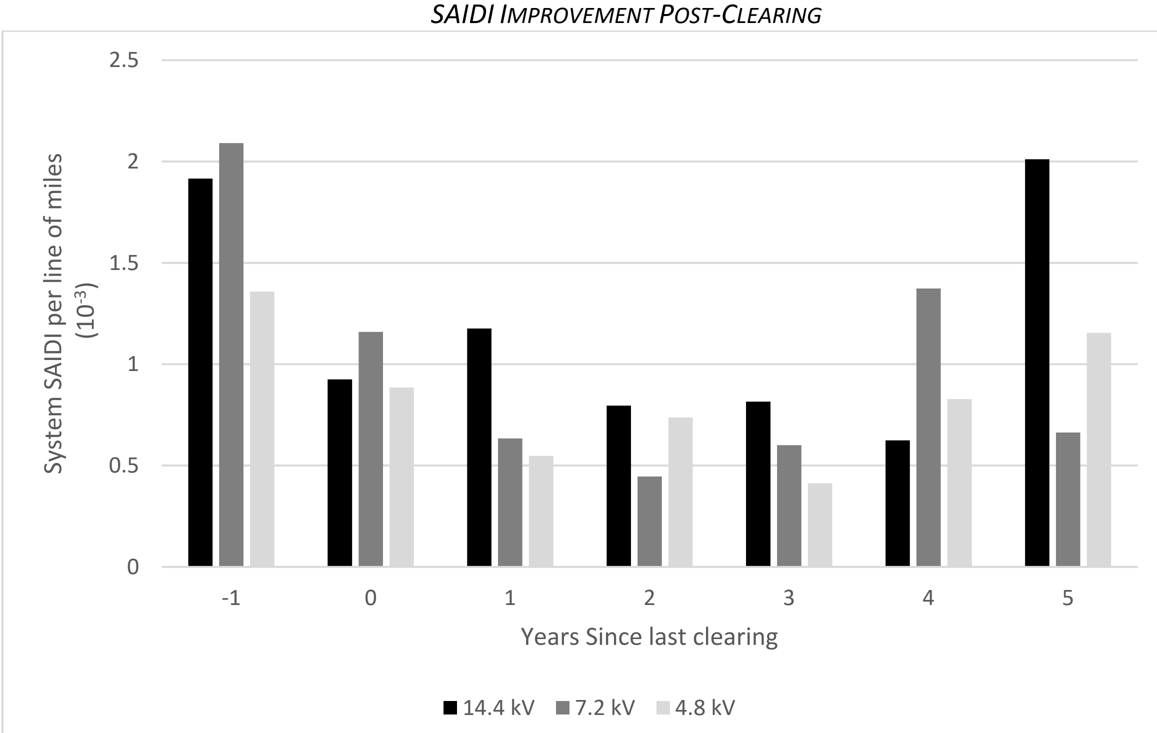


FIGURE 170
SAIDI IMPROVEMENT POST-CLEARING



ii. HVD Line Clearing

The HVD line clearing program manages vegetation along the Company's high voltage systems. There are two major voltages on the Company HVD system: 46 kV and 138 kV. The Company clears vegetation within an 80 to 120-foot-wide ROW for these voltages to attain a minimum of 15 feet of separation for 46 kV lines and 20 feet of separation for 138 kV lines, between conductors and vegetation at the time of clearing. The Company also manages vegetation within the ROW to maintain accessibility along the ROW for maintenance and repair of the line. During scheduled maintenance line clearing, the Company identifies and removes hazard trees up to 40 feet from the edge of the ROW.

The Company's HVD line clearing program includes these sub-programs: (i) maintenance tree clearing; (ii) brushing and herbicide treatment; (iii) demand clearing; and (iv) noxious weed control (grass and weed mowing to meet local ordinances).

a) Maintenance Tree Clearing

The Company's HVD maintenance tree clearing work consists of scheduled cycle maintenance activity for trimming and removing trees within the ROW corridor and includes hazard tree removal outside of the ROW. HVD rights-of-way are typically cleared 40 feet on either side of the centerline to remove all tree species and shrubs that inhibit ROW access. Trees growing along city streets or landscaped residential properties may be trimmed to attain a minimum of 15 to 20 feet of clearance instead of removal. A tree outside of the ROW is considered a hazard tree if it is tall enough to strike the HVD line if it fell and if it is dead and/or structurally weakened.

b) Brush Control

The Company conducts brush cutting and herbicide treatment in HVD rights-of-way to reduce the volume of small trees growing within the ROW before they grow to a height that may interfere with the line. This work also allows line worker crews to access equipment for repair or replacement. Brush control work is: (i) completed on a four-year cycle schedule; (ii) reduces future stem volume; (iii) promotes the growth of compatible species within the ROW; and (iv) supports or maintains habitat needed for several endangered, threatened or rare species of plants and animals.

c) Demand Clearing

The Company's demand clearing work addresses emergent vegetation threats to the HVD system. These threats are identified by HVD vegetation inspections and by helicopter patrols of the HVD system. Demand clearing work most often involves partially uprooted trees that are leaning toward the line that will eventually fall onto the line. These situations require immediate remediation to prevent an outage.

d) Noxious Weed Control

The Company's noxious weed control work maintains compliance with local ordinances for maintaining vegetation on HVD rights-of-way in predominantly urban areas. These ordinances do not permit vegetation growth above a specified height, requiring three to six mowing cycles of affected rights-of-way each year, with variation due to rainfall and temperature.

e) Recent HVD Line Clearing Performance

FIGURE 171 below shows the Company's recent historical performance for line clearing work on the HVD system. From 2017 through 2020 (4-year period) the Company targeted 4,339 miles of the system for clearing and achieved clearing 4,305 miles for this timeframe, maintaining a four-year clearing cycle.

FIGURE 171

HVD LINE CLEARING TARGET AND COMPLETED MILES

Year	*Target Miles*	*Completed Miles*
2017	1016	1019
2018	1150	1081
2019	1064	1100
2020	1065	1103

f) Drivers of HVD Unit Costs

Several factors have impacted HVD line clearing unit costs in recent years. In particular, since 2015 the Company has had to expand its hazard tree removal in response to emerald ash borer ("EAB") activity. This invasive species attacks ash trees with nearly 100% mortality and has killed approximately 10% of all trees in the Lower Peninsula. Costs have also increased to meet new regulatory requirements for herbicide applications.

As with LVD line clearing, labor costs affect unit costs for HVD line clearing as well, particularly as the Company pays to retain a Michigan-based workforce for HVD lines clearing.

g) Benefits of HVD Line Clearing

By maintaining a four-year cycle for HVD line clearing, the Company is effectively managing the number of HVD line outage incidents from trees within the ROW. Outages on the HVD system can have broad impacts and can affect large numbers of customers. In the years 2015 through 2019, the average customer impact of a tree outage on an LVD circuit was 45 customers and the average customer impact of a tree outage on an HVD line was 670 customers. HVD line clearing benefits customers by mitigating the amount of these high customer impact outages. Additionally, outages on the HVD system often take longer to repair, and therefore have higher customer minute impacts. Maintaining a four-year HVD line clearing cycle is necessary to minimize the impact of HVD tree outages to the LVD system and customers.

C. Service Restoration

The Company's Service Restoration O&M program prepares for and executes work related to public emergencies and restoration activities for all outage categories, including MED and Catastrophic Events. This work includes addressing hazards such as broken poles, wire downs, and emergency orders. In addition to the work plan projections, this program includes the non-capital portion of standby costs and on-call costs for field resources. The program also includes operating and maintenance of the two-way customer communications systems related to outage communications and alerts, and media costs such as radio advertisements related to wire downs and generator safety, to remind our customers and the public of precautions to take during an emergency. This program supports customer claims associated with operating and maintenance restoration or emergency response activity.

The Company currently plans to spend $47.3 million on Service Restoration in 2021, based on the outcome of the Company's 2020 electric rate case. For the remainder of the five-year period through 2025, the

Company plans to spend $74 million per year on Service Restoration. This projection is based on a three-year average of the Company's spending on Service Restoration from 2018 through 2020, adjusted for inflation. The Company believes that this level of spending represents true service restoration needs, and, as discussed below, will allow the Company to better plan for storms to reduce CAIDI.

FIGURE 172

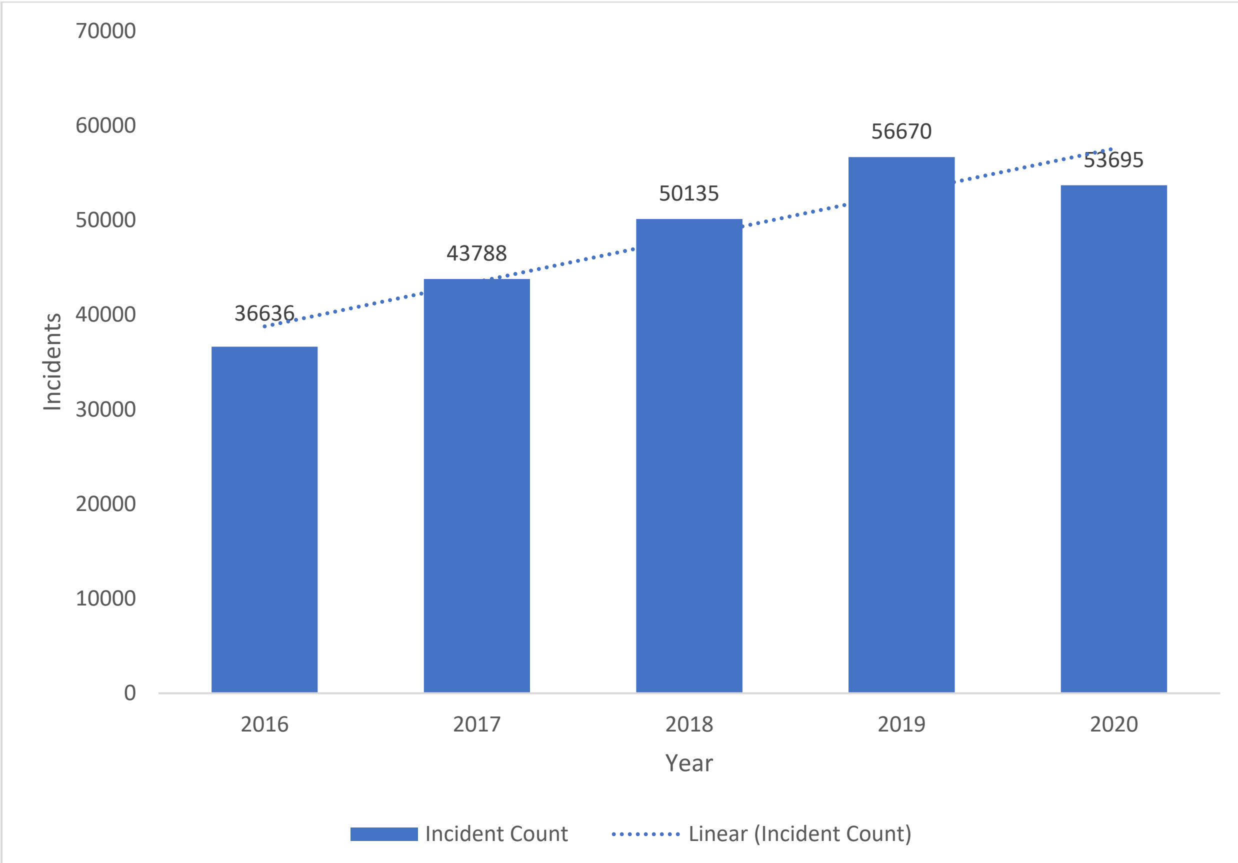
CALCULATION OF PROJECTED SERVICE RESTORATION EXPENSES

$M	2018 Actual	2019 Actual	2020 Prelim	3-Yr Avg	2021 Inflated	2022 Inflated
Spending	$53.9	$92.1	$65.3	$70.5	$72.4	$74.4

In recent years, the Company has experienced worsening weather, as measured by frequency and strength of wind gusts, and the Company has correspondingly seen an increase in incident count on the system. As shown in

Figure **173** below, incident count has increased by approximately 20,000 since 2016 and has remained above 50,000 every year since 2018.

FIGURE 173
INCIDENT COUNT, 2016-2020, INCLUDING MEDS



The Company expects that its investments to reduce SAIFI will reduce the number of incidents over the next five years. However, continuing to spend at a consistent level in the Service Restoration program will allow the Company to respond more quickly to MEDs and catastrophic storms, which will be necessary to deliver desired CAIDI improvements and improve the customer experience.

At the same time, the Company has been exploring process optimization opportunities for Service Restoration to improve efficiency and eliminate waste. In 2019, the Company's Operations Performance group began identifying opportunities, and in 2020 several initial waste elimination efforts were implemented, including:

- Optimizing storm related staffing positions to eliminate positions no longer needed;
- Automating standard reports to reduce Documentation Unit Leader support;
- Streamlining the process to identify crew status for real-time planning; and
- Implementing real-time storm planning dashboards to visualize and prioritize work assignments.

Going forward, additional waste elimination opportunities are being explored, including:

- Building predictive models to identify and fix system failures before they happen, and pre-staging resources to enable rapid response;
- Implementing a Damage Assessment mobile app to quickly understand the scope and magnitude of work to effectively manage resources; and
- Enhancing real-time planning capabilities to prompt the right teams to make the right decisions at the right time (e.g. declare storm, activate damage assessment & wire down operations, establish field control, demobilize mutual aid and contractors).

<u>Current Service Restoration Capabilities</u>

In normal operations, the Company assumes availability of approximately 140 crews and 60 electric service workers ("ESWs"), which can vary based on vacations, sick leave, and training. Some crews must remain in their home headquarters to respond to emergent issues within their area that are not storm related. Typically, this level of field resourcing allows for approximately 300 incidents or 18,000 customer outages to be addressed in a single 16-hour shift additional resources are needed.

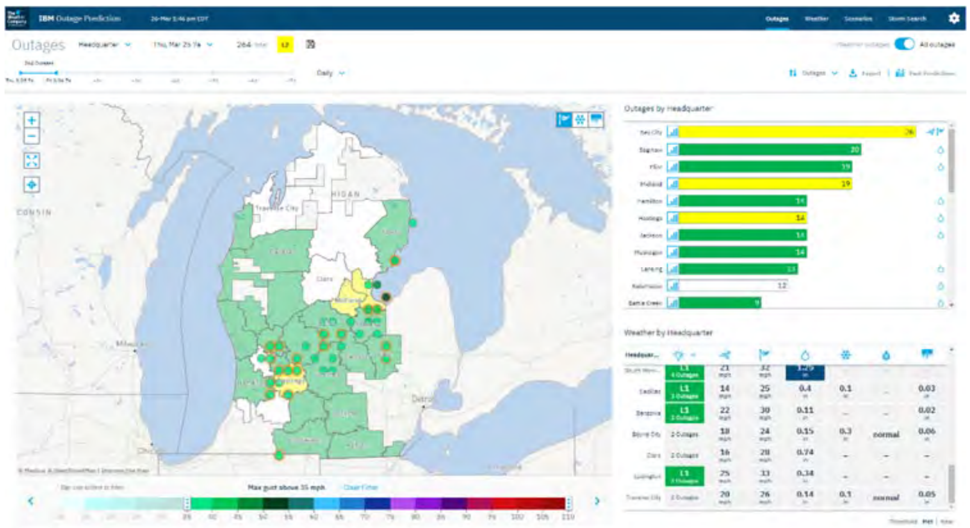
The Company uses an Incident Command System ("ICS") to address emergency situations, and storm response is always addressed through an ICS. Within the Company's ICS, crew-to-dispatcher ratio is important. Each experienced dispatcher can handle 15 to 20 points of contact with field personnel. To control the number of points of contact, field leaders obtain work from dispatchers. Field leaders will then have five to seven crews reporting to them to issue work, which allows for a greater span of control and more efficiencies with field personnel. Through January 31, 2021, the Company used an outage prediction model called Storm Impact Analytics ("SIA"), with joint participation from Telvent Data Transmission Network ("DTN") to streamline the process for placing resources on call. After that date, the Company switched to using IBM's Outage Prediction model, following a competitive RFP process.

To manage risk in advance, the Company plans for weather-related events utilizing the Outage Prediction model from IBM. A screenshot example of this is shown in Figure 174 below. The Outage Prediction model was developed and first implemented in early 2021. This model allows current weather patterns, past outage history and machine learning to determine the approximate number of customers that will potentially be impacted.

The Outage Prediction model uses weather forecasts – including maximum wind gust forecasts – for the next seven days to project a number of outages by service center region, which allows the Company to better predict where resources will be needed, including whether or not resources will need to be on call in an area. The model also allows the Company to run what-if scenarios, such as increased wind or increased icing, to better plan for worst-case situations.

FIGURE 174

OUTAGE PREDICTION MODEL SCREENSHOT

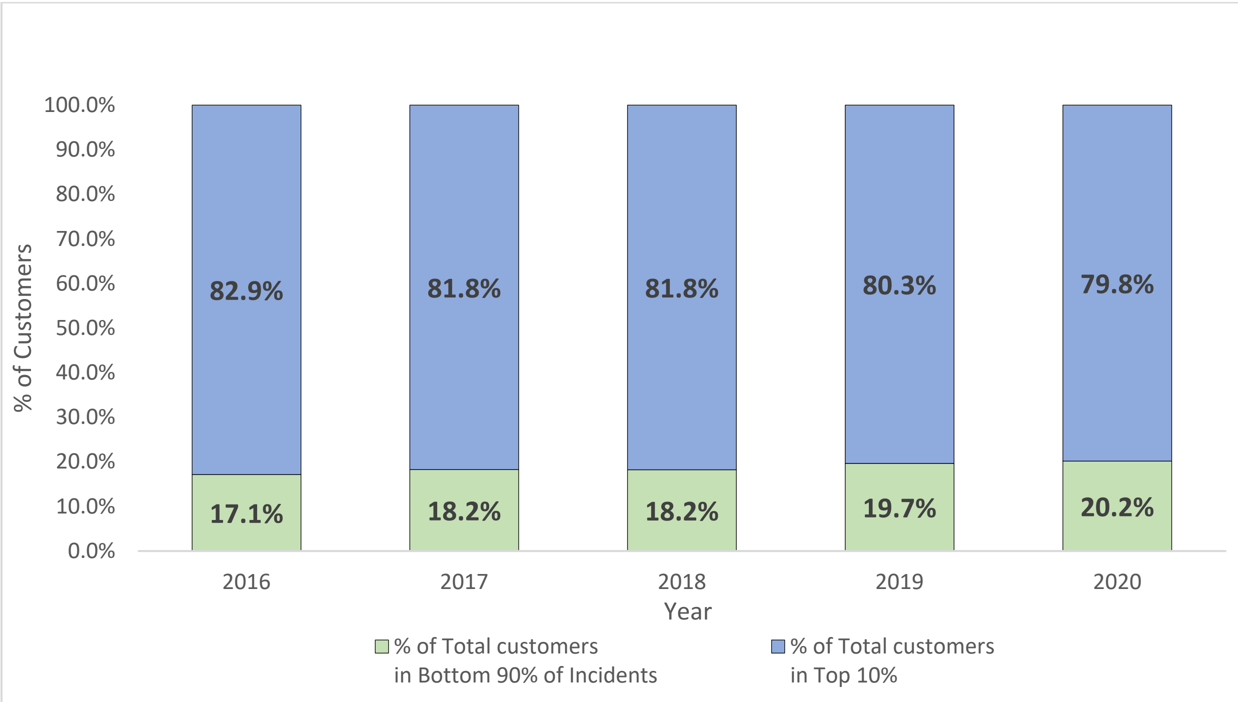


Once the threshold of 300 incidents or 18,000 customer outages is exceeded, the Company must use off-system resources to perform service restoration. In order to progress toward a CAIDI target of 180 (refer to Figure 4 of this report), the Company needs approximately 200 total crews to respond to an event with more than 300 incidents or 18,000 customer outages, or 60 incremental crews above the Company's usual level of 140. To truly realize the benefits of available crews, the Company needs to pre-stage them in advance of anticipated major events. Pre-staging 200 crews is estimated to cost $7.2 million, but for events with more than 300 incidents or 18,000 customer outages doing so would improve CAIDI by 7%-10%.

The Company's ICS work has resulted in dividing storm restoration into two components: pre-staging and restoration work. Pre-staging for a predicted weather event requires placing the necessary resources (such as crews and support) on standby for the pending event or on site in preparation for the event. Because 10% of large customer outages impacted approximately 80% of customers during storm declarations, as shown in Figure 175 below, the Company focuses on Isolate, Restore, Repair ("IRR") along with circuit lockout. This means that field resources secure hazards as a main priority by first isolating damaged sections of the grid to allow safe work to begin and restore as many customers as possible.

FIGURE 175

PERCENTAGE OF CUSTOMERS IMPACTED BY LARGE OUTAGE EVENTS, 2016-2020, INCLUDING MEDS



Once predictions are made in the IBM Outage Prediction model, as discussed above, pre-staging for a predicted weather event requires placing the necessary resources (such as crews and office support) on standby for the pending event or on site in preparation for the impact. This includes both Company crews and any needed off system resources, described below. This represents a kind of insurance: if a predicted storm does not materialize or is less severe than expected, then some of the money spent on pre-staging may be unrealized, but this offsets the risk of being unprepared for widespread outages and having to secure resources after the fact.

The potential outcomes from pre-staging is illustrated by two different events in 2020:

- On January 11, 2020, an icing event caused damage on the Company's electric system resulting in downed electric lines and numerous outages. The National Weather Service forecasted greater than 0.5 inches of ice to accumulate in several major cities in Michigan. The Company's weather provider DTN had high confidence of 0.5 to 0.75 inches of ice accumulation and potential for wind gusts to reach 50 mph in some areas. The forecasted storm impact was similar in scale to the catastrophic ice storm of December 2013. The Company initiated an all-hands situation; 177 contract crews were requested, many from out of state, and 161 Company crews were pre-staged. Although the ice storm was less severe than predicted, the event ultimately impacted 42,000 customers and caused over 500 incidents. Because of the pre-staging, the Company's restoration performance met the MPSC's service quality restoration target, meaning benefits were realized even though the storm was not a severe as forecast.

- In June 9-11, 2020, three rounds of severe thunderstorms caused 305,000 customers to lose power with 6,200 outages and 5,300 wire-downs. During these catastrophic conditions, wind gusts were recorded between 66 and 75 mph across several headquarters throughout the state. The Company leveraged its ICS to organize restoration activities and activate off system crewing from inside and outside the state. In total, nearly 1,400 line workers assisted in restoration activities despite the COVID-19 pandemic, which required additional safety measures to protect workers.

Off System Resources

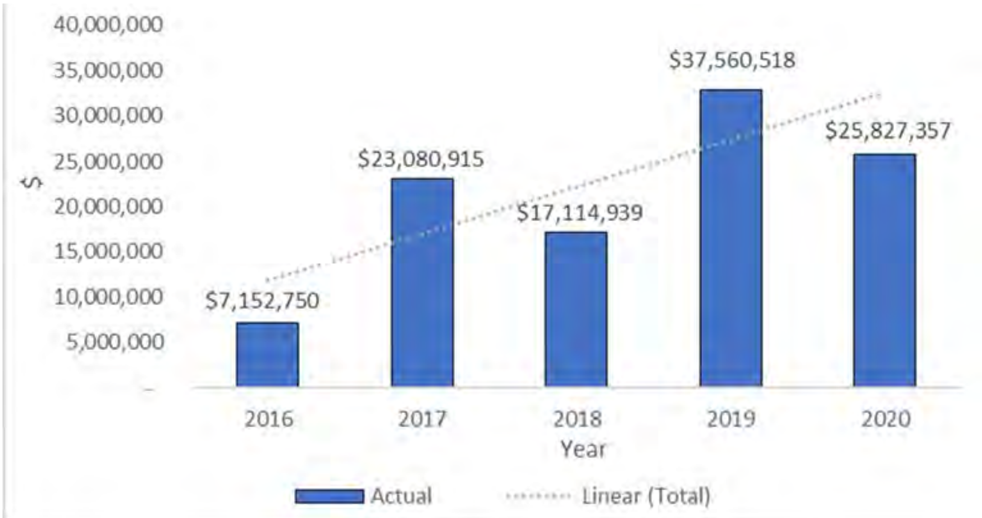
When weather increases the number of incidents and the Company needs to pre-stage resources, additional crewing is needed beyond the Company's regular workforce. In these cases, the Company will reach out to off system crews to assist in providing the necessary resources to achieve the targeted restoration time for customers. Off system crews are primarily obtained as necessary from other utilities, municipalities and contractors, and are deployed when all Company resources are engaged, and the incident count is greater than current crew capacity can address in a timely manner.

Most of these crews are from out of state and require lengthy travel time and lodging during their stay, which increases the restoration cost, especially in the more severe restoration events. There is no guarantee that the host utility will receive all the resources that are requested as the sending utility may be faced with the same weather event. Without the assistance provided by these crews, restoration time would be delayed. If these crews are not obtained early in the pre-staging process, other utilities impacted by the same or similar weather events will request and could secure these resources.

Costs are higher for off system crews than for the Company's crews, because costs include per diems, travel, meals, hotel, and staging costs for parking vehicles during rest periods. From the time of activation, off system crews are paid at a higher rate for all hours worked and while on standby. As a result, off system crew expenses are a significant part of the Company's overall Service Restoration expenses, as show in Figure 176 below.

FIGURE 176

ANNUAL OFF SYSTEM RESOURCE COST



Although costs are high for off system resources, they are necessary for responding to significant weather events. It would be less cost-effective for the Company to permanent maintain a large enough workforce to completely independently respond to catastrophic events.

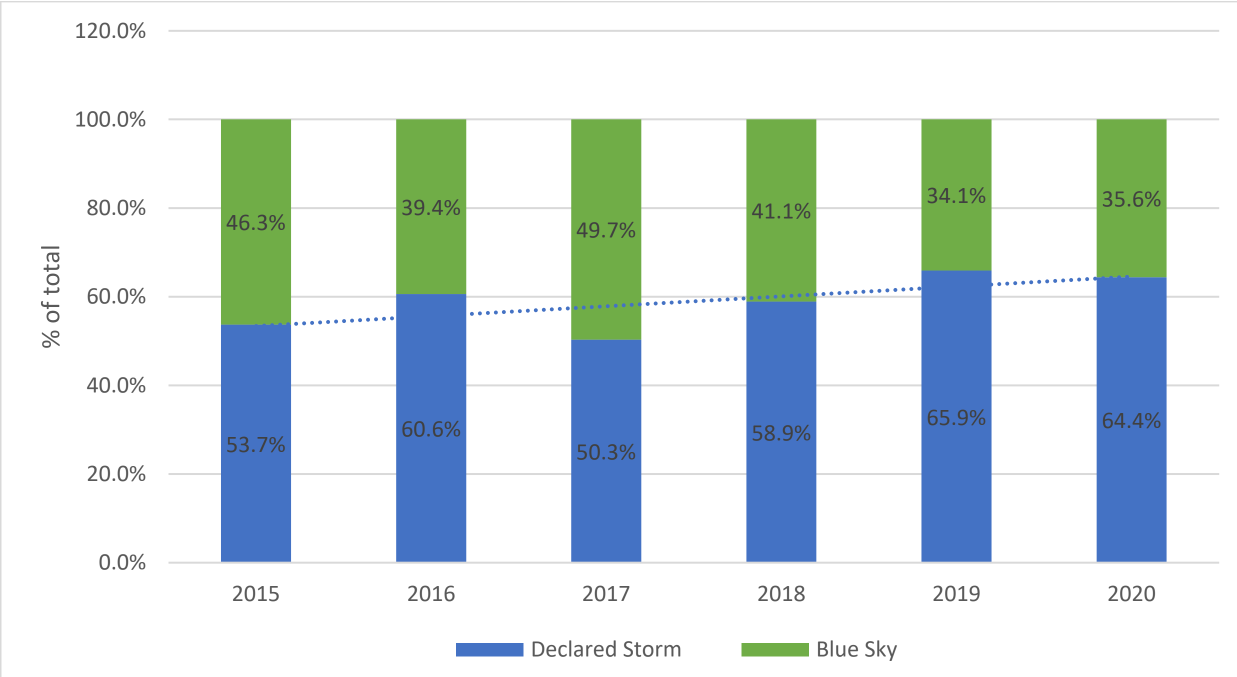
<u>Benefits</u>

In order to provide continued improvement in restoration activities for customers, adequate staffing and field resources for prestaging purposes are necessary to shorten the duration of outages while safely working with police and fire departments to manage wire-down and large storm events with significant customer impact.

Service Restoration is a key program for managing CAIDI, which is a component of SAIDI. Since 2015, the Company's blue sky CAIDI performance has improved. However, declared storms have increased from a 54% contribution to CAIDI to a 65% contribution, as shown in Figure 177 below. To improve CAIDI during storms, the Company must improve its use of prestaging of crews in response to anticipated storms. Therefore, even as the system experiences fewer incidents as SAIFI is lowered, the Company plans to maintain its total spending level for Service Restoration in order to ensure effective response to storms and reduce CAIDI in line with the Company's overall SAIDI target.

FIGURE 177

CAID CONTRIBUTIONS FROM BLUE SKY VS STORMS



D. Other O&M

While Forestry and Service Restoration are the two most prominent O&M programs supporting distribution reliability, the Company has other O&M spending that includes the Company's ongoing distribution operations and engineering functions, plus funding for certain internal organizations that support both of those functions.

For purposes of this report, this other O&M is classified into the following functions for Electric Operations:

- Maintenance;
- Metering;
- Staffing;
- Planning and Scheduling; and
- Smart Grid.

Electric Engineering O&M is classified into two functions: Electric Planning and Electric Design. A final function, Support, includes spending to support both Electric Operations and Electric Engineering.

i. Maintenance O&M

Maintenance O&M includes 14 spending areas, each focusing on enhancing reliability and safety through inspections and repairs of equipment. The Company's five-year spending plan for Maintenance O&M is as follows:

FIGURE 178
MAINTENANCE O&M SPENDING

5-Year O&M Plan (all values in $ millions)					
	2021	2022	2023	2024	2025
LVD Lines Reliability	0.8	1.3	0.7	0.8	0.8
HVD Lines Reliability	0.1	0.1	0.1	0.1	0.1
LVD Substations Reliability	2.6	3.7	4.2	5.2	5.2
HVD Substations Reliability	2.2	2.9	3.4	3.6	3.6
HVD Lines Demand	0.8	1.0	1.0	1.1	1.1
LVD Substations Demand	3.0	4.7	5.6	6.4	6.4
HVD Substations Demand	2.2	3.8	4.5	5.0	5.2
Corrective Maintenance	4.2	4.9	4.9	4.9	4.9
Staking	3.0	3.7	3.8	4.0	4.1
Streetlighting	1.2	1.8	1.8	1.8	1.8
Service Calls	4.4	5.0	5.0	5.0	5.0
Alma Equipment Repair	1.0	1.0	1.0	1.0	1.0
Tools	1.4	1.6	1.6	1.7	1.7
Field Operations Expenses	2.0	2.6	2.6	2.6	2.6
Total	**25.3**	**33.8**	**36.2**	**38.7**	**39.1**

Beginning in 2021, the Company is increasing its spending on Maintenance O&M to increase its substation inspection and maintenance activity. In the late 1990's and early 2000's, the Company developed maintenance standards for substation equipment based on vendor recommendations, industry best practices, and Company experience. However, reduced O&M spending in subsequent years prevented much of the needed maintenance from being done. Preventative maintenance was limited to station batteries, protective relays, and, on a limited basis, power transformers and single-phase step regulators. Other major equipment (circuit breakers, load tap changers, reclosers, and circuit switchers) and smaller equipment (potential transformers, station power transformers, capacitive couple potential devices, lighting arresters, capacitor banks, switches, etc.) were operated in a run-to-failure mode.

As a result, the Company has a backlog of orders for substation inspections and demand work:

- Backlog of demand orders prior to increasing substation maintenance:
  - LVD Substations – 1,160 orders (46,700 man-hours); and
  - HVD Substations – 550 orders (22,200 man-hours).

- Backlog of substation inspection orders prior to increasing inspections:
  - LVD Substations – 5,538 orders (74,300 man-hours); and
  - HVD Substations – 1,861 orders (25,400 man-hours).

From 2017 through 2019, SAIDI attributed to substations trended upward due to this backlog. While substation outages are less frequent than LVD lines outages, they affect more customers when they do occur. Of the unplanned substation equipment outages from 2014 through 2018, 67% of them were attributable to equipment issues, and while not all of these outages resulted in interruptions to customers, the Company calculates that a 50% reduction in outages through improved inspections and maintenance would save over 3 SAIDI minutes per year system wide. In addition, the system could be operated much more closely to its design parameters, resulting in more efficiency and fewer demand repairs.

The Company plans to phase in spending to hire additional substation maintenance personnel beginning in 2021, with $2.7 million in incremental spending each year from 2021 through 2023, resulting in an overall increase in spending of $8.1 million. This increased spending is allocated across the LVD Substations Reliability, HVD Substations Reliability, LVD Substations Demand, and HVD Substations Demand O&M spending areas.

a) LVD Lines Reliability

LVD Lines Reliability O&M supplements the LVD Lines Reliability capital program by funding activities that promote the long-term safe and reliable operation of the LVD system, including maintenance and costs associated with new grid devices and connected equipment. New equipment includes new devices on the LVD system such as line sensors, regulator controllers, capacitor bank controllers, and automatic transfer reclosers. Additionally, O&M will cover firmware upgrades, communication costs, and troubleshooting in case of failed equipment. LVD Lines Reliability O&M consists of three categories: (i) padmount inspections; (ii) assessment findings and repetitive outage mitigation; and (iii) automation device/equipment performance.

The exterior of pad mounted equipment is visually inspected each year for any signs of leaking oil, holes that expose electrical components, or missing labels. If found, the holes are patched, and labels are replaced. If equipment is irreparable, replacement of equipment is done under the LVD Lines Demand Failures sub-program. In addition to the corrections, the labor for padmount inspections is also included in this O&M category.

LVD security assessments are also addressed here. As described in the LVD Lines Demand Failures capital sub-program, all LVD circuits are inspected on a six-year cycle for public and employee safety, and for reliability concerns. Issues identified that are not capital components are addressed through this O&M spending. In addition to security assessments, repetitive outage issues are also identified that are not able to be addressed under the LVD Repetitive Outage capital sub-program. Some examples include:

- Replacing a fuse link to put a fuse back into service or correct system protection issues, including device reach and coordination between devices;
- Moving a jumper on a line or device to balance load among phases or reconfigure the customer's service;
- Bringing assets up to existing standards, such as by moving lightning arrestors to the load side of the transformer cutout;
- Replacing damaged or stolen components, such as sections of copper down grounds that have been stolen;
- Adding or correcting existing labels for devices in the field to match Company records; and
- Adding animal mitigation due to past animal related outages.

Maintenance of automation devices and connected equipment is required in order to maintain the benefits of these devices and equipment. The Company can remotely monitor this equipment to identify when it is not functioning properly. When this occurs, the device or equipment is investigated to determine the cause. If equipment or device is irreparable, replacement of equipment is done under the LVD Lines Demand Failures sub-program.

Spending for LVD Lines Reliability O&M is increasing in 2021, compared to recent historical levels, primarily because of the addition of spending on automation device and equipment performance. The Company is addressing a backlog of capacitor bank device anomalies in 2021 and 2022, after which spending will decrease.

b) HVD Lines Reliability

HVD Lines Reliability O&M includes the O&M expense portion of the Company's HVD pole inspections, which occur on a 12-year cycle, and MOABS tests, which occur once per year. The Company plans to spend $125,000 on HVD Lines Reliability O&M each year over the next five years.

c) LVD Substations Reliability

LVD Substations Reliability O&M maintains the safety and reliability of LVD substations, through substation and substation equipment inspections, recloser and circuit breaker test operating, and substation battery maintenance. This includes required environmental inspections under the Spill Prevention, Control and Countermeasure ("SPCC") Program. Funding for 80% of the total HVD and LVD substation mowing and weed spraying expenses is included here and consists of one weed spray per year and a five-month (May-September) mowing program with a two-times-a-month mow interval. Issues identified by inspections or patrols under this program are corrected through work orders in the LVD Substations Demand O&M sub-program, the LVD Substation Reliability capital sub-program, or the LVD Substation Demand Failures capital sub-program.

Spending in LVD Substations Reliability O&M increases over the next five years as part of the Company's plan to increase substation inspections and maintenance, as described above.

d) HVD Substations Reliability

HVD Substations Reliability O&M maintains the safety and reliability of HVD substations. This includes several activities, such as monthly substation and substation equipment inspections, breaker test operating, and substation battery maintenance. This also includes required environmental inspections due to the SPCC Program. Additionally, funding for 20% of the total HVD and LVD substation mowing and weed spraying expenses are included here. Issues identified by inspections or patrols are corrected using orders created in HVD Substations Demand O&M, the HVD Substation Reliability capital sub-program, or the HVD Lines and Subs Demand Failures sub-program.

Spending in HVD Substations Reliability O&M increases over the next five years as part of the Company's plan to increase substation inspections and maintenance, as described above.

e) HVD Lines Demand

HVD Lines Demand O&M includes certain expenses for repairs to 46 kV and 138 kV lines equipment. This also includes associated on-call costs for line crews. Activities are typically emergent and identified by failures resulting in customer outages, failures resulting in equipment outages, key calls, helicopter patrols, ground patrols, and investigation of trip and reclose occurrences.

Spending in HVD Lines Demand O&M is consistent at around $1 million per year over the next five years.

f) LVD and HVD Substations Demand

Both LVD Substations Demand O&M and HVD Substations Demand O&M respond to failures resulting in customer outages or equipment outages, poor testing results (e.g., IR inspections, oil sampling, etc.), and substation asset management database algorithms, supporting the Company's safety and reliability objectives by ensuring customer and electric system safety, outage restoration, and repairs to equipment to maintain operational functionality of the electric system.

LVD Substations Demand O&M includes expenses for emergent restoration and corrective maintenance on LVD substation equipment and facilities. This includes work on the equipment, facilities, infrastructure, and property associated with LVD substations.

HVD Substations Demand O&M includes expenses for unplanned and emergent restoration, as well as corrective maintenance on HVD and Strategic Customer substation equipment and facilities.

Spending in both LVD Substations Demand O&M and HVD Substations Demand O&M increases over the next five years as part of the Company's plan to increase substation inspections and maintenance, as described above.

g) Corrective Maintenance

Corrective Maintenance O&M supports customer and field generated orders associated with imminent safety issues or system deficiencies, including emergent and short-term planned maintenance requirements. These work orders are categorized for reporting purposes among two main activity types: investigations and maintenance. This ensures compliance with regulatory requirements and supports the Company's safety and reliability objectives through maintenance to address safety issues and system deficiencies.

Spending in Corrective Maintenance O&M is generally consistent at around $4.9 million per year over the next five years.

h) Staking

Staking O&M supplies external resources to locate and mark underground electric distribution facilities in accordance with the MISS DIG law (Public Act 174 of 2013), a key component of securing public and employee safety. Work is performed by a contractor on a multi-year contract with the Company. Work order numbers and projected expenses are based on historical numbers.

Over the next five years, the Company projects a modest increase in Staking O&M spending, based on an increase in the amount of staking orders received by the Company. Recent history has indicated an average growth rate in the number of orders of 3% per year. The Company uses these projections and the rates stipulated in the Company's contract with its staking contractor to determine projected spending in this sub-program.

i) Streetlighting

Streetlighting O&M supports the personnel and materials necessary to complete streetlight replacement maintenance activities. In recent years, the Company has capitalized more of its streetlighting work, because the Company has found that it is often more efficient to replace a component, incurring a capital cost, rather than attempt to repair it, as the repair work in this sub-program can require more people and more trips than a replacement.

Spending in Streetlighting O&M is generally consistent at around $1.8 million per year over the next five years.

j) Service Calls

The Company estimates, based on historical numbers, that employees will respond to between 19,500 and 20,000 discrete service calls during a given year. Service Calls O&M spending funds these responses.

Spending for Service Calls O&M is generally consistent at just under $5 million per year over the next five years.

k) Alma Equipment Repair

Alma Equipment Repair O&M spending includes maintenance activities (testing, repairing, reconditioning) for assets such as mobile substation equipment, substation oil processing equipment, and substation power transformer cooling equipment. The also includes activities such as substation equipment acceptance testing and ensuring compliance with all environmental regulations regarding the handling, storage, and disposal of equipment containing PCBs. These activities are considered base level maintenance for system reliability and emergency response to demand outages.

The Company has made an enhanced focus on waste elimination efforts leading to a shift in work-mix for this equipment repair from O&M to capital, with the capital spending accounted for among multiple capital spending sub-programs on a project-to-project or order-by-order basis. Additionally, a new retired equipment salvage contract has helped eliminate some labor-intensive salvage work, and the Company has been able to complete required work using less overtime than was needed in prior years. These reductions help offset the impact of inflation on Alma Equipment Repair O&M. Consequently, spending is projected to remain consistent at around $1 million per year over the next five years.

l) Tools

Tools O&M covers the purchase of smaller tools; refer to the Tools Capital sub-program for the purchase of tools costing over $1,000. Spending for Tools O&M is generally consistent, accounting for inflation, over the next five years.

m) Field Operations Expenses

This O&M covers additional miscellaneous expenses for Field Operations. This spending is generally consistent over the next five years.

ii. Metering O&M

Metering O&M includes four spending areas, each related to metering activities. The Company's five-year spending plan is as follows:

FIGURE 179

METERING O&M SPENDING

5-Year O&M Plan (all values in $ millions)					
	2021	2022	2023	2024	2025
Meter Services and Credits	4.7	4.4	3.5	3.6	3.8
Meter Reading	1.8	1.8	1.9	1.9	2.0
Meter Tech and Management System Support	1.3	1.4	1.3	1.3	1.4
Smart Energy MTC	9.6	9.7	8.7	8.8	8.9
Total	**17.3**	**17.3**	**15.3**	**15.7**	**16.0**

Spending on Metering O&M is generally consistent over the next five years.

a) Meter Services and Credits

Meter Services and Credits O&M funds Electric Meter Operations ("EMO"), whose expenses are offset by first set and retirement credits of both meters and metering transformers. EMO responds to customer-initiated and Company-generated orders for replacement or repair of existing meters. EMO also conducts handheld read routes, which are meter reads outside of the Company's regular Meter Reading Program that require special equipment.

Similar to transformers, meters are purchased through metering capital programs, discussed. In addition to the direct cost for meters, a first-set credit value is included to offset the cost of labor for installation. When meters are purchased and received, the first-set credit value for each meter is totaled at the end of each month and credited back to O&M for the installation labor. The credits are intended to entirely offset the labor costs, but due to the monthly lag discussed above, there is some net expense.

b) Meter Reading

Meter Reading O&M funds field employees reading meters. It also funds office support staff to manage scheduling and re-routing efforts to optimize efficiency in field operations.

c) Meter Technology and Management System Support

Meter Technology and Management System Support O&M funds MTC activities to support the LVD Metering New Business capital sub-program. This O&M funds the testing, refurbishing, and technology evaluation of the Company's capital program-related metering equipment. Activities include testing a sample of each shipment of new meters and metering transformers prior to release for use in the field. This O&M spending is based on investments in the capital metering sub-program.

In addition, in 2020, the Company's Smart Energy Operation Center ("SEOC") was merged in the MTC operation. Consequently, this O&M now also funds SEOC operations, including daily interrogation of smart meter data and event logs to provide customer billing data, support of demand response programs, and maintenance of the overall health of the smart meter population.

d) Smart Energy MTC

Smart Energy MTC O&M consists of three components: (i) communications backhaul for both Smart Meters and Cellular-Under-Glass legacy meters; (ii) meter software maintenance charges; and (iii) 3G to 4G meter conversion costs. The charges are fixed by a contract that establishes the charging rates through 2022. These rates are based on the number of active electric smart meters the Company has installed at customer locations, and meter inventory levels required to meet new business and meter failure requirements throughout the year. As these charges are fixed, the spending forecast is based on the projected number of meters and is adjusted annually based on projections for new business, regulatory requirements, or other large projects.

This O&M is slightly higher in 2021 and 2022 for two reasons. First, the Company has eliminated electro-mechanical meters and landline telephone lines to legacy meters being used for applications that are not compatible with smart meters; the Company has enabled these legacy meters with cellular capabilities, paying for the cellular charges through this O&M. The Company has about 5,000 such legacy meters, read via the MV90 system.

Second, the Company's cellular provider will be retiring its 3G network by the end of 2022, requiring the Company to replace 200,000 3G meters and retrofit 400,000 3G meters. While the meter manufacturer will bear most of the cost of this process, per the Company's contract, the Company will incur about $800,000 of its own costs per year.

iii. Staffing O&M

Staffing O&M includes two spending areas, which involve ensuring that the Electric Operations organization has a sufficient workforce to support the Company's distribution work plan. The Company's five-year spending plan for Staffing O&M is as follows:

FIGURE 180

STAFFING O&M SPENDING

5-Year O&M Plan (all values in $ millions)					
	2021	2022	2023	2024	2025
Training	10.2	12.6	12.7	13.1	13.5
Supervision and Administration	4.8	6.6	7.1	7.5	7.6
Total	**15.0**	**19.2**	**19.8**	**20.6**	**21.1**

Spending is expected to increase over the next five years as the Company expands its workforce to complete the increased amount of work in capital investments, particularly in the Reliability Program. The Company plans to add apprentices for the LVD lines workforce each year from 2021 through 2025, as well as adding a dedicated underground workforce across 2021 and 2022. Further, the Company plans to add apprentices for its electric field lab, substation maintenance, and substation operations workforces each year from 2021 through 2025. The Company plans to add 16 substation maintenance apprentices in 2021, and six in each subsequent year. Finally, the Company plans to add 16 substation operator apprentices in 2021, plus six in each subsequent year. The Company identified these workforce needs through its Enterprise Resource Planning ("ERP") process, discussed later in this report.

The Company is also increasing its spending on continuing education for its existing workforce and training its existing workforce on the new technology that is being installed on the system to support Grid Modernization.

a) Training

Training O&M includes skills-based training for Electric Operations employees including Electric Lines, Substation O&M, and Electric Meter. The expenses for operating the Apprenticeship Program includes the labor of those attending training, instructors, and committee members. Aside from the Apprenticeship Program, union labor associated with additional training like continuing education is included in this Training O&M category.

b) Supervision and Administration

This O&M includes the salaries and expenses of the supervision and leadership for Electric Operations, to ensure safe operation of facilities and adherence to Company policies.

iv. Planning and Scheduling O&M

Planning and Scheduling O&M includes costs associated with electric resource planning and closeout, scheduling and dispatch, and contract administration. These costs primarily comprise salaries and business expenses, including the office support functions that include closeout, work planning, contract administration, and business operations support.

These work activities include both capital and O&M for Electric Service and Distribution employees, electric underground and overhead contractors, and EMO. The program is primarily responsible for both weekly and long range planning, scheduling, and dispatching for the following activities: service calls, streetlighting, line extension, new business requests, relocations (house moves, build overs, etc.), alterations (upgrades, downgrades, generators), demolitions (lost customers), make ready, failures services, corrective maintenance, capacity, repetitive outage, cutout, pole replacement, sectionalizing, investigations, storm restoration, and EMO.

The Company's five-year spending plan for Planning and Scheduling O&M is as follows:

FIGURE 181
PLANNING AND SCHEDULING O&M SPENDING

5-Year O&M Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
Planning and Scheduling Total	**4.8**	**5.2**	**5.3**	**5.4**	**5.6**

This spending is projected to increase modestly over the next five years as the Company increases the amount of planned work being done on the distribution system, which will increase scheduling and dispatch needs. Expenses related to resource planning and closeout, and to contract administration, are projected to remain flat.

v. Smart Grid O&M

Smart Grid O&M includes two spending areas that provide IT support and automation support for the distribution system, although this does not represent all IT-related distribution expenses, as discussed in [refer to section on IT Plan.] The Company's five-year spending plan for Smart Grid O&M is as follows:

FIGURE 182
SMART GRID O&M SPENDING

5-Year O&M Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
Grid Management	5.0	5.4	5.3	5.4	5.6
Operations IT Projects	0.6	0.6	-	-	-
Total	**5.6**	**6.0**	**5.3**	**5.4**	**5.6**

Spending for Smart Grid O&M is generally consistent over the next five years, allowing for a small amount of inflation for Grid Management.

a) Grid Management

Grid Management is responsible for providing statewide 24/7 monitoring and control of the distribution system. This includes providing statewide coordination of major service restoration efforts and implementing grid automation using grid devices and advanced applications to improve system reliability, power quality, and reduce energy waste. Most Grid Management O&M expenses are for the salaries and expenses of employees operating and supporting the monitoring and control of the electric distribution system. There are also O&M expenses associated with specific investments that are made in this program to improve and streamline operations.

b) Operations IT Projects

The Company is planning spending in this area for two different projects in 2021 and 2022.

The first of these, Fleet Telematics, will allow the Company's scheduling and dispatch to monitor the location and movement of fleet vehicles, providing vehicle utilization and health statistics data. This project is intended to fully replace current fleet mobility and tracking solutions. This will cost $172,000 in 2021 and $570,000 in 2022.

The Company has also identified various emergent IT repairs that will need to be made in 2021 and plans to spend $477,000 on this.

vi. Electric Planning O&M

Electric Planning O&M includes four spending areas that cover salaries and expenses for the Company's Electric Planning organization. The Company's five-year spending plan in this area is as follows:

FIGURE 183

ELECTRIC PLANNING O&M SPENDING

5-Year O&M Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
LVD Planning	6.9	6.7	6.8	7.7	4.7
HVD Planning	3.8	4.3	4.3	4.4	4.5
System Protection	1.3	1.6	1.8	1.7	1.7
Planning Analytics	0.6	1.2	1.4	1.2	1.2
Total	**12.6**	**13.7**	**14.3**	**15.1**	**12.1**

While System Protection O&M and Planning Analytics O&M are projected to remain relatively flat over the five-year period, LVD Planning O&M and HVD Planning O&M are projected to increase due to increased headcount to support increased planned investment in the LVD and HVD systems.

HVD Planning O&M also includes funding for the Company's helicopter inspections, as discussed in [refer to HVD Demand Failures section]. Beginning in 2021, the Company is adding a second helicopter patrol of the HVD system, in addition to the single patrol that was already taking place. The second patrol is a key component of the Company's plan to reduce SAIDI through investments in HVD line rebuilds and rehabilitation. Helicopter patrols are crucial in identifying actual and imminent failures on the HVD system, and a second patrol will allow the Company to more thoroughly inspect the HVD system to ensure that all anomalies are properly identified.

vii. Electric Design O&M

Electric Design O&M includes five spending areas that cover salaries and expenses for the distribution functions of the Company's Electric Design organizations. The Company's five-year spending plan in this area is as follows:

FIGURE 184

ELECTRIC DESIGN O&M SPENDING

5-Year O&M Plan (all values in $ millions)					
	2021	2022	2023	2024	2025
DER Design	0.4	0.6	0.7	0.6	2.3
LVD Design	0.4	0.9	1.1	0.9	0.9
HVD Design	0.8	1.3	1.5	1.3	1.3
Joint Pole Rental	2.2	2.4	2.5	2.6	2.7
Standards and Document Control	0.5	0.6	0.7	0.7	0.7
Total	**4.3**	**5.8**	**6.4**	**6.1**	**7.9**

In general, the Company plans to modestly increase spending in Electric Design O&M over the next five years to increase its design capacity to meet its increased capital spending plan. DER Design O&M, which was new in 2019, will grow to enable the Company to expand its design capacity for accommodating more DERs on the system, particularly through distributed solar generation.

Joint Pole Rental O&M includes expenses associated with jointly utilizing poles with other utilities (e.g., telecommunications). Expenses include attaching electric facilities to phone company poles. Sharing poles, where possible, saves the Company money by reducing the need to solely install and maintain all Company-owned poles. Expenses are determined by contractual formulas defined by Joint Use Agreements telecommunications providers. Expenses and costs are based on the Federal Communications Commission maximum rate calculations for Incumbent Local Exchange Carrier and a contractual multiplier.

viii. Support O&M

Support O&M includes four spending areas that provide support to both the Electric Operations and Electric Engineering organizations. The Company's five-year spending plan in this area is as follows:

FIGURE 185
SUPPORT O&M SPENDING

5-Year O&M Plan *(all values in $ millions)*					
	2021	2022	2023	2024	2025
Compliance and Controls	1.6	1.8	1.8	1.8	1.9
Operations Performance	1.7	1.7	1.7	1.8	1.8
Operations Management	1.5	1.6	1.5	1.5	1.5
Customer Energy Specialists ("CES")	0.4	0.4	0.5	0.5	0.5
Total	**5.2**	**5.5**	**5.5**	**5.6**	**5.7**

Spending for Support O&M is generally consistent over the next five years, allowing for a small amount of inflation.

a) Compliance and Controls

Compliance and Control-related O&M expenses support expenses related to activities and personnel (including auditors) to maintain compliance with all required regulations.

b) Operations Performance

Operations Performance includes salaries and expenses for staff charged with reviewing quality, standardization of services, analysis of engineering systems, and cost across Operations and Engineering departments to provide better service and outcomes. These functions include providing visual management and problem-solving solutions to identify waste elimination opportunities and other efficiencies, plus general process improvement.

c) Operations Management

Operations Management includes the salaries and expenses for senior management staff, as well as chargebacks from internal departments specifically related to the operations of the electric distribution grid. This program also includes the electric portion of the reserves for incentive programs accruals, injuries and damages, and electric claims.

d) CES

These expenses include salaries and expenses for customer energy specialists. The primary purpose of this funding is to support all customer requests in the LVD Lines New Business capital sub-program.

IX. Distribution Spending Plan – Implementation Considerations

In its November 21, 2018 Order in Case No. U-20147, the MPSC directed the Company to include a "focus… on implementation considerations generally, with workforce being a component," (November 21, 2018 Order in Case No. U-20147, pg. 35) in this 2021 EDIIP. This section discusses two components of the implementation considerations for this five-year distribution plan. One focuses on how the Company ensures that it will have workforce adequacy over the next five years, while the other focuses on the Company's IT needs as they relate to supporting the Company's distribution business.

A. Workforce Adequacy

The Company's 2018 EDIIP, combined with the Company's 2018 electric rate case in Case No. U-20134, led to an increase in planned distribution spending, particularly in the Reliability capital program, starting in 2019. To accommodate and execute this increased distribution work, the Company developed a regular review process to assess the number of workhours contained in the Company's workplan and ensure that sufficient workforce resources would be available at the right times to meet demand.

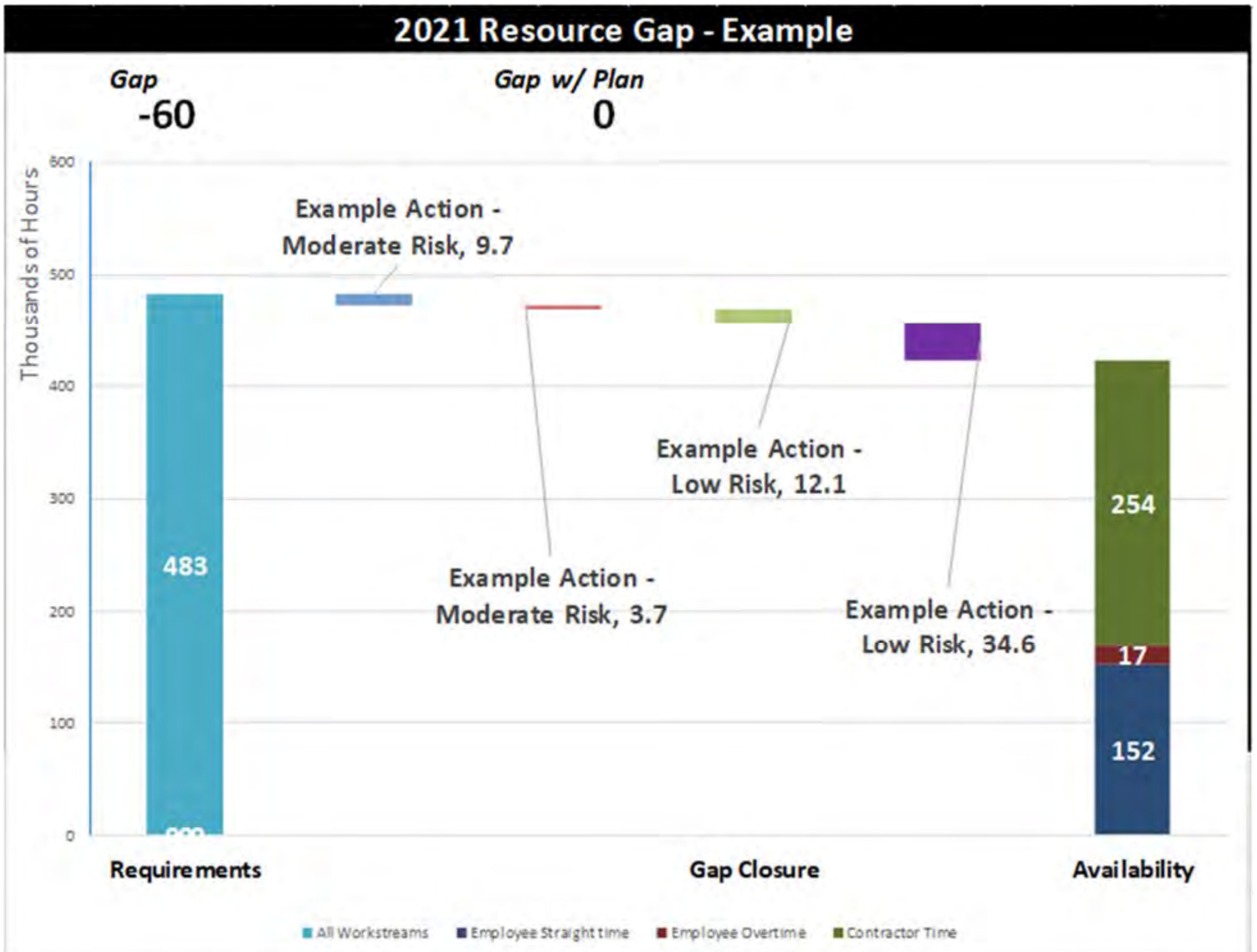
Initially, this review process focused only on ensuring the adequacy of the Company's field resources in the immediate year of 2019; since the Company began to increase planned distribution spending during that year, the Company had to look at the near-term situation first. Subsequently, the Company began to evaluate workforce adequacy in future years as well, comparing the workhours necessary to complete future spending plans against expected workforce resources in those years. By looking further into the future, the Company can both a) make sure that any increased work plans are achievable and b) plan ahead to fill any identified gaps through appropriate countermeasures, as discussed below.

While the Company's initial focus was on field resources – particularly resources for LVD work – the Company has since broadened its analysis regarding types of resources. The Company now considers resource needs for various types of Electric Operations resources, including LVD line workers, underground line workers, electric field lab employees, substation operators and substation maintenance personnel, and grid management personnel. The Company also considers resource needs for the various components of Electric Planning and Electric Design O&M outlined in the Other O&M section of this report, such as LVD and HVD Planning and LVD and HVD Design.

The Company goes through a monthly review process in which a cross-functional planning team reviews workforce needs compared to available resources for the current year for each type of workforce resource. In many cases, current year needs are broken down on a month-by-month basis to ensure that work is appropriately spread out throughout the year, and to account for the timing of when any new personnel are hired. When gaps are identified, the planning team can identify countermeasures. Countermeasures can include rescheduling work to reduce demand for labor during key periods; increasing resource availability with contractors, overtime, or hiring; and/or using problem solving and waste elimination to improve efficiency, allowing existing resources to complete more work. An illustrative example of this current year review is shown in Figure 186 below.

FIGURE 186

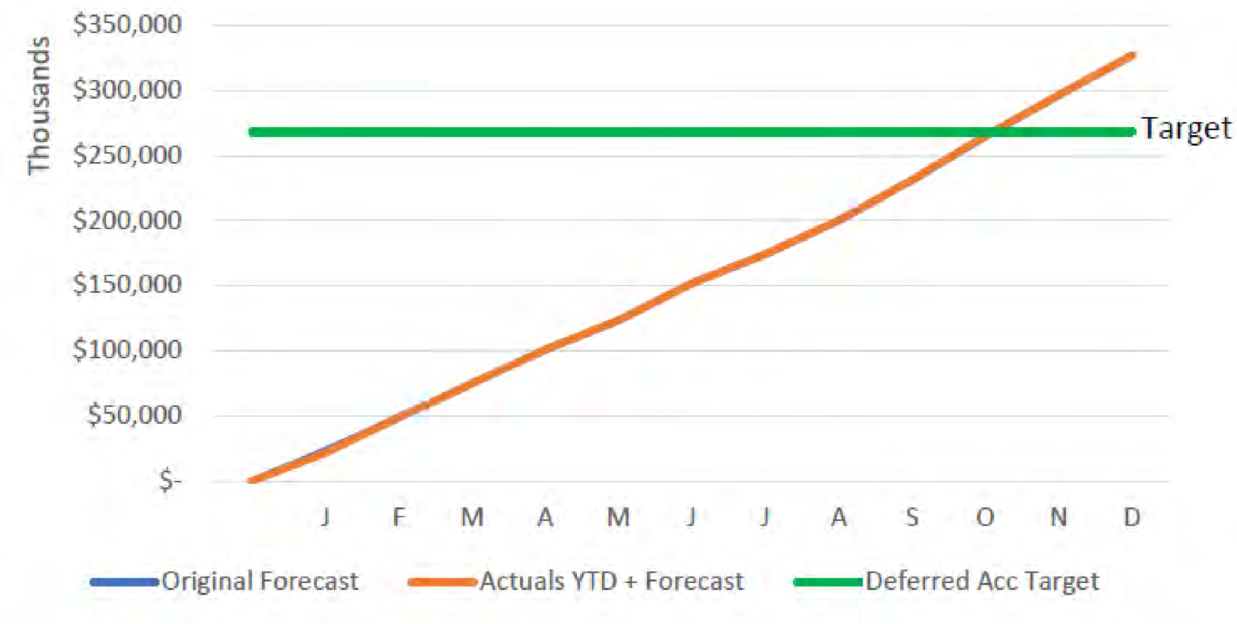
ILLUSTRATIVE EXAMPLE OF CURRENT YEAR RESOURCE GAP ANALYSIS



In 2019, the Company had a commitment to invest at least \$200 million in the Reliability program, agreed to in the settlement in Case No. U-20134. This commitment meant that the Company could not simply cut from the workplan in order to address any emergent resource gaps. By using this process of regular monthly review, the Company met that target even while dealing with emergent spending in other programs that also required resources. The Company continues to use the process of regular monthly review to ensure that it continues to meet various investment commitments, such as that to invest at least \$268 million in the Reliability program in 2021, per the MPSC Order in Case No. U-20697. Figure 187 shows how the Company tracks investment in the Reliability program against a commitment target. By including this in the monthly review process, the Company ensures that it stays on track to complete its workplan even as adjustments are made to address emergent gaps. In Figure 187, the blue “Original Forecast” line is obscured by the orange “Actuals YTD + Forecast” line, indicating that actual investment is tracking closely with the Company’s original workplan.

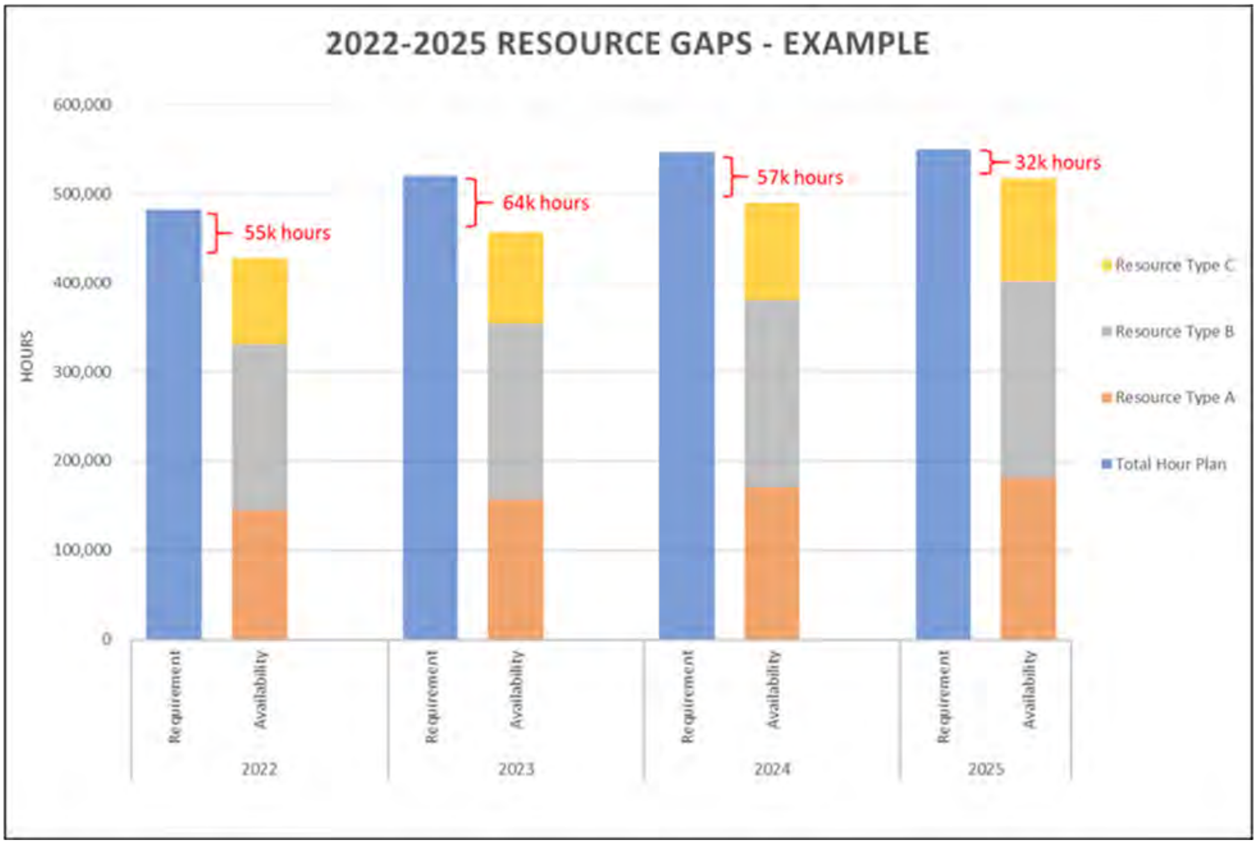
FIGURE 187

ILLUSTRATION OF RELIABILITY PROGRAM INVESTMENT MONTHLY REVIEW



While current year reviews can help address emergent resource gaps and keep the Company on track to meet annual targets, the Company also reviews projected needs and available resources over each of the next five years, so that any gaps can be identified and addressed well in advance as workplans are developed and refined. Figure 188 below provides one illustrative example of such a review.

FIGURE 188
ILLUSTRATIVE EXAMPLE OF FIVE-YEAR RESOURCE GAP ANALYSIS



By maintaining this process, the Company is confident that it will have the right workforce resources at the right times to execute on the workplan contained in this five-year spending plan.

B. Digital Plan

Beginning in 2020, the Company developed a comprehensive three-year Digital Plan to illustrate the full scope of the Company's IT capital and O&M needs to support all the Company's business areas. In addition to IT needs for supporting electric distribution, the Digital Plan also discusses IT needs related to electric generation, natural gas, and customer interfaces, plus IT support for basic corporate functions. The Digital Plan was developed with ongoing input from key Company stakeholders across business units, including in electric distribution, and has been shared with MPSC Staff at various points. The Digital Plan was filed as part of the Company's electric rate case filing in Case No. U-20963 on March 1, 2021, and the Company will update the Digital Plan on an ongoing basis and file further versions in future regulatory proceedings, ensuring that the plan stays current as IT needs evolve.

The Digital Plan identifies three key objectives necessary to support this EDIIP, as well as the Company's IRP and Natural Gas Delivery Plan ("NGDP"), which rely on foundational technologies to achieve overarching outcomes. These objectives are:

- Building new systems, enhancing existing systems, and implementing processes to enable the Company to gain knowledge of customers and energy systems. This is necessary to maneuver the delicate balance between energy demand and energy supply safely, reliably, affordably, and cleanly;
- Protecting those systems and processes, ensuring they remain secure; and
- Operating and maintaining current systems well to keep them high-performing and reliable.

Overall, the Company expects that IT-related investment and O&M to support electric distribution will increase, driven particularly by Grid Modernization spending.

i. Electric Distribution Drivers of IT Needs

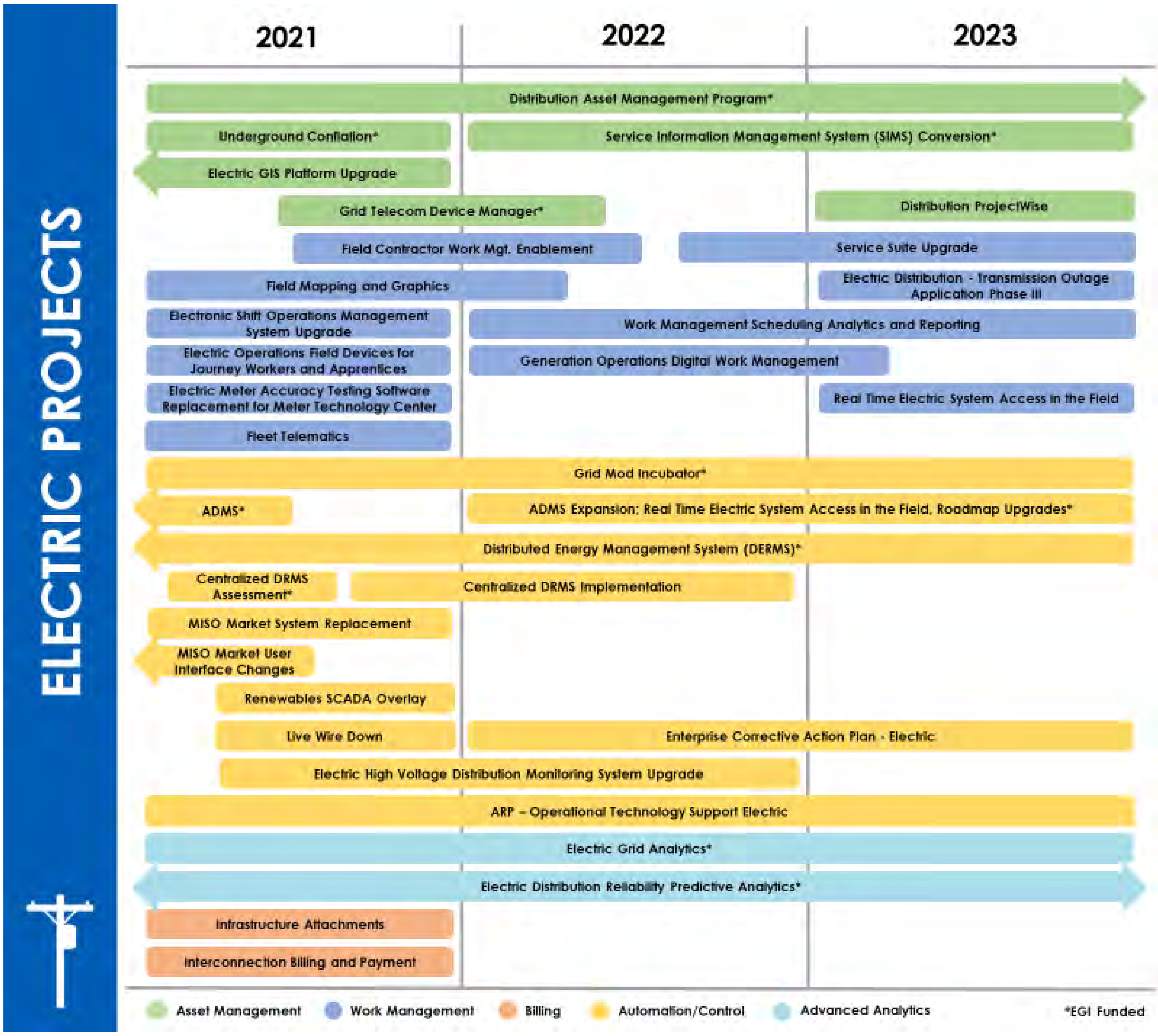
Some of the Company's IT spending is driven directly by the need for new technology to enable parts of the Company's distribution strategy. The IT Plan identifies four primary IT needs in the next three years to support the five distribution objectives established in the EDIIP:

- Expanding foundational capabilities to manage distribution assets
- Building out cyber security and data management capabilities
- Continuing to build out operational platform capabilities
- Automating interconnection billing functionality, while continuing to support and upgrade existing systems

IT needs for electric distribution are driven largely by components of the Grid Modernization Roadmap and are particularly driven by construction of the Grid Services Platform. The full scope of the Company's projected electric-related IT projects through 2023 is shown in Figure 189 below.

FIGURE 189

ELECTRIC-RELATED IT PROJECTS



Some of the projects shown in Figure 189 are funded directly by the electric distribution business and are therefore included in the Company's distribution capital investment plan, while others are funded by the Company's IT business. It is important to note that, even if a project is funded by the electric distribution business, it will create new ongoing O&M expenses for the IT business, and if this O&M is neglected the Company will not realize the full benefits of its investments, particularly those investments necessary to support the Grid Modernization Roadmap.

Because Figure 189 includes all IT projects driven by the electric business, some of the listed projects are not closely related to electric distribution. Additionally, many of the work management projects are common to the Company's electric and gas businesses.

Finally, the Digital Plan also includes IT projects necessary for management of EWR and DR programs. While these are generally discussed as customer-driven IT projects and not electric distribution-driven IT projects, EWR and DR are key components of the Company's distribution strategy (with both EWR and DR tied to an EDIIP metric), and this IT spending is therefore also critical to execution of the Company's distribution strategy.

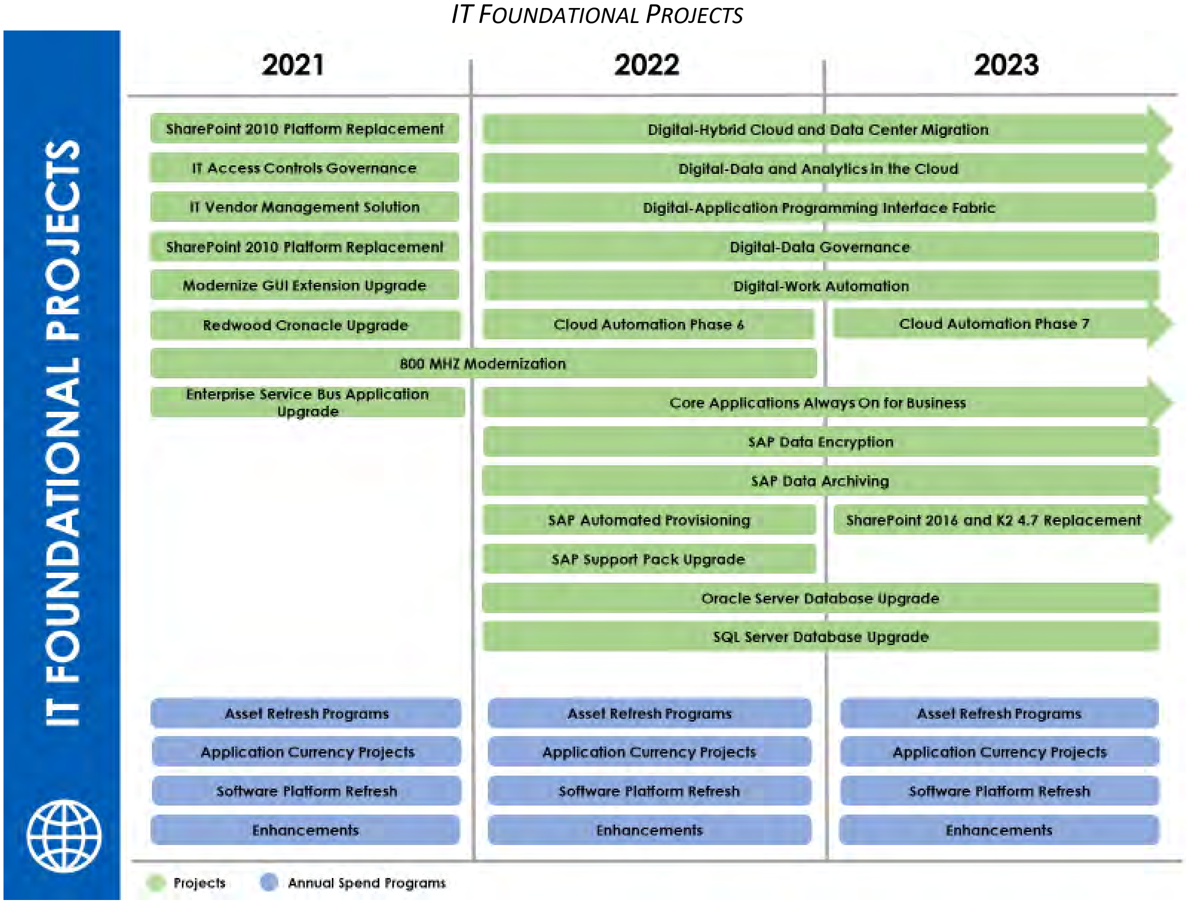
ii. Foundational IT Needs

While some IT spending is directly driven by the need for new technology to enable parts of the Company's distribution strategy, other IT spending is dedicated to technology foundational to corporate operations, without which the Company's distribution business (or, indeed, any of the Company's business areas) would not function.

The Digital Plan provides details on projects related to these foundational technologies, as shown in Figure 190 below.

FIGURE 190

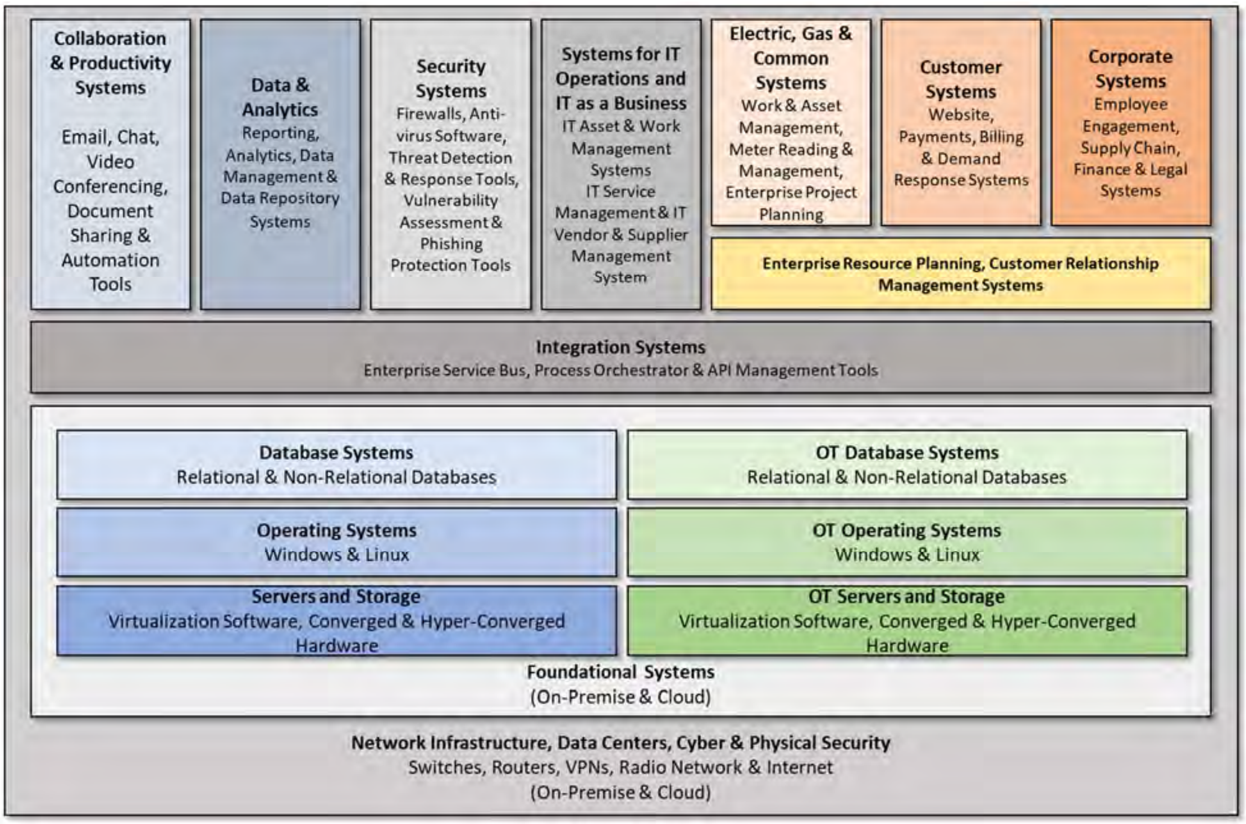
IT FOUNDATIONAL PROJECTS



Many of the IT projects shown in Figure 190 are necessary for the Company's electric distribution business to function. For example, SAP software is used, among many other things, to generate and manage orders for individual distribution projects. Database platforms, such as Structured Query Language ("SQL"), are used to manage and analyze data on distribution performance in order to target reliability improvements. Sufficient investment in foundational IT is essential for the Company's distribution business to succeed.

Both the electric-driven IT needs and the foundational IT needs form key parts of the Company's overall digital asset landscape, which the Digital Plan describes in detail and which is summarized in Figure 191 below. This digital asset landscape includes network infrastructure, data management applications, analytics capabilities, cybersecurity, and other functions necessary for the Company's electric distribution business and for other Company business areas.

FIGURE 191
DIGITAL ASSET LANDSCAPE – MAJOR COMPONENTS



X. Conclusion

This EDIIP outlines the Company's vision for the future of the electric distribution system and its plan to bring this vision to reality through investments in excelling at the basics and building for the future, through its spending plan over the next five years and through its future focused Grid Modernization Roadmap. The future of the electric distribution system is customer-driven and requires a dynamic electric distribution system integrating cleaner, more distributed sources of electric supply with grid enhancements for customers' benefit.

As the Company makes progress toward a more dynamic and integrated system, increased targeted investments will address system deterioration improving customer reliability across the grid, reinvigorating the distribution system.

This EDIIP will keep the Company on the path of achieving its five distribution objectives:

- Optimizing system cost over the long term;
- Improving reliability and resiliency;
- Enhancing cybersecurity, physical security and safety;
- Reducing waste across the system and improving sustainability; and
- Enabling greater customer control.

The Company looks forward to continued dialogue with the MPSC and the broader set of stakeholders regarding both the specifics of this EDIIP and future electric system planning efforts.

Appendix A – List of Acronyms and Abbreviations

FIGURE 192 provides a list of acronyms and abbreviations used throughout this report.

FIGURE 192

LIST OF ACRONYMS AND ABBREVIATIONS

Acronyms and Abbreviations	
Acronym	Full Text
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ATR	Automatic Transfer Recloser
BCA	Benefit-Cost Analysis
C&I	Commercial & Industrial
CAIDI	Customer Average Interruption Duration Index
CELID	Customers Experience Long Interruption Duration
CEMI	Customer Experiencing Multiple Interruptions
CHR	Criticality, Health, and Risk
CIAC	Contribution in Aid of Construction
CIP	Critical Infrastructure Protection
CNUC	CN Utility Consulting, Inc.
COVID-19	Coronavirus Disease 2019
CS	Customer-Sited
CVR	Conservation Voltage Reduction
CYME	Formerly “Chinh Yvan Micro Engineering”
DAUD	Distribution Asset Upgrade Deferral
DCC	Distribution Control Center
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation

Acronyms and Abbreviations	
Acronym	Full Text
DGA	Dissolved Gas Analysis
DMS	Distribution Management System
DR	Demand Response
DRIVE	Distribution Resource Integration and Value Estimation
DSCADA	Distribution Supervisory Control and Data Acquisition
EAB	Emerald Ash Borer
EDIIP	Electric Distribution Infrastructure Investment Plan
EM	Electromechanical
EMO	Electric Meter Operations
EPRI	Electric Power Research Institute
ESM	Energy Solutions Manager
EV	Electric Vehicle
EWR	Energy Waste Reduction
FERC	Federal Energy Regulatory Commission
FES	Future Energy System
FLISR	Fault Location, Isolation, and Service Restoration
GE	General Electric
GHG	Greenhouse Gas
GIS	Geographic Information System
GSP	Grid Services Platform
HCA	Hosting Capacity Analysis
HPS	High Pressure Sodium
HVAC	Heating, Ventilation, and Air Conditioning
HVD	High-Voltage Distribution

Acronyms and Abbreviations	
Acronym	Full Text
IEEE	Institute of Electrical and Electronics Engineers
ICE	Interruption Cost Estimate
IPLC	Impregnated Paper Lead Covered
IR	Infrared
IRP	Integrated Resource Plan
IT	Information Technology
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt-Hour
LAM	Local Affairs Manager
LCP	Load Concentration Point
LED	Light Emitting Diode
LMRs	Load Modifying Resources
LTC	Load Tap Changer
LTFP	Long-Term Financial Plan
LVD	Low-Voltage Distribution
MDOT	Michigan Department of Transportation
METC	Michigan Electric Transmission Company
MED	Major Event Day
MH	Metal Halide
MHBA	Michigan Home Builders Association
MISO	Midcontinent Independent System Operator
MMSA	Michigan Metropolitan Statistical Area

Acronyms and Abbreviations	
Acronym	Full Text
MMWG	Multiregional Model Working Group
MOABS	Motor Operated Air Break Switch
MPSC	Michigan Public Service Commission
MTC	Metering Technology Center
MV	Mercury Vapor
MW	Megawatt
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NPV	Net Present Value
NWA	Non-Wires Alternatives
NWS	Non-Wires Solutions
OMS	Outage Management System
O&M	Operations and Maintenance
PBR	Performance-Based Ratemaking
PCB	Polychlorinated Biphenyls
PV	Photovoltaic
RAE	Reliability Analytics Engine
RFP	Request for Proposals
ROW	Right of Way
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center

Acronyms and Abbreviations	
Acronym	Full Text
SEOC	Smart Energy Operations Center
SF_6	Sulphur Hexafluoride
SOAR	Streetlight Outage and Reporting
SOGS	Spring Operated Grounds Switch
SPCC	Spill Prevension, Control and Countermeasure
SQL	Structured Query Language
TOA	Transformer Oil Analysis
TOU	Time of Use
US	Utility-Scale
VCLC	Varnished Cambric Lead Covered
VoLL	Value of Lost Load
VVO	Volt-Var Optimization

Appendix B – Consumers Energy Service Center List

FIGURE 193 contains a list of service center abbreviations used in this report.

FIGURE 193

CONSUMERS ENERGY SERVICE CENTER LIST

Service Center Abbreviation List		
No.	Abbreviation	Full Name
1	ADR	Adrian
2	ALM	Alma
3	BCK	Battle Creek
4	BCY	Bay City
5	BEN	Benzonia
6	BIG	Big Rapids
7	BNC	Boyne City
8	CAD	Cadillac
9	CLD	Coldwater
10	CLR	Clare
11	GRE	East Kent / Grand Rapids East
12	FLT	Flint
13	FRE	Fremont
14	GRA	West Kent / Grand Rapids
15	GVL	Greenville
16	HML	Hamilton
17	HST	Hastings
18	JAC	Jackson
19	KAL	Kalamazoo
20	LAN	Lansing
21	LUD	Ludington
22	MDL	Midland
23	MUS	Muskegon
24	GRN	North Kent / Grand Rapids North
25	OWS	Owosso
26	SAG	Saginaw
27	SMN	South Monroe
28	TRA	Traverse City
29	TWS	Tawas
30	WBR	West Branch

Appendix C – Grid Archetype Details and Supporting Figures

FIGURE 194

CIRCUIT CHARACTERISTICS FOR ARCHETYPE CLASSIFICATION

Integrated Archetype Statistics	#1	#2	#3	#4	#5	#6	#7
# of LVD Circuits	422	225	260	478	337	258	186
# of HVD Groups	17	4	1	5	5	5	1
LVD Circuit Customers	11,569	154,930	172,466	699,631	268,559	197,962	241,909
% Residential	*41%*	*80%*	*87%*	*92%*	*88%*	*89%*	*89%*
% C&I	*59%*	*20%*	*13%*	*8%*	*12%*	*11%*	*11%*
Downstream LVD Customers *(HVD Groups Only)*	246	5,872	2,535	17,589	10,079	7,447	8,079
(Excludes ~300,000 customers served directly off 138kV Lines/Subs)							
Total Line Miles (LVD and HVD)	514	3,321	2,520	11,061	13,919	12,007	12,347
% Undergrounded (LVD Line Miles Only)	*57%*	*26%*	*33%*	*31%*	*9%*	*8%*	*12%*
% Unshielded or Non-Standard Conductor (HVD Line Miles Only)	-	-	-	-	-	-	-
Number of Radial 46kV Groups	0	1	0	1	1	0	0
Average Drive Time From Circuit to HQ (Mins)	16mins	21mins	12mins	14mins	25mins	26mins	39mins
Archetype Residential NPS *(CMS Nov. Survey)*	-	37%	44%	44%	39%	38%	36%
C&I NPS *(JDP & CMS Business Survey; Average of Circuit NPS)*	29%	26%	-	-	-	-	-
Reliability *(Excluding MED; 2013-2017 Average)*							
Archetype Average Circuit SAIFI (2013-2017, excluding MED)	0.25	0.95	0.45	0.71	0.87	1.55	1.75
Archetype Average Circuit SAIDI (2013-2017, excluding MED)	43	171	72	126	165	331	399
Archetype SAIDI Contribution (LVD excludes HVD SAIDI)	0	14	6	43	21	31	45
Archetype SAIFI Contribution (LVD excludes HVD SAIFI)	0.00	0.08	0.03	0.24	0.11	0.14	0.20
Archetype Median CAIDI (LVD only)	73	172	158	166	185	200	226

FIGURE 195

CALCULATIONS OF LVD ARCHETYPE ENVELOPE GUARDRAILS – ILLUSTRATIVE EXAMPLE

LVD Planned Capital Projects (Excludes forestry)
All spend values are loaded

Year	Illustrative
Total LVD Budget Allocation	$225M
Envelope Percent Change	20%

		LVD						
Archetype Metrics	**TOTAL**	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**
# of Circuits (LVD)	***2,163***	*422*	*224*	*260*	*476*	*337*	*258*	*186*
Spend/ Circuit (LVD)	**$104,022**	$43.9M	$23.3M	$27.0M	$49.5M	$35.1M	$26.8M	$19.3M
# of Customers (LVD Circuits)	**1,782,404**	*15,334*	*157,564*	*178,952*	*712,991*	*274,157*	*201,343*	*242,063*
Spend/ Customer (LVD)	**$126**	$1.9M	$19.9M	$22.6M	$90.0M	$34.6M	$25.4M	$30.6M
Total Line Miles (LVD)	**58,190**	*528*	*3,245*	*2,666*	*11,221*	*14,775*	*12,749*	*13,006*
Spend/ Line Mile (LVD)	**$3,867**	$2.0M	$12.5M	$10.3M	$43.4M	$57.1M	$49.3M	$50.3M
Yearly SAIDI Contribution (Excl. MED; Excluding HVD, '15-19)	***153***	*0.72*	*12.29*	*6.79*	*38.23*	*23.65*	*27.00*	*44.67*
Spend/ Minute of SAIDI Contribution	**$1,467,333**	$1.1M	$18.0M	$10.0M	$56.1M	$34.7M	$39.6M	$65.5M
Yearly SAIFI Contribution (Excl. MED; Excluding HVD, '15-19)	**0.76**	*0.00*	*0.07*	*0.04*	*0.22*	*0.12*	*0.13*	*0.19*
Spend/ Frequency Contribution	**$294M**	$1.1M	$19.5M	$11.1M	$63.7M	$34.4M	$38.6M	$56.6M
Guardrail Analysis								
Median Allocated Spend per Archetype	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
Median spend as a % of Total	***100%***	*0.9%*	*9.2%*	*5.3%*	*26.4%*	*16.3%*	*18.2%*	*23.7%*
Low Budget Spend Envelope (-20%)	**$180M**	$1.6M	$16.6M	$9.5M	$47.6M	$29.4M	$32.7M	$42.6M
Medium Budget Spend Envelope (Base)	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
High Budget Spend Envelope (+20%)	**$270M**	$2.5M	$24.8M	$14.2M	$71.3M	$44.1M	$49.1M	$64.0M

FIGURE 196

MONITORED CIRCUIT CHARACTERISTICS AND PRIORITY THRESHOLDS

	Threshold	Variable
Safety	≥2 / year	Car pole accidents/year (incl. MED); Tracking started 2016
	Ungrounded	Circuit primary voltage
	≥12 total	Total number of wiredown events requiring 911 on-scene (13-17, incl. MED)
	≥8 total	Total number of wiredown events requiring 911 on-scene (13-17, incl. MED)
	≥100	Customers/line mile
Reliability	≥0.001	Avg system SAIFI contribution (13-17, excl. MED)
	System: ≥46%	Avg percent of customers/year with ≥3 outages (13-17, incl. MED)
	Arch. 1: 10%	
	Arch. 2: 25%	
	System: ≥60%	Avg percent of customers/year with 1+ >5hr outages (13-17, incl. MED)
	Arch. 1: 21%	
	Arch. 2: 30%	
	≥18	Worst zone score (March 2018 version)
	=17	
	<0%	Residential net promoter score (NPS, 2017 panel survey)[1]
	N≥6	Number of respondents (NPS question, 2017 panel survey)[1]
	≥350 mins	Avg circuit CAIDI (13-17, excl. MED)
	≥1	Number of overloaded pieces of equipment (2017 data)[1,3]
Cost	≥$400/inc	Average O&M restoration cost per incident (15-17 data, incl. MED)[1]
	≥30%	Percent of non-MED incidents >5hrs (13-17)
	≥85	Total line miles
	≥50%	Percent of line miles underground
	≥40 mins	Average drive-time to service center / headquarters
	≥30%	Percent of non-MED incidents >5hrs (13-17)
Sust.	≤50%	Load factor coincident with 10 system peak hours (2017 data)[1]
	≥$40K cost	Replacement cost of equipment almost overloaded (2017 data)[1,2]
Control	≤50%	Load factor coincident with 10 system peak hours (2017 data)[1]
	≥$40K cost	Equipment almost overloaded replacement cost (2017 data)[1,2]
	=0%	Percent of control question responses ranked ≥9/10 (2017 panel survey)[1]
	N≥3	Number of respondents (Control question, 2017 panel survey)[1]

FIGURE 197

Solution Grid - Mapping Solutions

		Safety & Security			Reliability			System Cost			Sustainability & Control		Control
	Performance Concern	Safety risk - ungrounded circuits	Safety risk - wiredowns	Public safety risk - car pole accidents	High outage frequency	Long outage duration	Overloaded equipment (capacity)	Difficulty locating faults	Difficultly restoring faults - general	Difficultly restoring faults - underground	Opportunity to defer capacity investment	Inefficient capacity utilization - low load factor	Low customer control satisfaction
	Indicator(s)	Ungrounded circuits	High wiredown frequency	High car pole accident frequency	SAIDI, outage frequency metrics, high zone scores	Outage duration metrics (CAIDI, % of custs with 1+ 5hr outage)	Overloaded equipment replacement cost	High circuit length	High historic cost, long drive times, % of custs. with 1+ 5hr outage	High percent of line-miles underground	High value of equipment near overload	Low load factor	Scores on control surveys
	Metrics	• Recordable incident rate	• Wiredown relief factor	• N/A (general safety)	• SAIDI • SAIFI • % of custs with ≥3 outages	• SAIDI • % of custs with 1+ 5hr outage • % of MED incidents longer than 24 hrs	• Equipment Overload % • Protective Device Reach • Protective Device Coordination	• O&M $/incident	• O&M $/incident	• O&M $/incident	• Energy savings through EE • Enrollment in PPS • % system loss • System load factor	• Enrollment in PPS • % system loss • System load factor	• % of custs ranking 9/10 on CE's efforts to control energy use
	Solution Options												
Traditional Solutions	1 Line and pole work (e.g., pole replacement, poletop/line rehab, lightning arrestors)		Yes		Yes								
Traditional Solutions	2 New sectionalizing (e.g., fuses / cut-outs)				Yes		Yes	Yes					
Traditional Solutions	3 Equipment replacement (e.g., fuses, reclosers, regs, transformers)				Yes		Yes						
Traditional Solutions	4 Equipment upgrades (e.g., reconductoring, capacity for transformers, lines, line equipment)						Yes				Yes		
Traditional Solutions	5 Car pole accident guards (e.g., attenuators, flashings, posts, raptor block)			Yes	Yes	Yes							
Traditional Solutions	6 Underground cable work (e.g., replacement, cable injection, fault indicator, metro work)				Yes	Yes			Yes	Yes			
Traditional Solutions	7 Line clearing / tree trimming		Yes		Yes								
Traditional Solutions	8 Circuit exit switch	Yes											
Reconfiguration Solutions	1 Line relocation (e.g., off swampy land, customer property)		Yes	Yes	Yes	Yes							
Reconfiguration Solutions	2 Circuit reconfiguration (e.g., new substation, new transformer bank to split circuit)				Yes		Yes	Yes			Yes		
Reconfiguration Solutions	3 Line reconfiguration (e.g., undergrounding, tree wire, aerial spacer cables, vertical construction)		Yes	Yes	Yes	Yes							
Reconfiguration Solutions	4 Underground loops					Yes	Yes			Yes	Yes		
Reconfiguration Solutions	5 Mobile equipment (e.g., mobile substations, mobile isolators)					Yes			Yes				
Reconfiguration Solutions	6 Phase balancing and load transfers					Yes	Yes				Yes		
Reconfiguration Solutions	7 Reinforce / create ties to other circuits					Yes			Yes	Yes			
Reconfiguration Solutions	8 Non-standard / ungrounded voltage upgrade	Yes			Yes								
Grid Modernization Solutions	1 Distribution supervisory control and data acquisition at the substation (DSCADA)		Special cases	Special cases	Yes	Yes		Special cases	Special cases		Yes	Yes	Yes
Grid Modernization Solutions	2 Distribution automation loops (DA loops)				Yes	Yes							
Grid Modernization Solutions	3 Line Sensors				Yes	Yes		Yes	Yes		Special cases	Yes	
Grid Modernization Solutions	4 Regulator controller upgrade to enable conservation voltage reduction (CVR)						Yes				Yes	Yes	

Solution Grid - Mapping Solutions

			Safety & Security			Reliability			System Cost			Sustainability & Control		Control
		Performance Concern	**Safety risk - ungrounded circuits**	**Safety risk - wiredowns**	**Public safety risk - car pole accidents**	**High outage frequency**	**Long outage duration**	**Overloaded equipment (capacity)**	**Difficulty locating faults**	**Difficultly restoring faults - general**	**Difficultly restoring faults - underground**	**Opportunity to defer capacity investment**	**Inefficient capacity utilization - low load factor**	**Low customer control satisfaction**
		Indicator(s)	Ungrounded circuits	High wiredown frequency	High car pole accident frequency	SAIDI, outage frequency metrics, high zone scores	Outage duration metrics (CAIDI, % of custs with 1+ 5hr outage)	Overloaded equipment replacement cost	High circuit length	High historic cost, long drive times, % of custs. with 1+ 5hr outage	High percent of line-miles underground	High value of equipment near overload	Low load factor	Scores on control surveys
		Metrics	• Recordable incident rate	• Wiredown relief factor	• N/A (general safety)	• SAIDI • SAIFI • % of custs with ≥3 outages	• SAIDI • % of custs with 1+ 5hr outage • % of MED incidents longer than 24 hrs	• Equipment Overload % • Protective Device Reach • Protective Device Coordination	• O&M $/incident	• O&M $/incident	• O&M $/incident	• Energy savings through EE • Enrollment in PPS • % system loss • System load factor	• Enrollment in PPS • % system loss • System load factor	• % of custs ranking 9/10 on CE's efforts to control energy use
		Solution Options												
New Tech Solutions	1	Battery storage and smart inverter				Look for multiple	Look for multiple	Look for multiple	Look for multiple	Look for multiple		Look for multiple	Look for multiple	
New Tech Solutions	2	Distributed generation						Yes				Yes	Yes	Yes
New Tech Solutions	3	Smart electric vehicle (EV) charger (e.g., shift charging to off-peak, use as DR resource)						Yes				Yes	Yes	Yes
New Tech Solutions	4	Enable two-way power flow to facilitate solar installations						Yes				Yes		Yes
Customer Solutions	1	Targeted enrollment in Energy Efficiency program						Special Cases				Yes		Yes
Customer Solutions	2	Targeted enrollment in Peak Power Saver (Residential only)						Special Cases				Yes	Yes	Yes
Customer Solutions	3	Targeted Demand Response (Commercial and Industrial customers)						Special Cases				Yes	Yes	Yes
Customer Solutions	4	Community solution (e.g., engagement, education, other)		Yes	Yes	Yes	Yes	Special Cases				Special cases		Yes
Customer Solutions	5	Customer programs (e.g., alternative rates, performance based rates, billing, other)				Yes	Yes						Yes	Yes
Operational Solutions	1	Add new headquarters or material storage areas (buy or lease)					Yes			Yes				
Operational Solutions	2	Hire additional crewpeople / contractors (Consider contracts; may be limited by availability of labor)					Yes			Yes				
Operational Solutions	3	New equipment or tools (e.g., Underground cable carts, drones, app/field maps, diggers)				Yes	Yes		Yes	Yes	Yes			
Operational Solutions	4	Assessments (target assessments out of typical cycle, for areas considered higher risk)		Yes	Yes	Yes				Yes				

Appendix D – Concept Approval Examples

Example 1: LVD Lines Reliability

Notification Concept Number: 1048914420

Project Title: RLBY HARRIETTA-BOON LCP 717 **Work HQ:** Cadillac

Date: December 23, 2019 **Proposed Year of System Changes:** 2021

Problem Description:

The zone downstream of LCP 717 on Harrietta Substation, Boon Circuit, has seen multiple outages in the last 12 months. A five mile portion of this zone runs through multiple areas with hardwood trees surrounding both sides, increasing the chances for tree-caused outages. There are 490 customers served by this zone, which has had nine outages over the past three years all due to trees or weather.

Alternative Solutions:

1. Relocate 0.5 miles of #4 ACSR conductor using 1/0 ACSR conductor along S 5 Rd and W 34 Rd, and the area along W 34 ½ Rd and M-37 (S Grandview Hwy). Then, reconductor approximately 1.5 miles of #2 and #4 ACSR conductor with 336.4kcmil standard construction starting at address 6581 S 1 ½ Rd continuing south to 11252 W M-55 Hwy. Complete standard forestry clearing for this line section. Relocate all lateral fusing to the location of the main three phase line ensuring all laterals are fused to improve system protection. Ensure standard lightning protection in the zone of protection of LCP 084 (i.e. every 1300' for the three phase line). Estimated annual customer•outage•minutes saved is 928,260.

Estimated Design Hours = 1015

Estimated Loaded Cost = $658,000

2. Relocate 0.5 miles of #4 ACSR conductor using 1/0 ACSR conductor along S 5 Rd and W 34 Rd, and the area along W 34 ½ Rd and M-37 (S Grandview Hwy). Then reconductor approximately 1.5 miles of #2 and #4 ACSR conductor with 336.4kcmil Tree Wire construction starting at address 6581 S 1 ½ Rd continuing south to 11252 W M-55 Hwy. Complete standard forestry clearing for this line section. Relocate all lateral fusing to the location of the main three phase line ensuring all laterals are fused to improve system protection. Ensure standard lightning protection in the zone of protection of LCP 084 (i.e. every 1300' for the three phase line). Estimated annual customer•outage•minutes saved is 1,031,400.

Estimated Design Hours = 1062

Estimated Loaded Cost = $688,824

Consumers Energy
LVD Planning
CONCEPT APPROVAL

Recommended Alternative:

Alternative # 1 is recommended to strengthen the distribution line and reduce outage duration caused by trees falling from outside of the standard tree clearing zone. The standard construction is lower cost and is based on input from Consumers Energy Line Crews on the difficulties of restoring damage to alternative construction methods. Alternative # 2 is similar but utilizes tree wire to reduce the total number of outages seen by customers in the zone from trees outside the ROW, but it may increase outage duration if the tree wire section is damaged by trees exceeding the capabilities of the shield wire.

Conceptual Estimate:

Program	Notification #	Loaded Cost	Description
LVD Reliability	1048914420	$658,000	Reconductor and/or relocate 2 miles of distribution line
Project Total		$658,000	

Present Need: On approval, this document authorizes the Low Voltage Distribution Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Circuit Owner: Michael Korpi **System Engineer:** JPBrack

Approvals:

Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	N/A

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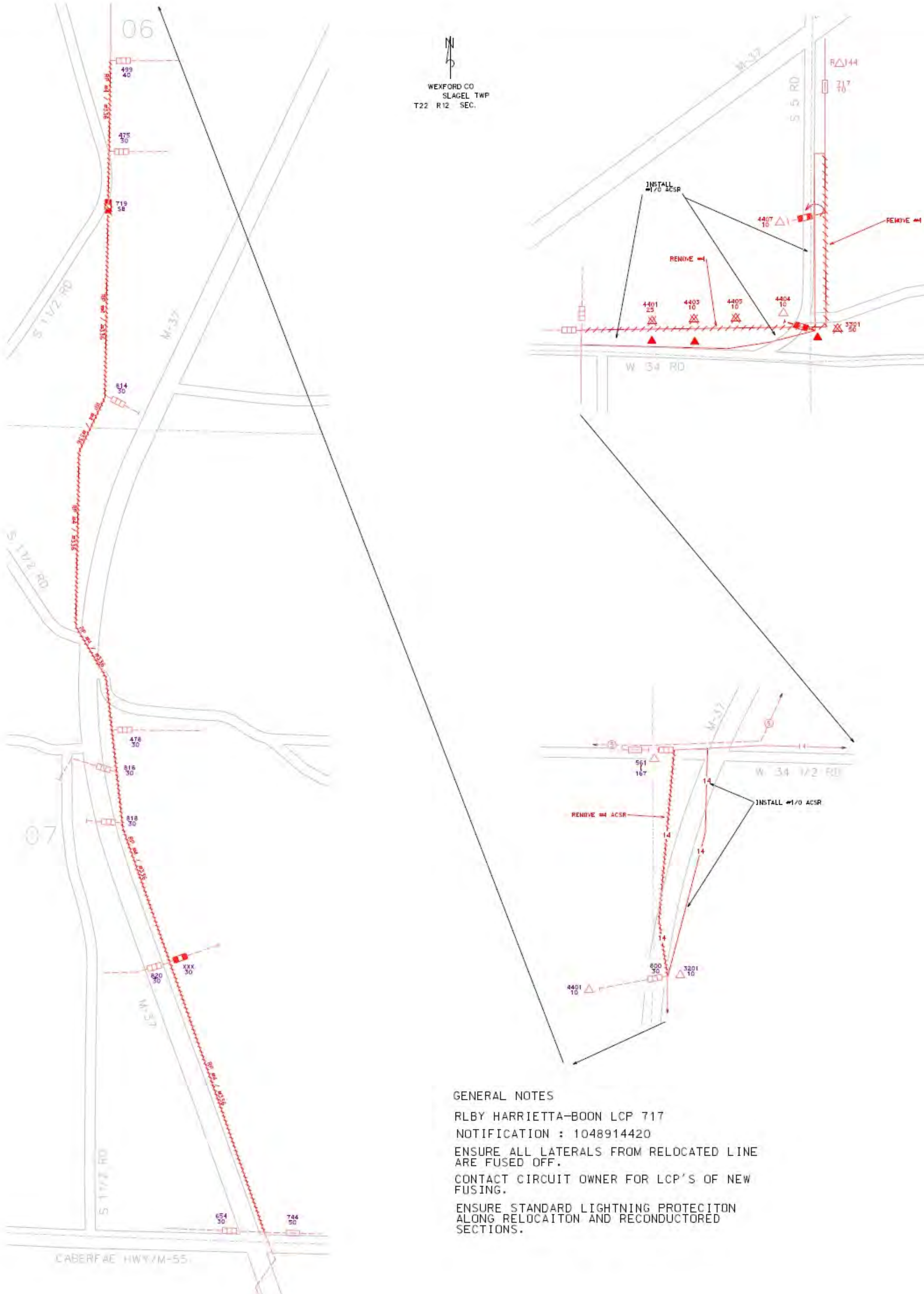
Scope Map:



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Existing Location of Facilities:

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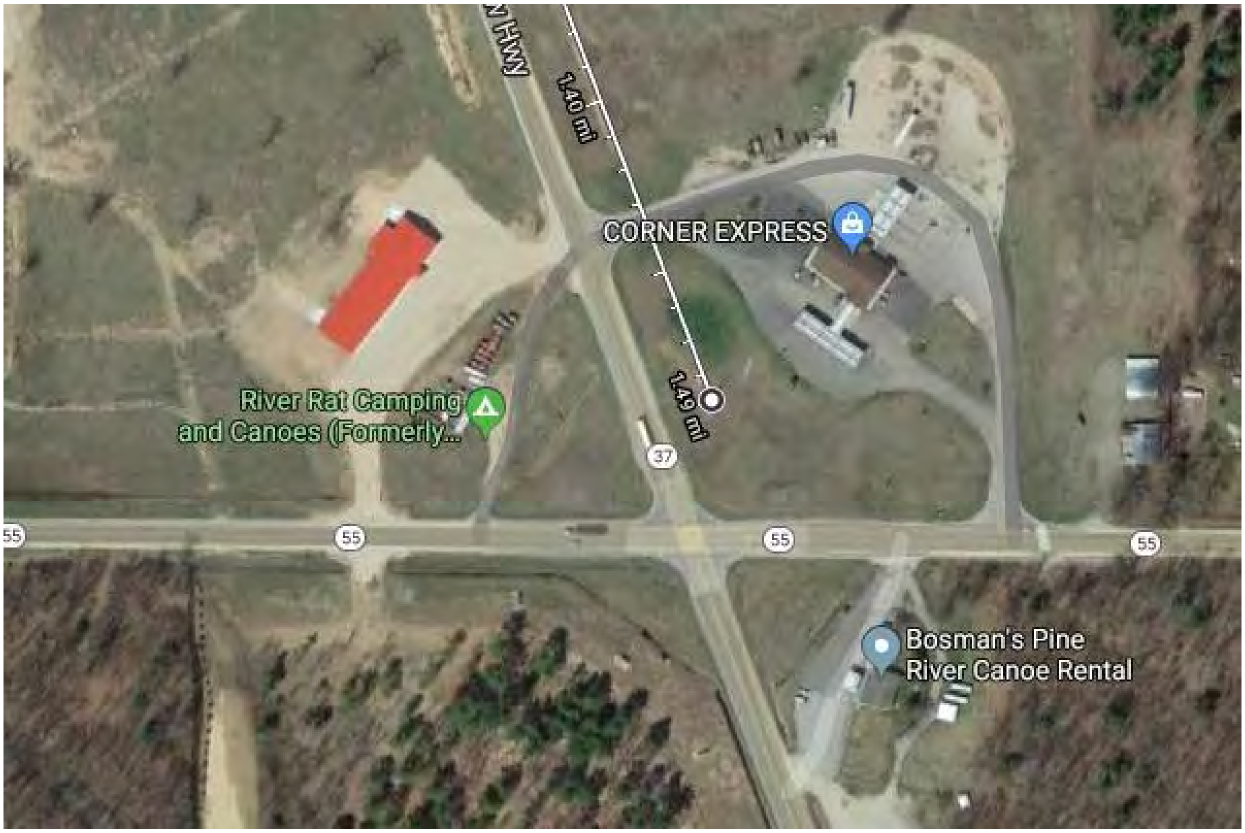


From:	SPAdvisor
To:	Joshua L. Birchmeier
Subject:	Approval has completed on RLBY HARRIETTA-BOON LCP 717.
Date:	Sunday, December 22, 2019 11:31:59 AM

Approval has completed on RLBY HARRIETTA-BOON LCP 717.

Approval on RLBY HARRIETTA-BOON LCP 717 has successfully completed. All participants have completed their tasks.

Approval started by Joshua L. Birchmeier on 11/13/2019 4:30 PM Comment:
Please review and approve/reject the proposed LVD concept.

Approved by JOHN P. BRACK on 11/14/2019 11:02 AM Comment:
Approved

Approved by JULIA R. FOX on 11/15/2019 1:56 PM Comment:

Approved by DONALD A. LYND on 12/19/2019 11:39 AM
Comment: Approved.

Approved by RICHARD T. BLUMENSTOCK on 12/20/2019 2:22 PM
Comment: Approved.

Approved by Timothy J. Sparks on 12/22/2019 11:31 AM
Comment: Approved.

View the workflow history.

Example 2: HVD Lines Reliability

Consumers Energy
Customer & Service Infrastructure
CONCEPT APPROVAL

Concept Number: 17-0019A

Project: Rosebush Line – Rebuild line in new location Rev A **County**: Isabella

Date: February 6, 2018 **Need System Changes By:** 4/1/2021

Problem Description:

The Rosebush 46 kV line, LN033F, connecting Summerton and Warren substations, is 13 miles long and in a condition of deterioration. Consumers' existing property rights along the line, based on a previous court case, are not sufficient to reconstruct the line along the same route. Some parts of the line are difficult to access, hindering line maintenance. Along portions of the line tree clearing rights are only 17.5' from centerline, whereas the norm for a 46 kV line is 40'. Thus, the line has an increased danger of failure resulting from a falling tree or branch. An HVD lines reliability project to rebuild the line is approved through the economic model at this time, but rebuilding along the same route is not recommended due to the property issues already mentioned nor is it conducive to future plans for the area.

The Frost 46 kV line has been shown in planning and operations studies to have low voltages in the event of an outage to the 46 kV bus at Bard Rd. substation. In such cases the customer-owned Larch generating station is relied upon to maintain acceptable voltage levels. The Frost 46 kV line connects Bard Rd. and Warren substations and is 36 miles long (with 52 miles of total exposure). The Vernon 138 kV/46 kV substation presently feeds only the radial Surrey line. Vernon is located near the Frost 46 kV line route and was constructed with the intent of looping into the Frost 46 kV line to alleviate this problem.

Alternative Solutions:

Alternative #1 (Recommended)

Reconstruct the Rosebush 46 kV line along a new 14 mile route, starting from existing structure #214 or #215 to a new line exit at Vernon substation. A new ¼ mile tap off of the line would be constructed to feed Rosebush substation. Loop Vernon substation into the Frost 46 kV line by creating two new lines and line exits to tap the Frost line, then open the Frost line between the two taps. Looping Vernon into the Frost line will provide better voltage support to the northern Frost line than Warren substation does as well as improve reliability and reduce line losses. Operationally, to maintain the present level of system flexibility, looping Vernon into the Frost line will be necessary in order to replace the 46 kV source into Warren substation that would be eliminated by the removal of the existing Rosebush line.

This project would proceed in three phases:

1) Acquire property rights and construct 5.5 miles of new 46 kV line from structure #214/215 north approximately to E. Rosebush Rd. Construct a new ¼ mile tap from Mission Rd. east to Rosebush substation. Install a 46 kV switch on the 5.5 mile line segment south of the ¼ mile tap. Upon completion of this phase the old Rosebush line can be operated normally open and Rosebush substation can be normally fed from the new line.
2) Expand Vernon substation to add four circuit breakers, making one a sparing breaker, and three new 46 kV line exits. Move the existing Surrey line exit from the existing 166 breaker to a new breaker. Construct new 46 kV line taps from the new line exits to tap the Frost line north of the 188 switch and the Surrey line west of the 488 switch; then make the Frost 188 switch normally open and the Surrey 488 switch normally closed. The fourth breaker will be designated for the new Rosebush line to be constructed as phase 3.
3) From the new ¼ mile Rosebush tap construct a new 8 mile 46 kV line to Vernon substation. Install a new 46 kV switch to the north of the new Rosebush tap. Upon completion, the new Rosebush line can be operated as a looped line between Summerton and Vernon and the old Rosebush line can be retired.

The three project phases can be executed in parallel, wherever possible. However, phase 1 is needed to feed Rosebush substation ASAP, in case of a failure of the existing Rosebush line. The conceptual cost for this project is $8,803,000.

Rev A: After detailed Engineering and Field reviews of the project, it was determined that the R/W cost estimates and lead times originally quoted in this concept were incorrect due to increased number of parcels required for construction. The details of the increased costs can be found in the table below. The new conceptual cost for this project is $9,746,000

Project Phase	**Original Estimate**	**New Estimate**	**Reason for increased costs**
Phase I (5.7 miles from Weidman Jct to Rosebush)	$480,000	$843,000	Increased number of parcels
Phase 2 (1.3 miles for taps to Vernon)	$146,000	$326,000	Route travels through city/industrial areas
Phase 3 (8 miles from Vernon to Rosebush)	$641,000	$1,041,000	Increased number of parcels
Total	**$1,267,000**	**$2,210,000**	

Alternative #2

Rebuild the Rosebush 46 kV line on the existing route and centerline. Acquire additional easements where existing property rights are inadequate. If the standard HVD right of way were attainable the loaded cost estimate for construction and right of way would be $4,722,000. However, after much prior effort on the part of CE’s Real Estate Acquisition department, the proper easements for this construction project are regarded as unattainable. In addition, the project to loop Vernon substation into the Frost 46 kV line would still be scheduled separately, at a cost of $2,415,000 loaded, totaling $7,415,000 for the two projects. Furthermore, Rosebush substation would remain served by a 3.3 mile radial spur. While alternative #2 is lower in cost than alternative #1 it is not a viable alternative because the Rosebush line cannot be rebuilt on the same centerline.

Recommended Alternative:

Alternative #1 is recommended – This is the best viable alternative. This alternative is preferred by the HVD Lines Construction, Real Estate Acquisition, Forestry, Operations, and HVD Planning departments. Overall, there would be approximately 12 miles less total line exposure than for alternative #2 and annual customer-minute savings (121,000 customer-minutes) and line loss savings ($31,000) as compared to the present system configuration. Relocating the Rosebush 46 kV line along the US-127 corridor will facilitate system expansions necessary to serve future load growth in the area and would be more easily accessible for construction and maintenance.

METC facilities are not required for this project.

Conceptual Estimate by WBS:

WBS Element	2018 Direct Cost	2018 Cost with Overheads	Description
EH-95208	$806,000 $684,000	$843,000 $716,000	Acquire R/W for 5.7 miles 46 kV from Weidman Jct to Rosebush. Acquire R/W for 8 miles 46 kV from Rosebush to Vernon (part 1)
WBS Element	**2019 Direct Cost**	**2019 Cost with Overheads**	**Description**
EH-95208	$314,000 $312,000	$326,000 $325,000	Acquire R/W for 1.3 miles 46 kV from Vernon substation Acquire R/W for 8 miles 46 kV from Rosebush to Vernon (part 2)
EH-95308	$1,509,000	$2,265,000	Construct 5.7 miles new 46 kV line from near Weidman Jct to Rosebush + 1 46 kV ABS.
WBS Element	**2020 Direct Cost**	**2020 Cost with Overheads**	**Description**
EH-95008	$1,204,000 $321,000	$1,792,000 $477,000	Expand Vernon substation to add 4 breakers and 46 kV line exits. Construct two 46 kV taps from Vernon to Frost & Surrey lines totaling 1.3 miles.
EH-95308	$1,505,000	$2,253,000	Construct 8 miles new 46 kV line from Rosebush to Vernon + 1 46 kV ABS (part 1)
WBS Element	**2021 Direct Cost**	**2021 Cost with Overheads**	**Description**
EH-95308	$500,000	$749,000	Construct 8 miles new 46 kV line from Rosebush to Vernon + 1 46 kV ABS (part 2)
Project Total	$7,155,000	$9,746,000	

Present Need: On approval, this document authorizes the High Voltage Distribution Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: ~~BDStyes~~ JRMcCormick **Team Leader:** ALRoot

Approvals:

Director, Customer & Service Infrastructure HVD	Dwayne C. Parker	Required
Director, Elec Transmission & HVD Eng	James R. Anderson	Required
Vice President, Electric Grid Integration	Timothy J Sparks	Required
Senior Vice President, Transformation/Eng & Ops Sprt	Jean-Francois Brossoit	Required
President	Patricia K. Poppe	Required

From:	Electric Asset Management
To:	SUSAN L. WATTERS
Cc:	SUSAN L. WATTERS; CINDY L. KEZELE; Brian M. Bushey; DONALD A. LYND; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews
Subject:	Approval has completed on 17-0019A Rosebush_Line-Rebuild_Line_in_New_Location - Rev.A.
Date:	Tuesday, February 27, 2018 6:40:54 PM

Approval has completed on 17-0019A Rosebush_Line-Rebuild_Line_in_New_Location - Rev.A.

Approval on 17-0019A Rosebush_Line-Rebuild_Line_in_New_Location - Rev.A has successfully completed. All participants have completed their tasks.

Approval started by SUSAN L. WATTERS on 2/6/2018 3:55 PM

Comment: A new document has been added to the C&SI HVD Project Collection under the approval limit of

$5,000,000. Please view the document and approve or comment.

Approved by ARIC L. ROOT on 2/8/2018 9:29 AM
Comment:

Approved by DWAYNE C. PARKER on 2/21/2018 3:41 PM
Comment:

Approved by James R. Anderson on 2/21/2018 8:39 PM

Comment: I approve. An ~ $940k increase in the project cost associated with real estate costs being higher than what was originally projected, moving the project cost from ~ $8.8M to ~ $9.7M. Does not change the selected alternative. Original and revised cost required approvals through and including Patti. Thx. JRAnderson

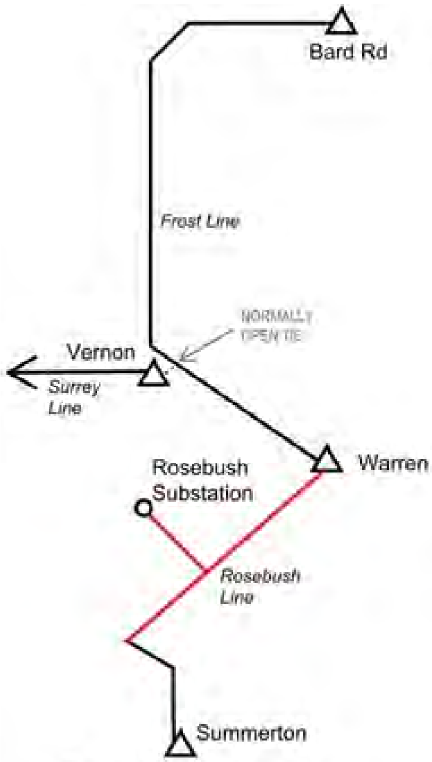
Approved by Timothy J. Sparks on 2/25/2018 8:33 PM

Comment: Approved. The Rosebush 46 kV line has been near impossible to maintain for decades due to inadequate right of way and uncooperative property owners along its route. This project will reroute this line out of the problem area and connect the 46 kV system in a more resilient configuration.

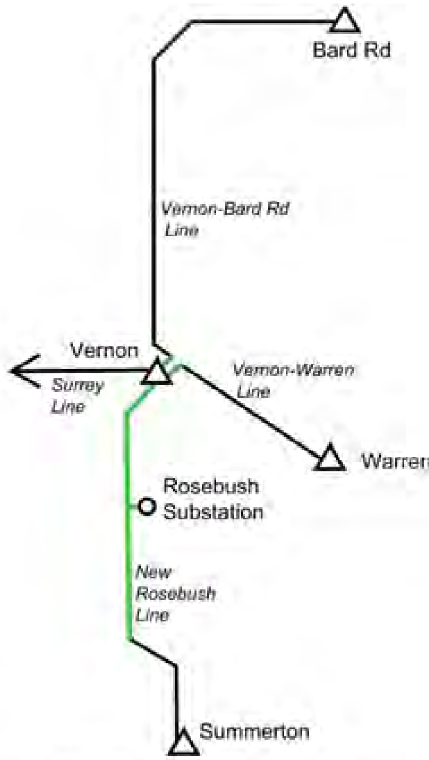
Approved by Jean-Francois Brossoit on 2/26/2018 3:43 PM
Comment:

Approved by Patricia K. Poppe on 2/27/2018 6:40 PM
Comment:

View the workflow history.

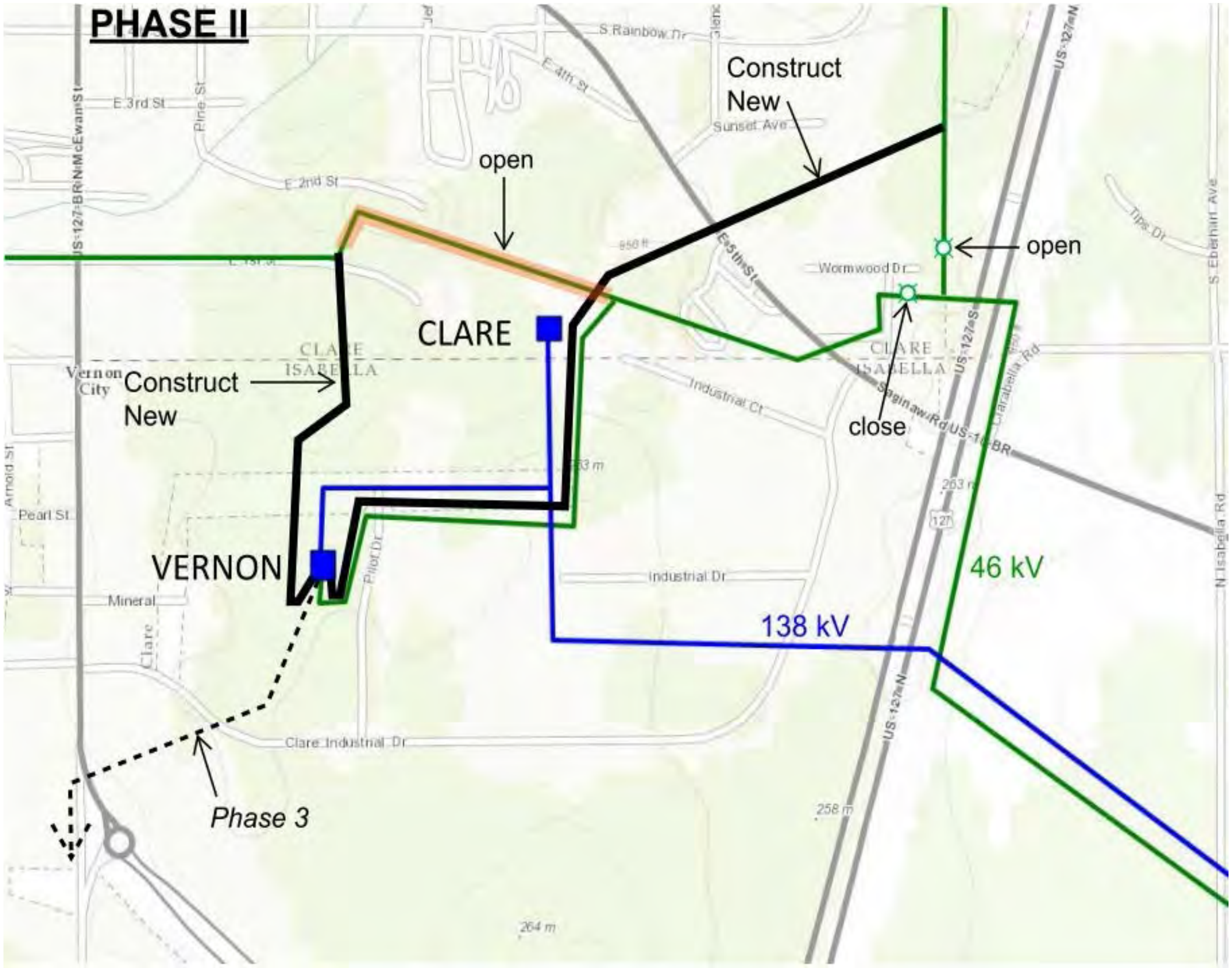


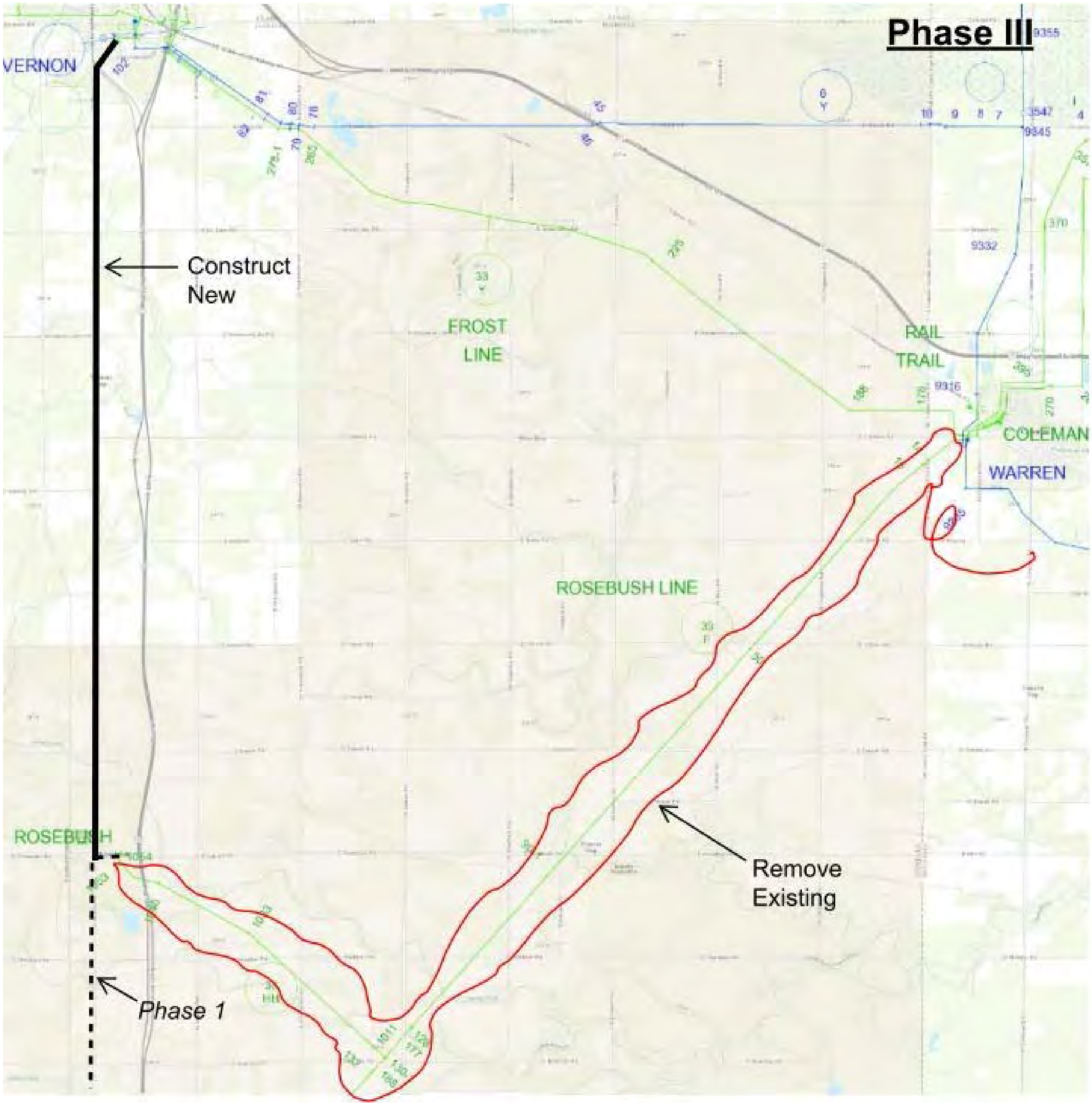
Present 46 kV Configuration



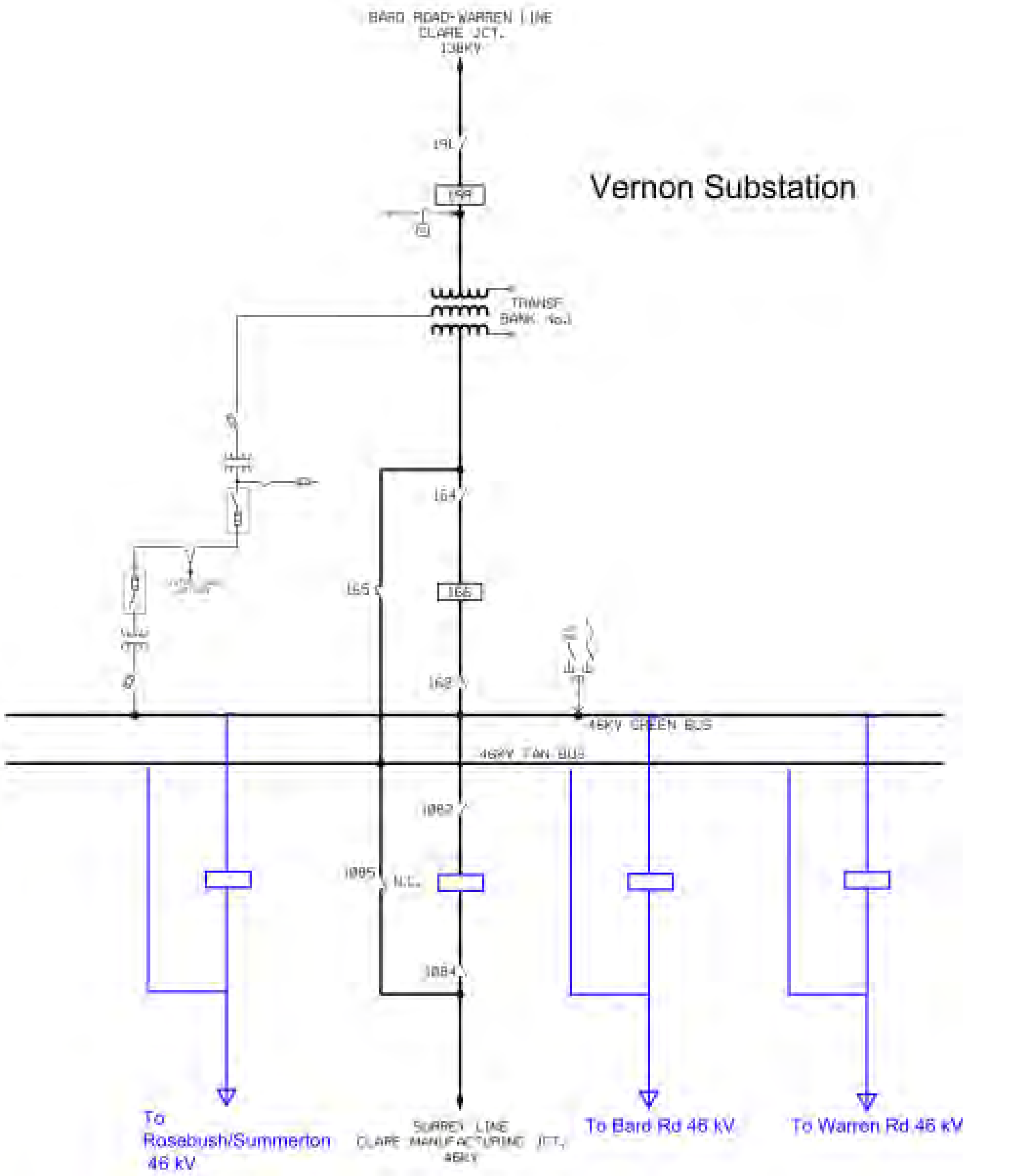
Proposed 46 kV Configuration


PHASE I
ROSEBUSH
E Rosebush Rd
1033
33
HH
1011
128
132
Construct New
ROSEBUSH LINE
Remove
Existing
726
Mount Pleasant
Municipal
Airport
1km
1mi
Map Scale 1:
Enter


PHASE II
Construct New
open
open
CLARE
Construct New
close
VERNON
46 kV
138 kV
Phase 3



Phase III
VERNON
Construct New
FROST LINE
RAIL TRAIL
COLEMAN
WARREN
ROSEBUSH LINE
ROSEBUSH
Remove Existing
Phase 1



BARD ROAD-WARREN LINE
CLARE JCT.
138KV
Vernon Substation
19L
19R
TRANSF
BANK No.1
164
165
166
162
46KV GREEN BUS
46KV TAN BUS
1082
1085
N.C.
1084
To
Rosebush/Summerton
46 kV
SURREY LINE
CLARE MANUFACTURING JCT.
46KV
To Bard Rd 46 kV
To Warren Rd 46 kV

Example 3: LVD Lines Capacity

Consumers Energy
LVD Planning
CONCEPT APPROVAL

Notification Concept Number: 1041345703

Project Title: DARE Lincoln Greenbush Long Range Plan: LVD **Work HQ:** Tawas

Date: December 27, 2019 **Proposed Year of System Changes:** 2021

Problem Description:

Lincoln Substation is planned to be replaced as described and approved in concept approval 18-0025 Lincoln Greenbush Long Range Plan: Lincoln Rebuild. This plan is further described, including alternatives not selected, in the Lincoln-Greenbush Long Range Plan. The existing Lincoln Substation is 11 kV delta surrounded by 14.4/24.9 kV wye grounded. The proposed substation will be 14.4/24.9 kV. In order to transfer the LVD circuits from the existing Lincoln Substation to the new Lincoln Substation, work is required on the LVD circuits to convert from an 11 kV delta supply to 14.4/24.9 kV.

Additionally, both Lincoln and Greenbush are served by approximately 11.2 miles of a poor performing, aged, and non-standard construction radial 46kV line, negatively impacting their reliability. The 46 kV outages and distribution outages continually place Greenbush Substation in the bottom 10% of circuits based on reliability performance.

Finally, the 11 kV delta voltage is non-standard and poses a wiredown safety risk. Delta systems require two phase-ground faults to be present before the phase protective device operates/trips, which means a downed delta wire will not trip a primary protective device until a second phase fault develops.

Alternative Solutions:

1. Lincoln Substation is being rebuilt in place with a 10 MVA 138 kV-14.4/24.9 kV transformer with four LVD circuits. This new substation can also retire Greenbush Substation. Below are the details of the work required to convert the voltage from 11 kV delta to 14.4/24.9 kV wye.

    - Lincoln Substation, Mikado Circuit: Convert the voltage 5 miles downstream south of the substation to LCP 790 from 11 kV delta to 14.4/24.9 kV wye. Change all isolators from 11 kV delta/4.8 kV wye to 14.4 kV wye/4.8 kV wye. Transfer downstream of LCP 959 to Cedar Lake Substation, Kings Corner Circuit. The voltage in this area is the same therefore no voltage conversion is necessary. Transfer the converted circuit to the new circuit exit #4.

- Lincoln Substation, Lost Lake Circuit: Convert the voltage for 9 miles downstream of LCP 639 and transfer to Hubbard Lake Substation, Miller Road Circuit. Install isolators north of the Lincoln Substation at LCP 633. This will be circuit #3 of the new substation. Build a double circuit 3/0 ACSR line east of the Lincoln Substation for 3 miles. Convert the voltage along the three miles from 11 kV delta to 14.4/24.9 kV wye and from 4.8/8.32 kV wye to 14.4/24.9 kV wye. This will be circuits #1 and #2 of the new substation. Circuit #1 will be the top gain and circuit #2 will be bottom gain.

- Greenbush Substation, Harrisville Circuit: Convert 5 miles from Greenbush Substation to LCP 066 from 11 kV delta to 14.4/24.9 kV wye. Install a 14.4 kV wye/11 kV delta isolator east of LCP 375. Once voltage is converted, transfer Greenbush Substation, Harrisville Circuit, to the new substation, Circuit #2.

- Greenbush Substation, Greenbush Circuit: Convert the voltage of all 14 miles of 11 kV delta sections on Greenbush Substation, Greenbush Circuit, from 11 kV delta to 14.4/24.9 kV wye. Replace all 11 kV delta/4.8 kV wye isolators with 14.4 kV wye/4.8 kV wye isolators. Once voltage is converted, transfer Greenbush Substation, Greenbush Circuit, to the new substation, circuit #2. The Greenbush Substation can then be decommissioned. By converting to 14.4/24.9 kV, automation loops with surrounding 14.4/24.9 kV substations will now be possible.

Estimated Design Hours = 11,160

Estimated Loaded Cost = $5,729,800

2. This is the same as Alternative #1 except there will be only three LVD circuits fed by the new substation. This would eliminate the need for double circuit construction east of Lincoln Substation. However, this alternative will have longer circuits due to having only three LVD circuits instead of four.

Estimated Design Hours = 9,688
Estimated Loaded Cost = $4,973,800

Recommended Alternative:
Alternative # 1 is recommended. Alternative #1 is preferable to Alternative #2 because the distribution area would be divided between four circuits instead of three. Alternative #2 in the final configuration has a circuit that is about 130 miles long. This is a high circuit length that would have a negative impact on reliability due to the increased line exposure in heavily wooded areas. It will also create longer service restoration times due to the length of the circuit that would need be investigated. Another major benefit of Alternative #1 is the possibility for automation loops once all the voltage is converted at the end of the approved Lincoln – Greenbush Long Range Plan. Three automation loops are possible and would keep the towns of Greenbush, Lincoln, and Harrisville online in the event of a circuit lockout. This would reduce outage times, especially considering the remote location of the study area. Alternative #2 only has the possibility of two automation loops. In addition, Alternative #1 provides increased load capacity for future growth in the area and achieves a company objective of reducing the amount of circuit miles operating delta and replaces it with a standard voltage. The City of Harrisville has recently approved growing recreational and medical marijuana. Alternative #1 will put Consumers Energy in a better position to provide capacity to this new industry.

Conceptual Estimate:

Program	Loaded Cost	Plan year	Description
LVD Capacity	$1,190,700	2021	• Convert the voltage at Lincoln/Lost Lake LCP 639, transfer to Hubbard Lake/Miller Rd. • Convert Greenbush/Greenbush LCP 503J; transfer to Cedar Lake/Kings Corner. • Transfer Lincoln/Mikado LCP 959 to Cedar Lake/Kings Corner
LVD Capacity	$1,895,900	2022	• Build 3 miles of three phase double circuit east of Lincoln Substation. • Convert the voltage 3 miles east of the substation along path of double circuit • Install isolators just north of Lincoln Substation. • Transfer circuit 2 (formerly Lost Lake) downstream of LCP 902 on to Spruce Road Substation Black River Circuit • Convert the voltage on the Mikado Circuit from Lincoln Substation 2 miles south to LCP 991
LVD Capacity	$928,300	2023	• Convert circuit #4 (formerly Mikado) from LCP 991 to LCP 790
LVD Capacity	$524,100	2024	• Convert the voltage on Greenbush/Greenbush from Greenbush Substation to LCP 544, transfer to new circuit #4, and decommission Greenbush/Greenbush • Transfer Greenbush/Harrisonville on to circuit #2. Install isolators at LCP 374 and LCP 375, and decommission Greenbush/Harrisville circuit
LVD Capacity	$1,190,800	2025	• Convert the voltage at new circuit #2 from LCP 374 to Greenbush Substation • Transfer new circuit #4 from LCP 544 on to circuit #2 • Transfer Cedar lake downstream of LCP 522 back to Circuit #2
Project Total	$5,729,800		

Present Need: On approval, this document authorizes the Low Voltage Distribution Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

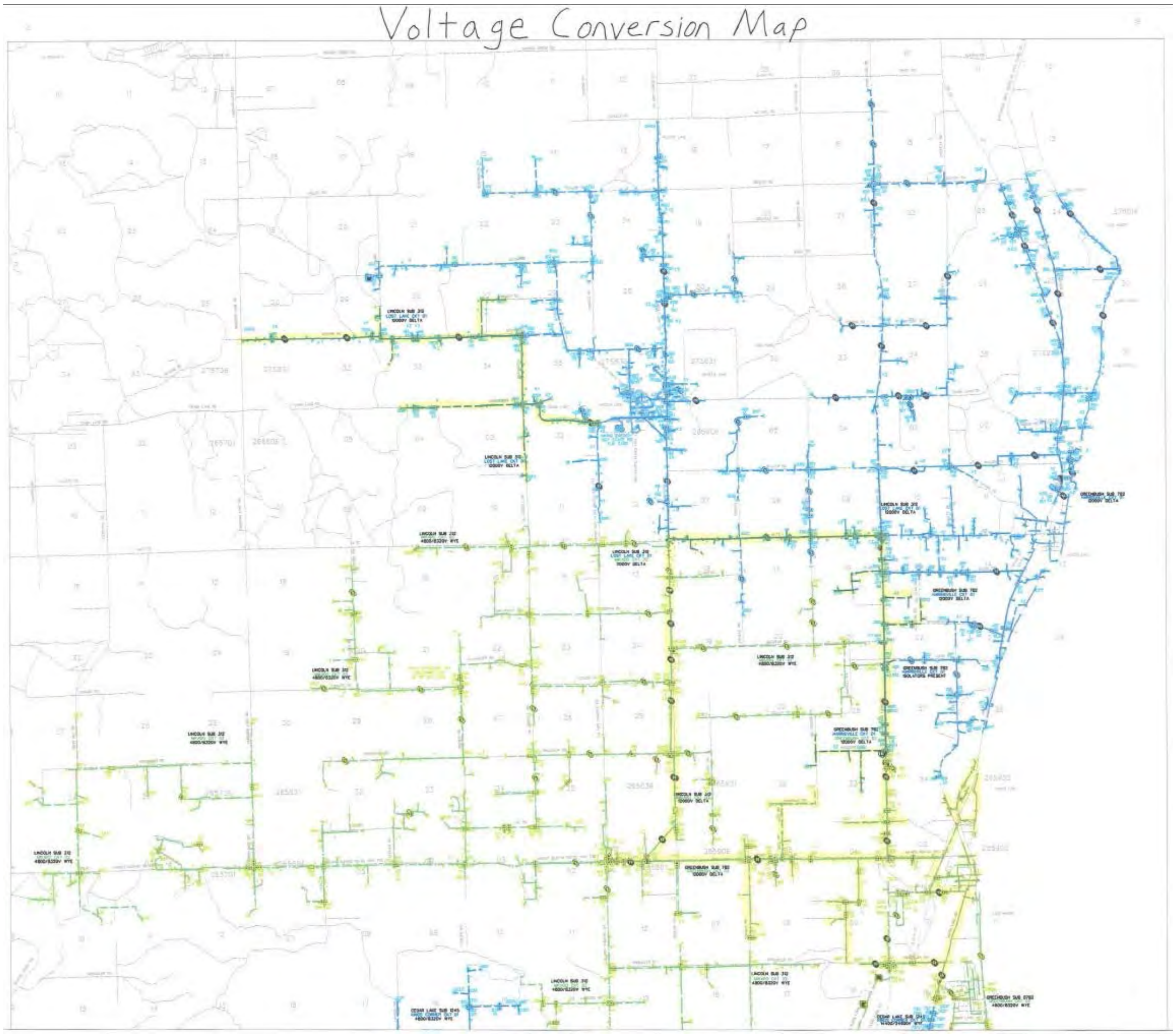
Circuit Owner: Amy P Merrick **System Engineer:** JLBirchmeier

Approvals:

Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald A. Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Transformation, Engineering & Operations Support	Jean-Francois Brossoit	Required
President and Chief Executive Office – CMS Energy	Patricia K. Poppe	Required

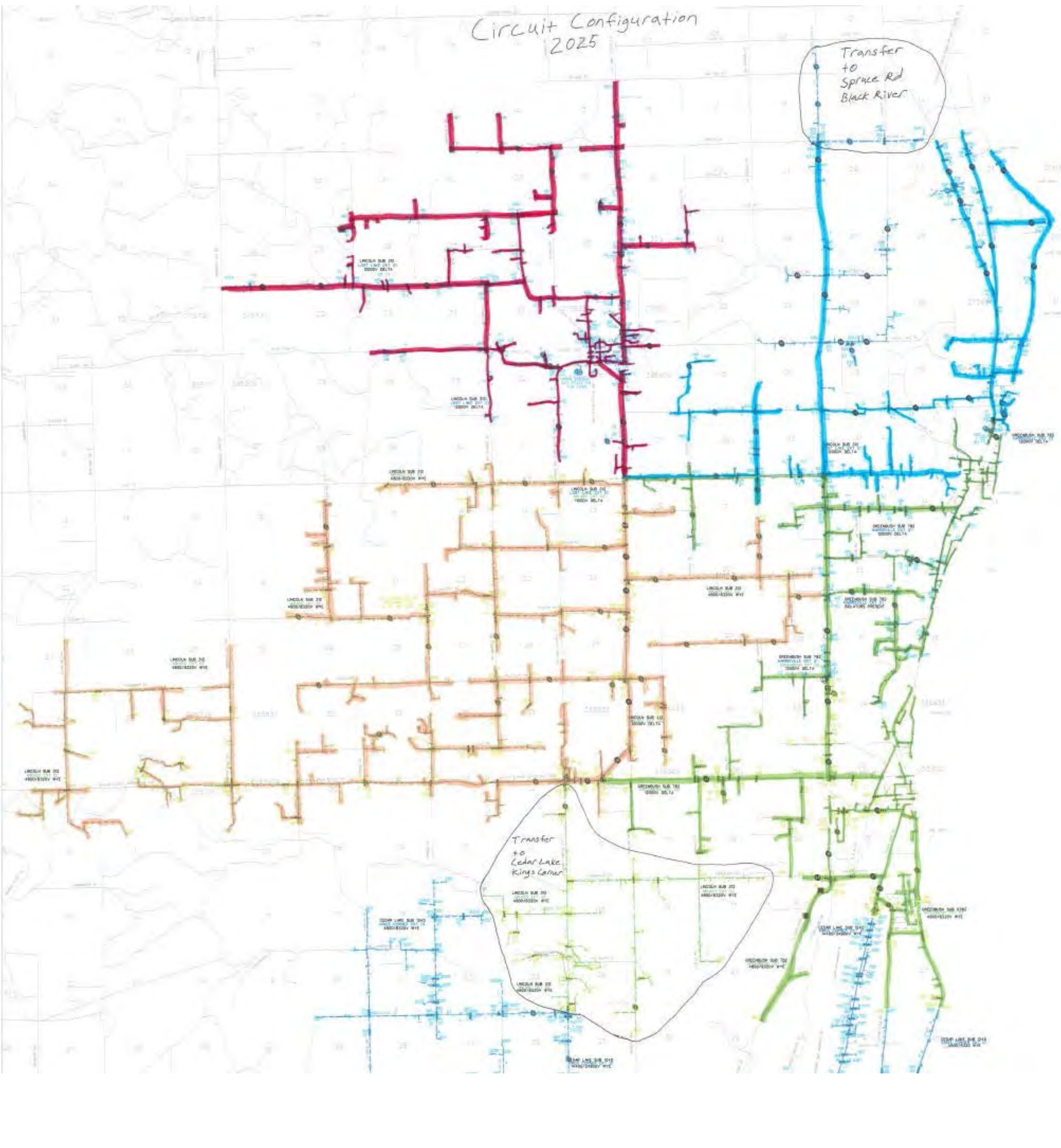
Scope Map:

Areas the voltage will be converted on Lincoln and Greenbush Substations are highlighted:



Configuration in 2025:

Circuit 1 = Blue
Circuit 2 = Green
Circuit 3 = Red
Circuit 4 = Orange



Map of LVD work by Year:

Approval has completed on [DARE Lincoln Greenbush Long Range Plan: LVD].

Approval on DARE Lincoln Greenbush Long Range Plan: LVD has successfully completed. All participants have completed their tasks.

Approval started by Joshua L. Birchmeier on 12/6/2019 4:12 PM Comment:
Please review and approve/reject the proposed LVD concept.

Approved by Joshua L. Birchmeier on 12/6/2019 4:13 PM
Comment:

Approved by JULIA R. FOX on 12/9/2019 6:41 PM Comment:
Approved

Approved by DONALD A. LYND on 12/12/2019 8:03 PM
Comment: Approved. This multi-year project fulfills a voltage conversion objective and permits retirement of a substation and miles of radial 46 kV line.

Approved by RICHARD T. BLUMENSTOCK on 12/17/2019 12:20 PM
Comment: Approved. Links to a related concept approval and a supporting long range plan report are included. So, too, are maps of the area before and after substation and circuit conversions.

Approved by Timothy J. Sparks on 12/18/2019 12:37 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 12/19/2019 1:05 PM Comment:

[View the workflow history.]

Approval has completed on DARE Lincoln Greenbush Long Range Plan: LVD.

Approval on DARE Lincoln Greenbush Long Range Plan: LVD has successfully completed. All participants have completed their tasks.

Approval started by Joshua L. Birchmeier on 12/19/2019 2:52 PM
Comment: Please review and approve/reject the proposed LVD concept. Approval through JF was completed under a separate workflow. Approval sheet is attached to the concept.

Approved by Patricia K. Poppe on 12/27/2019 12:11 PM
Comment:

View the workflow history.

Example 4: HVD Lines and Substations Capacity

Consumers Energy
Customer & Service Infrastructure - HVD
CONCEPT APPROVAL

Concept Number: 20-0059 County: Arenac

Project: Santiago Substation – Au Gres Commercial Marijuana Facility

Date: 06/16/2020 Need System Changes By: 06/31/2021

Problem Description:

Au Gres township passed a medical marijuana facilities ordinance in 2018. Electric Planning completed the necessary LVD line upgrades to provide the final 1.3MW of available 46kV HVD capacity at Au Gres substation (6 MW total). Substation OCR's are being replaced in order to meet the additional capacity. Due to the insufficient footprint of the Au Gres substation, the new reclosers are being installed in a non-conventional configuration outside the substation fence mounted on a pole. The final 900kVA of 46kV HVD capacity (Standish line) at Bessinger substation has been allocated to marijuana facilities (3 MW total). This leaves no capacity left on the Standish 46kV line in the Omer area, with the current system configuration. In addition, Turner and Noble substations have less than 1MVA of available 46kV HVD capacity each.

There are additional facilities in Au Gres and Omer area that have contacted Consumers Energy to determine what electrical capacity is available. With the electrical capacity depleted in the area, we are informing customers to seek alternative methods to meet their electrical needs including natural gas and diesel generators until we can construct a new substation.

Both Au Gres and Bessinger substations need upgrades due to their age and delta supply voltage. Additionally, these substations do not meet the standard safety or design specifications we follow today due to limited clearances between equipment.

Future Growth:

With the recent passage of the marijuana ordinance in Au Gres the load growth has exceeded our capacity on the LVD system, Substation, and HVD system. There are 5 customers requesting a total of MVA that would connect to the electric utility if there was capacity. Currently, the total capacity needed for the Au Gres and Bessinger area is 11.8 MVA. Au Gres township has approved all the allowable grow licenses they have available. Most of these license holders are in the process of working through the requirements set by the state to obtain the approvals to grow. Based on our communication with the township we estimate 35% of the indoor license holders are currently operational. Once these facilities work through the approvals, there will be additional load that cannot be supported by the existing electrical system. Figure 1 (page 6) indicates the parcels which have purchased licenses.

Alternatives Considered:

Alternative 1: Rebuild Au Gres & Bessinger substation

Alternative 1 rebuilds the Au Gres substation with a larger (single) transformer at the current location and converts the circuits from 11kV delta to 24.9/14.4 kV wye. Bessinger substation would also be removed from the 46 kV Standish line and rebuilt in a new location tapped of off the 138kV line.

Based on the contingency results, loading Au Gres to 12MW is not feasible. Both the peak and shoulder cases presented issues, namely that multiple sections of lines were loaded above 100% and numerous buses were below the minimum allowable voltages to operate the system safely and to properly supply our customers. Lower loads were selected to find what the limit on the Au Gres substation was for there to be no contingency problems during the peak case study. This process was stopped at 2.5MW as this would provide very little increase to the current capacity of Au Gres.

The question remained if line rebuilds could help increase the available capacity, and reduce some contingency issues, but it would be a costly expenditure. Given all the issues with the contingencies, it is likely that full, or near to full, rebuilds would need to occur to alleviate these issues. To fully rebuild the Whitestone Point line, it would cost \$12,000,000; to fully rebuild the Alabaster line, it would cost \$18,000,000; and to fully rebuild the Standish line, it would be \$25,000,000. These costs are for the line rebuilds alone, and not for any other potentially needed upgrades for this alternative. Therefore, this alternative was not pursued further.

Alternative 2: Install a new substation near Omer on the 138kV system

This alternative builds a new 20MVA 138-14.4/24.9kV substation on the east side of Omer under the existing 138kV line. Unfortunately, most of the new and existing load is located near the city of Au Gres and it would require LVD to serve 7MVA of load seven and a half miles away from the substation. This limits the new load growth capacity of Au Gres area to 2MVA. At this point the voltage drops below the MPSC mandated limit and Consumers does not stock line regulators large enough to handle the load. This alternative also brings up some reliability concerns. The circuit feeding Au Gres would have a total of 1,530 customers but only 60 customers would be in in the first 7 miles. The first two and a half miles of the first zone will be double circuit construction, an outage on this line will cause the entire substation to lock out affecting 1,961 customers. Therefore, this alternative was not pursued further.

Alternative 3: Install a new substation near M-65 & Noggle Rd on the 138kV system

Alternative 3 builds a new 20MVA 138-14.4/24.9kV substation (see figure 3, shown on page 8) near the intersection of M-65 and Noggle Rd. This will require a two-mile 138kV line extension off Iosco-Karn line (5O), which will include a load break switch and easements. A load break switch is a requirement from METC for lines of 2 miles or longer. METC will need to install a 138kV tap pole and switches on each side of the tap. The substation will allow us to serve all the new additional load along with providing the area with load growth potential. The proposed load for the new substation would be 10.8 MVA based on existing loads. The three new LVD circuits will be 67 miles, 18 miles, and 13 miles in length. See Table 1 on page 9 for circuit characteristics.

The estimated project costs for Alternative 3 are as follows:

- 138kV general distribution substation cost estimate: \$1,800,000
- Substation property acquisition estimate: \$80,000
- Two-mile 138kV line extension, load break switch, and easements: \$1,564,000

- LVD line work required to reach new loads: $2,080,000
- Total: $5,524,000

Alternative 4: Install a new substation on the west side of Au Gres on the 138kV system

Alternative 4 builds a new 20MVA 138-14.4/24.9kV substation (see figure 3, shown on page 8) on Santiago Rd on the northeast corner of the 2497 Huron Rd marijuana facility. Lower property cost is expected at this location due to the property being owned by a marijuana facility with a vested interest in a new substation. The new substation will require a seven-mile 138kV line extension off the Iosco-Karn line (5O), a load break switch, and five miles of LVD underbuild. A load break switch is a requirement from METC for lines of 2 miles or longer. METC will need to install a 138 kV tap pole and switches on each side of the tap. This substation will allow us to serve the new load along with providing the area with potential for load growth. The proposed load for the new substation would be 10.8 MVA based on existing loads. Figure 2 depicts the scout map for the HVD right of way acquisition. The three new LVD circuits will be 32 miles, 46 miles, and 25 miles in length. See Table 1 on page 9 for circuit characteristics.

The estimated project costs for Alternative 4 are as follows:

- 138kV general distribution substation cost estimate: $1,800,000
- Substation property acquisition estimate: $20,000
- Seven-mile 138kV line extension, load break switch, and easements: $5,000,000
- Five miles of LVD underbuild: $555,000
- Total: $7,375,000

Recommended Alternative

Alternative 4 is a path forward that will address current load capacity issues, along with addressing future substation reliability concerns of the area. The new substation will alleviate the HVD system capacity limits which will free up 8 MVA on the surrounding 46kV substations.

Alternative 4 will provide increased reliability compared with Alternative 3 due to the substation being closer to the city of Au Gres where the largest loads and customer counts are located. The 5 mile stretch between Au Gres and M-65 is heavily wooded and swampy. Alternative 3 locates the substation at M-65 which requires the first zone of the circuit feeding the city of Au Gres to be constructed through this area. This would cause additional LVD circuit lockouts along with long restoration times resulting in poor reliability to 78% (circuit 1) of the customers in the area. With the substation located in Au Gres, the circuit feeding Omer (through the wooded and swampy zone) would have much less exposure to these risks due to underbuilt construction. Along with limited exposure, only 25% (circuit 2) of customers would be fed through this territory. Using current reliability data for the lines we do have in this area we expect a 297,000 ($891,000 savings based on $3/min) yearly outage minute reduction with Alternative 4. Using the circuit characteristics shown in Table 1 (shown on page 9), it can be concluded that Alternative 4 provides more balanced circuits for loading, customer-count, and customer miles.

This concept covers the first 2 of 8 years of the Santiago long range plan. The long range plan includes retiring Au Gres and Bessinger substations by voltage converting all the LVD backbone from delta to wye and transferring to Santiago substation. The work covered in this concept is necessary to start the voltage conversion process and to meet immediate substation and HVD capacity needs. The LVD voltage conversions, to be completed on future concepts, can utilize the new business process to complete the appropriate work as needed. These future concepts bring the total cost to $17.2 million as discussed in the long range plan. Please review the attached long range plan for in depth details about the economic analysis, LVD system losses, and future LVD voltage conversion plans.

Conceptual Estimates by WBS

	WBS Element	Direct Cost	Cost with Overheads	Description	Year(s)
HVD	EH-95208	$700,000	$700,000	7 Miles 138kV ROW	2020
HVD	EH-95208	$20,000	$20,000	Substation Property	2020
HVD	ED-95720	$1,200,000	$1,800,000	New 138kV General Distribution Sub	2021
HVD	EH-95008	$2,900,000	$4,300,000	7 Miles New 138kV Line	2021
HVD			**$6,720,000**	**Total HVD Costs**	
LVD	ED-10000		$555,000	5 Miles 138kV Underbuild	2021
			$555,000	**Total LVD Costs**	
TOTAL COSTS			**$7,375,000**	**Total HVD + LVD Costs**	

Present Need: On approval, this document authorizes the C&SI, LVD, and HVD Engineering groups to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Prepared By: Blake Dycewicz & Matt Koepke

Approvals:

Substation Planning & Reliability East	Matthew Good	Required
Interim Director HVD System Planning	Ed Matthews	Required
Director, LVD Circuit Planning	Julia R. Fox	Required
Director, LVD System Planning	Donald Lynd	Required
Executive Director, Electric Planning	Richard T. Blumenstock	Required
Vice President, Electric Grid Integration	Timothy J. Sparks	Required
Senior Vice President, Engineering and Transformation	Jean-Francois Brossoit	Required

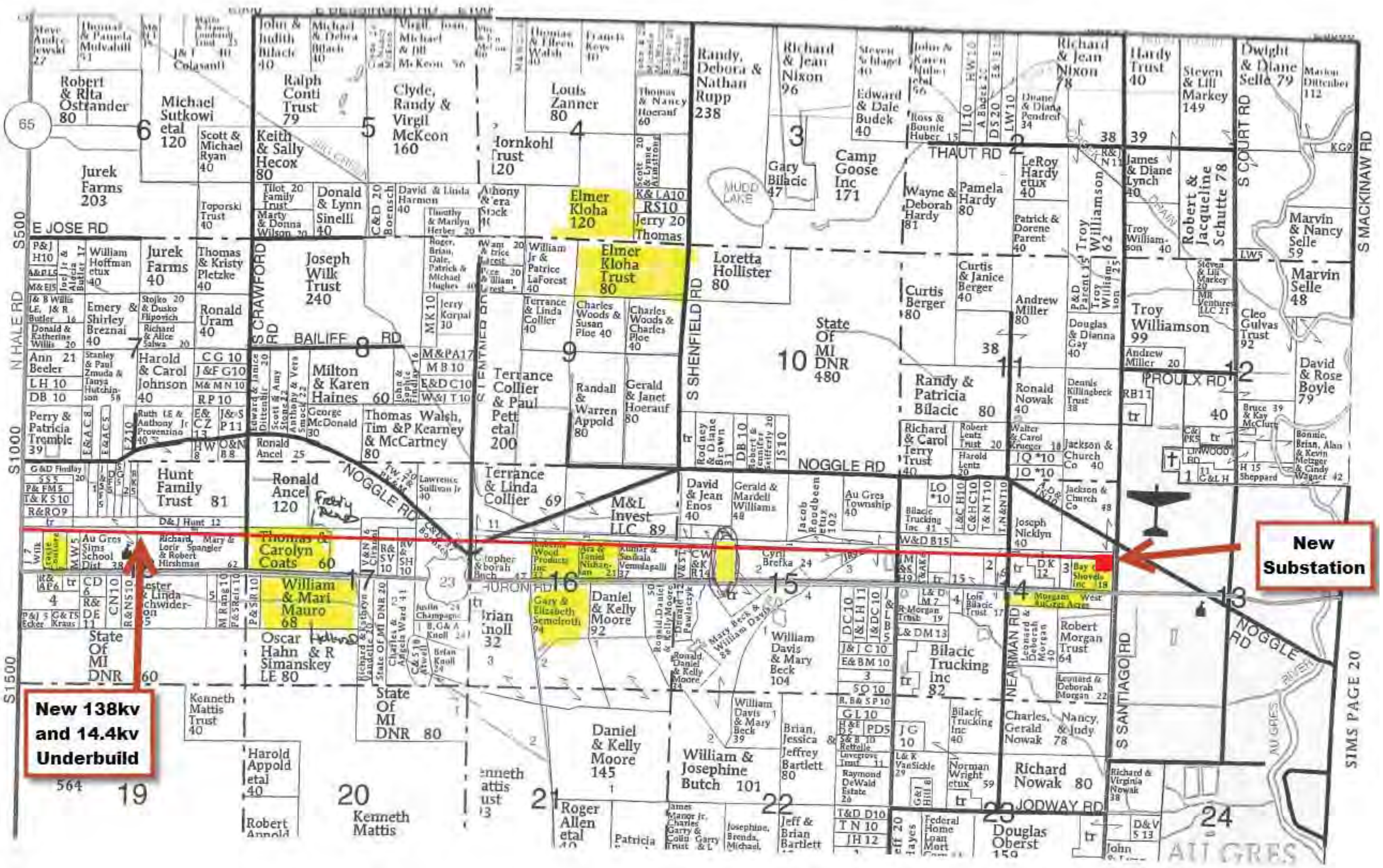


Figure 1: Properties in Au Gres that have Purchased Marijuana Licenses

Figure 2: Alternative 4 Scout Map Area Showing Proposed 138kV Line and Substation

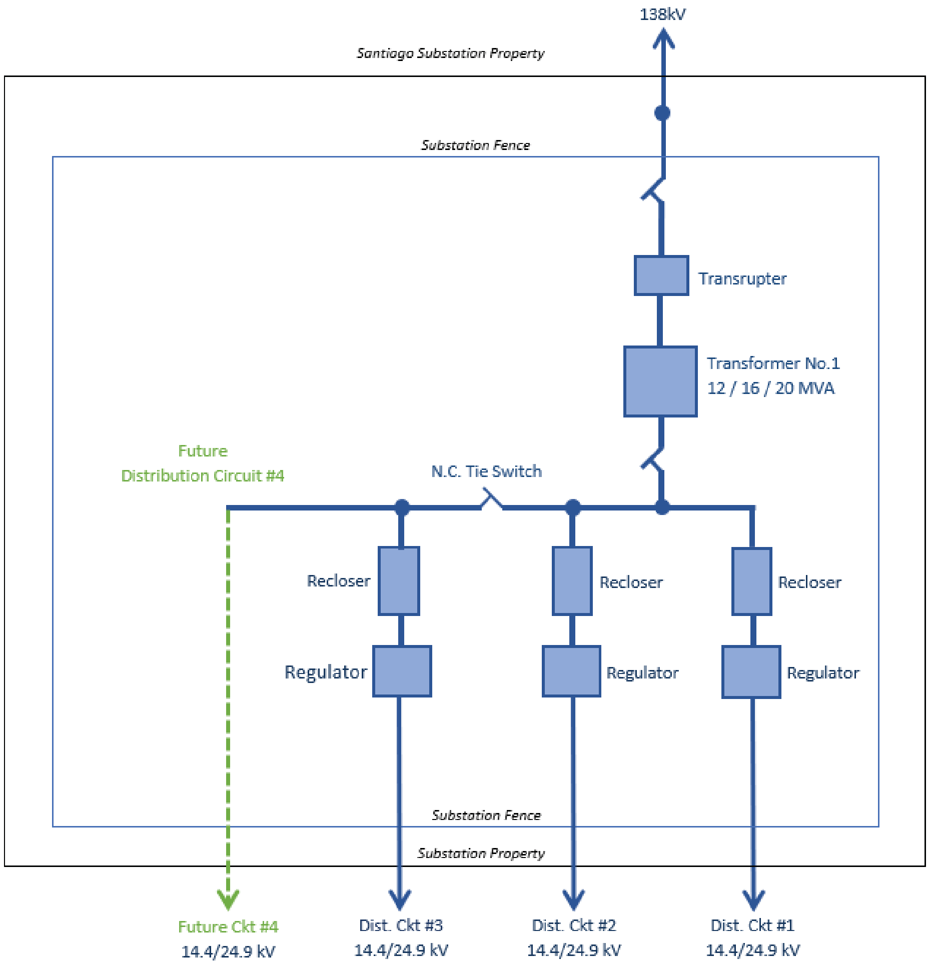


Figure 3: Substation Configuration

Table 1: Circuit Data Breakdown

Alternative 3								
Circuit	**Load (MVA)**	**% Total Load**		**Miles**	**% Total Ckt Miles**		**Customers**	**% Customer Count**
1	8.2	75.9		67	68.37		1530	78.02
2	2.3	21.3		18	18.37		347	17.70
3	0.3	2.8		13	13.27		84	4.28
Total	**10.8**			**98**			**1961**	

Alternative 4								
Circuit	**Load (MVA)**	**% Total Load**		**Miles**	**% Total Ckt Miles**		**Customers**	**% Customer Count**
1	5	46.3		31.5	30.73		596	30.39
2	3.5	32.4		46	44.88		491	25.04
3	2.3	21.3		25	24.39		874	44.57
Total	**10.8**			**102.5**			**1961**	

BRIAN C. MAZUR

From:	SPAdvisor
Sent:	Tuesday, October 6, 2020 8:19 AM
To:	BRIAN C. MAZUR
Cc:	BRIAN C. MAZUR; Ivan E. Principe; ARIC L. ROOT; Edward R. Mathews; Gregory E. Kral; Jacob D. Roberson; Blake A. Dycewicz; Matthew R. Koepke
Subject:	Approval has completed on 20-0059_LVD Substations - Santiago Substation - Au Gres Commercial Marijuana Facilities.

Approval has completed on 20-0059_LVD Substations - Santiago Substation - Au Gres Commercial Marijuana Facilities.

Approval on 20-0059_LVD Substations - Santiago Substation - Au Gres Commercial Marijuana Facilities has successfully completed. All participants have completed their tasks.

Approval started by BRIAN C. MAZUR on 9/11/2020 3:36 PM
Comment: A new document has been added to the LVD & HVD System Planning Project Collection under the approval limit of $20,000,000. Please view the document and approve or comment.

Approved by Matthew D. Good on 9/11/2020 3:37 PM
Comment:

Approved by Edward R. Mathews on 9/14/2020 1:51 PM
Comment:

Approved by JULIA R. FOX on 9/15/2020 7:03 AM
Comment: Approved. The LVD Lines (Underbuild) will be charging to 3.06 New Business Capacity. ED-10000 is a retired WBS.

Approved by DONALD A. LYND on 9/15/2020 7:21 AM
Comment: Approved.

Approved by RICHARD T. BLUMENSTOCK on 9/18/2020 11:59 AM
Comment: Approved. Tim - I will send you the long range plan for this area to supplement this concept approval.

Approved by Timothy J. Sparks on 10/5/2020 9:35 PM
Comment: Approved.

Approved by Jean-Francois Brossoit on 10/6/2020 8:19 AM

Comment:

View the workflow history.

Appendix E

ELECTRIC POWER RESEARCH INSTITUTE

CONSUMERSENERGY GRID MODERNIZATION ROADMAP ASSESSMENT

April 2021

11459247

Executive Summary

The distribution landscape is changing rapidly—introducing new opportunities along with increasing system complexity and uncertainty. This change is being driven by the need to accommodate and integrate distributed energy resources (DER), electric vehicles (EVs), changing customer expectations, shifting load patterns, increased stakeholder engagement, and advanced technologies. The result is a need to update the processes, methods, and technologies used to plan and operate the distribution system. To that end, almost every state has initiated regulatory or legislative efforts to modernize the distribution grid.

Michigan is in the early stages of this process. The Michigan Public Service Commission (MPSC) launched an initiative in 2017 focused on transparent and long-term electric distribution planning. The impetus for this initiative was to increase investment in electric distribution systems and aging electric distribution equipment, to incorporate advanced energy technologies to modernize the distribution system, and to address reliability concerns. In response to the Commission Orders, Consumers Energy (CE) developed its Electric Distribution Infrastructure Investment Plan (EDIIP) which describes a comprehensive distribution investment and maintenance plan spanning a five-year planning horizon. Much like grid modernization efforts nationally, the plan focused on providing safe, reliable, and affordable electricity to its customers.

EPRI has been working with the industry to develop a framework to help utilities with strategies to meet the evolving requirements of a modern grid, leveraging concepts described in the U.S. Department of Energy (DOE) Next Distribution System Platform (DSPx) project. The EPRI framework recognizes that enhancing existing capabilities or developing new capabilities is realized through multiple steps as new tools, processes, systems, and other resources become operationalized. By identifying these steps, a functional progression—a roadmap—can be developed that describes a set of actions a utility will need to undertake to develop the capabilities needed to meet new objectives.

This report describes the application of these frameworks and concepts for modern-day distribution planning and operations to assess the CE Grid Modernization Roadmap. EPRI's assessment looked at the CE plan across several dimensions—the underlying drivers and objectives, the key capabilities needed to realize the objectives, and the implementation plan—to offer insights into how the Roadmap compares with other industry plans. This report is intended to inform stakeholders of current industry practices on this topic. Below are highlights from the assessment.

Stakeholder Engagement

Overall, the CE followed leading practice for roadmap development. Of note, CE engaged stakeholders from across the company and at all levels to help ensure a broad range of perspectives and inputs were collected and a full range of business capabilities are addressed. Broad engagement also begins the socialization and change management process for the Roadmap as a guiding document.

Peer Benchmarking

A grid modernization plan is different for every company. How and when a utility moves from its current to a future state depends on its unique set of drivers and objectives. Benchmarking with peer utilities, however, can provide key insights into how others have structured their grid modernization plans and programs. As part of its roadmap process, CE conducted peer benchmarking to compare its approach with others and to identify lessons learned. Key learnings that CE was able to apply include how to address technology maturity, organizational readiness, and change management. The peer reviews helped to align the Roadmap with leading industry practices.

Roadmap Objectives

Objectives establish the basis for modernization and describe what CE plans to accomplish through the Roadmap. Through its Integrated Resource Plan, EDIIP, and Roadmap, CE has articulated a clear set of objectives ranging from customer experience, to system reliability and the clean energy transition. Objectives convey both scope and timing requirements and subsequently guide the

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Roadmap planning process. Central to CE's modernization approach is a Grid System Orchestrator (GSO) strategy. The GSO strategy outlines a set of future roles and capabilities that will be needed to meet objectives in the functional areas of grid operations, grid planning, grid infrastructure management, distributed energy resource management, and market operations. The GSO provides a comprehensive functional framework to guide the organization and prioritization of the Roadmap. The resulting Roadmap presents a clear logic that links the proposed implementation plan and priority back to the GSO strategy and stated objectives.

Business Capabilities

Capabilities are the collection of expertise, processes, tools, and technologies that a utility will need to execute a specific course of action. Identifying the capabilities needed to support grid modernization is an essential yet complex process. New or enhanced capabilities will be needed to support core utility functions (planning, operations, infrastructure), cross-cutting functions (telecommunications, cyber security, and data management) as well as business function (change management, work management, etc.). Defining the capabilities needed is perhaps the most important component of the Roadmap process. CE used an experienced-based reference model which describes a comprehensive inventory of 270 business capabilities needed to effectively operate an electric distribution business and created an accompanying logical architecture to identify the associated technologies needed to enable the capabilities ranging from the edge of the grid (customers and field devices) to back office systems. The reference model helps to ensure that all potential capabilities are considered; the architecture likewise helps to ensure that the associated technology and connecting infrastructure and networks are also identified. EPRI's experience would indicate that CE's use of a business capability model and architecture was an industry leading practice among utilities that are developing grid modernization plans.

Proportional Deployment Strategy

The DOE DSPx materials introduced the concept of a proportional deployment strategy (i.e., provide advanced grid capabilities where most needed first and/or initially improve grid function with known solutions, followed by more advanced approaches at a later time, as needed). The CE Roadmap applies this concept by focusing the first phase (0–2 years) on foundational capabilities that are expected to have the greatest impact.

CE articulates the importance of piloting applications in the first phase and learning-as-you-go approach. The Grid Mod Incubator initiative is a good example of this, providing an integrated platform for evaluating the safety, security, and interoperability of new technologies, without impacting customers or other equipment before deploying on the distribution system. CE's engagement with industry collaborative research, such as with EPRI, is another way in which CE is staying abreast of the technology trends and leveraging national research efforts to develop and apply new technology.

The second phase of the Roadmap (2–5 years) begins to focus on further developing core capabilities in operations, planning, and the supporting systems and processes needed to build out the GSO capability. The third phase (5–10 years) will depend on how market conditions and regulatory processes evolve. The Roadmap presents a measured approach to modernization, starting with core capabilities in the first five years that will provide value regardless of how the next five years evolve.

Data Governance and Management

Leading utilities, like CE, are beginning to treat data as a strategic asset and establishing enterprise-wide approaches to data governance and management. Accurate distribution system models will become more critical as DER penetration levels increase and as distribution grids grow increasingly complex. Data will come from across the enterprise; will be used across the enterprise; and will need to be managed across the enterprise with a much higher level of granularity, integrity, and speed. Recognizing the importance, CE has established roadmap initiatives to ensure the appropriate policies, procedures, and controls are in place to manage distribution data.

Asset Management

Distribution systems are composed of many assets that are distributed over a wide geographic area. Many of these assets are near or past their expected service life, while new electronic devices are also being added to the system. Each type or class of asset requires a strategy that defines the necessary actions over short-, mid-, and long-term time horizons to optimally manage the asset lifecycle—how and when the asset should be maintained, repaired, or replaced. With the Roadmap, CE lays out a comprehensive, industry-leading approach to leveraging data science approaches to improve system reliability and fleet management decisions.

Cyber Security

As grid modernization infrastructure is implemented with increasing connectivity and information flow internally and with others externally, the attack surface for any potential adversary increases. Recognizing this, modernization strategies should address the need to enhance and extend cyber defenses and evolve into a proactive deterrence rather than the traditional reactive defense. Through its modernization efforts, CE is establishing a cyber security standards and control framework from the start such that critical capabilities and gaps in operational technology cyber security are identified and incorporated into the overall design, deployment, and operation of each project as they are deployed over time.

Workforce

As the distribution system becomes more complex, the roles of distribution engineers, operators and field workers will also evolve. Utilities across the country are beginning to rethink job functions and define the new skillsets and tools that will be needed in the future to evolve the workforce. This aspect is not often addressed in utility roadmaps which tend to be more technology focused. Through its workforce related initiatives, CE has anticipated this change and is addressing how work is managed as well as the digital tools workers will need use to improve efficiency and performance.

Overall Summary

Developing a strategy for grid modernization is complicated. Investments are significant and must be sequenced over several years to achieve both the foundational requirements of safely delivering low-cost, reliable electricity service while also adding new capabilities. EPRI has worked with electric utilities to develop company-specific strategic roadmaps for more than 15 years. In comparison with other utility roadmaps, and with industry frameworks, such as the DOE DSPx and the EPRI Grid Modernization Playbook, CE has taken a comprehensive approach with its Roadmap. CE is addressing core capabilities in operations, planning and grid infrastructure as well as key supporting capabilities, such as telecommunication, cyber security, grid data, and work management which are essential to grid modernization.

Introduction

The distribution landscape is changing rapidly—introducing new opportunities along with increasing system complexity and uncertainty. The changes are being driven by several factors with common themes being the integration of distributed energy resources, changing customer expectations, decarbonization, increasing severity and impact of extreme weather events, and increasing stakeholder engagement. As a result, regulatory or legislative efforts are underway across the U.S. to modernize the distribution grid.

Some states, like California and New York, are several years into comprehensive modernization efforts and are actively integrating advanced grid technologies; defining new planning and analytical methods; defining and deploying new technologies to operate the grid; and developing processes to fully integrate DER. In other states, like Minnesota, the grid modernization efforts to date have focused more on future methods and tools for distribution planning. Ohio also recently completed an initial roadmap for grid modernization through a stakeholder process called PowerForward. In Illinois, the state commission initiated more comprehensive modernization efforts and asked utilities to lay out their plans for grid modernization over the next five years so that stakeholder input can be solicited.

Michigan is in the early stages of this process. The MPSC launched an initiative in 2017 focused on transparent and long-term electric distribution planning. The impetus for this initiative was to increase investment in electric distribution systems and aging electric distribution equipment, to incorporate advanced energy technologies to modernize the distribution system, and to address reliability concerns. In response to the Commission Orders, CE developed its Electric Distribution Infrastructure Investment Plan[1] which describes a comprehensive distribution investment and maintenance plan spanning a five-year planning horizon. Much like grid modernization efforts nationally, the plan focused on providing safe, reliable, and affordable electricity to its customers.

Looking ahead, CE expects to file its next EDIIP in June 2021. Its current grid modernization activities are at a point where adjustments and additional investments are needed to further enhance the capabilities, reliability, and resiliency of the grid and to also achieve ambitious clean energy goals. To help inform the next plan, CE developed a Grid Modernization Roadmap[2] which looks ahead to provide a more detailed and progressive strategy for the future investments needed over the next 10 years to achieve their objectives.

1 Consumers Energy Company's Electric Distribution Infrastructure Investment Plan, April 13, 2018.

2 Consumers Energy Grid Modernization Roadmap – Final Report, April 8, 2020.

CE asked EPRI to conduct an independent review of the Roadmap to compare how the plan aligns with broadly accepted frameworks for grid modernization (EPRI, DOE, other utilities, etc.); assess the key initiatives and associated capabilities; evaluate the timing and execution plan; and to provide insights into potential gaps or general areas of improvement. This report documents the finding from the assessment.

Grid Modernization Frameworks

U.S. Department of Energy (DOE)

The DOE Office of Electricity Delivery and Energy Reliability, at the request of and with guidance from several state commissions, began working with state regulators, the utility industry, and others to develop a foundational definition and understanding of a modern distribution grid. More specifically, the effort aimed to determine the functional requirements for a modern grid that would enable higher reliability and resilience while also enabling integration and utilization of DER. Called the “Next-Generation Distribution System Platform (DSPx) Project,” the objective was to develop a consistent understanding of the requirements to inform investments in grid modernization toward those objectives.

The DSPx project results are a useful to understand and organize the interrelationship of technology investments needed in a modernized distribution system. In that regard, over twenty-four regulatory commissions and utilities have leveraged the Modern Distribution Grid reports[3] to inform regulatory proceedings. The DSPx framework provides a recognized industry reference for aligning and assessing utility grid modernization plans and communicating how it is sequencing investments to yield the greatest near- and long- term value and interoperability of utility systems while preserving the flexibility to adapt to an evolving customer and technology landscape.

It also developed the concept of the distribution system as a platform which describes how core infrastructure and advanced technology investments can build on each other to achieve primary

3 Based on various state commission requests and utility feedback and filings.

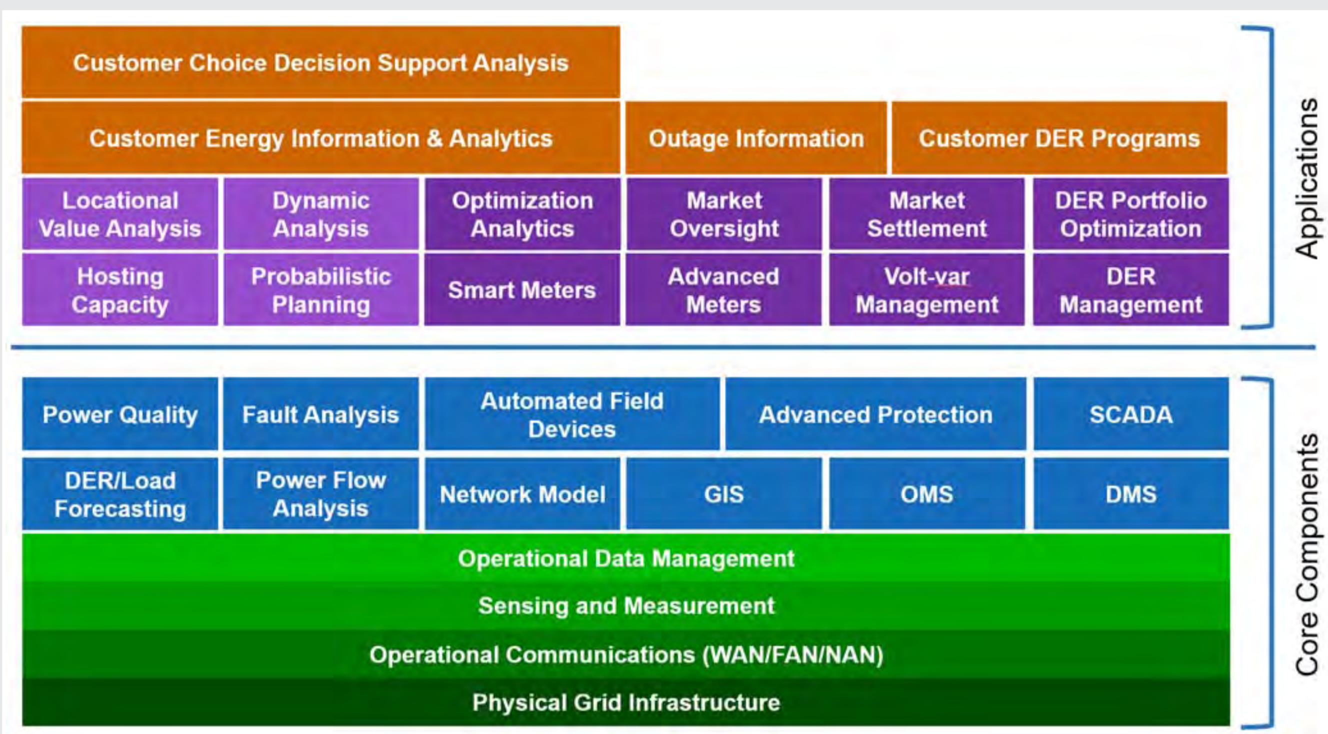

Figure 1. Next Generation Distribution System Platform and Applications

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outcomes of improved safety, reliability, and cost while also preparing for a more complex future with a dynamic and integrated electric grid. This platform concept, illustrated in *Figure 1*, depicts a "building block" relationship between the core components, which form the foundation, and future applications that are dependent on the core.

EPRI Framework

EPRI has also been working with industry to develop a framework[4] to help utilities with strategies for grid modernization and developing the capabilities needed to meet the evolving requirements of a modern grid. Leveraging the concepts described in the DSPx project,[5] the EPRI framework describes a structured methodology and a set of tools to help utilities develop or assess plans to meet a company's unique objectives. It recognizes that enhancing existing capabilities or developing new capabilities is realized through multiple steps as new tools, processes, systems, and other resources become operationalized. By identifying these steps, a functional progression—a roadmap—can be developed to provide a set of actions a utility will need to undertake to develop the capabilities needed to meet defined goals.

EPRI's Integrated Grid[6] and Integrated Grid Benefit-Cost Framework[7] are additional industry resources which define the key steps necessary to move toward an Integrated Grid—one that enables utilities to realize the full value of DER, integrating DER into every aspect of grid planning, operations, and policy. The Benefit-Cost Framework presents a transparent, consistent methodology for assessing the benefits and costs of transitioning to an Integrated Grid.

Roadmap Assessment

Comparing the CE Roadmap with the EPRI and DSPx frameworks provides a good benchmark for assessing both the components and the timing and pace of its grid modernization plan. EPRI's assessment looked at the CE plan across several dimensions. First, it looked at the overall CE Roadmap process, the underlying drivers and objectives for distribution modernization, and the key capabilities needed to realize the objectives. Next, it assessed the plan with a focus on the technology modernization components in the context of how the capabilities align with and support stated objectives. And finally, the assessment identified gaps or overall areas of improvement and insights into how the Roadmap compares with other industry plans.

A first step in developing or assessing a grid modernization strategy is to understand the drivers and objectives for modernization. Drivers are the factors that are compelling change in current practices for which a utility currently plans, designs, operates, and maintains the distribution system. Drivers can be external, such as regulatory or legislative policy or changes in customer behavior or can be derived from corporate business strategy. Objectives define the specific result that the utility wants to achieve. Therefore, objectives drive the subsequent steps in the roadmap process and decisions in the system characteristics that must change, such as improving existing capabilities or adding new capabilities. With this as a foundation, modernization plans can then identify the capabilities needed to achieve each objective, as well as the roadmap to get there.

The CE Roadmap process followed leading practice for roadmap development. Key steps in the process are described in *Figure 2*. Of note, CE engaged stakeholders from across the company and at all levels to help ensure a broad range of perspectives and inputs were collected. Through a series of workshops with subject matter experts, leaders, front-line workers, and support organizations, CE gained insights into corporate vision and strategy, the current state of capabilities, and future needs of processes, systems, and organizational approach from across the company. The workshops identified existing capabilities, initiatives, gaps, and key findings which informed the subsequent capability prioritization and roadmap initiatives.

Engaging such a broad range of stakeholders helps ensure that the roadmap addresses a full range of business capabilities from core capabilities (grid infrastructure, operations, and planning) to supporting technology (cyber security, telecommunications, etc.). Broad engagement also begins the socialization and change management process for the roadmap as a guiding document.

Current State Assessment

The current state assessment was focused on areas that were expected to have the greatest impact on CE objectives, such as substation and distribution automation, DER integration, advanced distribution

4 *Grid Modernization Playbook: A Framework for Developing Your Plan*. EPRI, Palo Alto, CA: 2020. 3002018952.

5 Modern Distribution Grid, Volumes I-IV, U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

6 *The Integrated Grid*. EPRI, Palo Alto, CA: 2015. 3002002733.

7 *The Integrated Grid: A Benefit-Cost Framework*. EPRI, Palo Alto, CA: 2015. 3002004878.

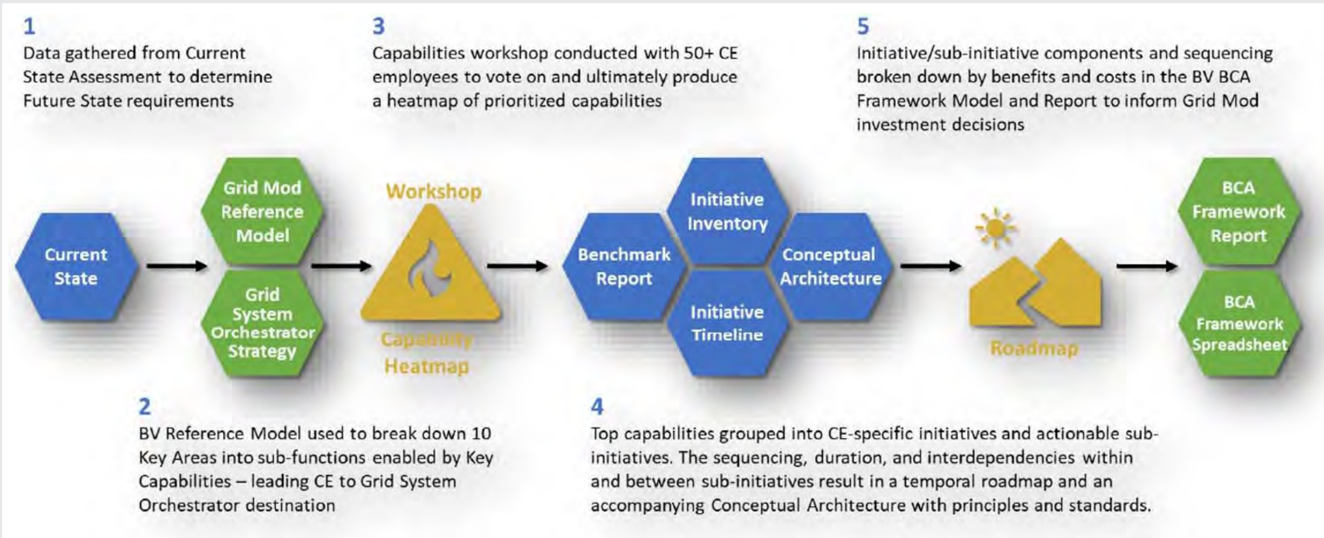

Figure 2. Roadmap Development Approach. (Source: Consumers Energy Grid Modernization Roadmap)

management systems (ADMS), and distribution asset/work management. Like many electric utilities, CE is still in the early stages of grid modernization, focusing on establishing the foundational infrastructure and improving overall system reliability. For example, CE has installed thousands of devices on the system which are already delivering reliability benefits to their customers. However, there were gaps in future technologies, processes, organization, and data management that limit the potential benefits of grid modernization. The current state assessment provided critical insight into areas where CE will need to focus grid modernization efforts.

Peer Benchmarking

A grid modernization plan is different for every company. How and when a utility moves from its current to a future state depends on its unique set of drivers and objectives. Benchmarking with peer utilities, however, can provide key insights into how others have structured their grid modernization plans and programs. As part of its roadmap development process, CE conducted peer benchmarking to compare its Roadmap approach with others and to identify lessons learned. Through this process, CE identified several key learnings—how to address technology maturity, organizational readiness, and change management—that were incorporate into the Roadmap. The peer reviews also helped to align the Roadmap with leading practices from across the industry.

Drivers and Objectives

The starting point for the Roadmap was alignment of modernization objectives with the CE's vision—the strategy that drives modernization decisions. With its 2019 Integrated Resource Plan (IRP),[8] CE established a triple bottom line strategy —People, Planet, and Prosperity— to balance the interests of customers with other stakeholders and to capture the broader societal impacts of its activities. The Plan describes aspirational goals to transition to clean energy resources by: ending coal use to generate electricity, reducing carbon emissions by 90 percent from 2005 levels, and meeting customers' needs with 90 percent clean energy resources by 2040. In addition, Michigan has recently launched a customer-focused, multi-year stakeholder initiative called MI Power Grid. MI Power Grid aims to maximize the benefits of the transition to clean, distributed energy resources with a focus on customer engagement, integrating emerging technologies, and optimizing grid performance and investments.

Objectives establish the basis for modernization and describe what CE plans to accomplish through the Roadmap. Through its 2018 EDIIP and Roadmap processes, CE developed a set of overarching objectives which are summarized below:

8 Consumers Energy Clean Energy Plan. 2019.

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- Maintain and optimize the system; rehabilitate, replace, and rebuild existing infrastructure; respond to emergent and customer-driven work; and lay foundation for advanced grid capabilities.
- Transform and modernize the grid by developing new capabilities across the following five customer-driven objectives:
  - **Cyber security, physical security, and safety** – Design the system to ensure the security and safety of customers and employees are maintained and ultimately enhanced.
  - **Reliability** – Improve reliability of the system under normal operating conditions and resiliency under extreme conditions.
  - **Sustainability** – Continue to look for opportunities to explore sustainable options and reduce waste in the system.
  - **Control** – Provide customers with the data, technology, and tools to take greater control over their energy supply and consumption.
  - **System Cost** – Deliver the objectives above at an optimal, long-term system cost for all customers.
- Build for the future to enable a transition to a cleaner, more efficient, and more distributed energy system.
  - **Best in class service to all customers** – Provide customers with safe, reliable, and affordable electric service with best in class customer experience.
  - **Optimize supply and demand** – Optimize supply and demand using a fully integrated strategy for supply, demand-side management, and asset and grid management.
  - **Create the cleanest and most efficient energy system** – Shift to cleaner energy resources, in line with the Clean Energy Plan, and optimize operations to be leaner and lower cost for customers through use of a lean operating system.

It is important that grid modernization plans present a logic that links the proposed technology deployment roadmap back to stated objectives. Described above, CE has articulated a clear set of objectives that convey both scope and timing requirements and subsequently guide its planning process. The Roadmap then creates a cohesive plan to develop the capabilities needed to realize these objectives.

Identifying Capabilities

The next step in the process of developing a roadmap is to identify the capabilities needed to achieve objectives. DOE defines a capability as the ability to execute a specific course of action. A capability can be expertise, processes, tools, and/or technologies that a utility has. Every utility has a wide range of existing capabilities. A grid modernization plan either enhances those existing capabilities or adds new capabilities. Defining the capabilities needed is perhaps the most important component of the roadmap process.

Central to CE's modernization approach is a Grid System Orchestrator (GSO) strategy. The GSO strategy describes a set of future roles and capabilities that will be needed in the functional areas of grid operations, grid planning (short and long-term), grid infrastructure management, distributed energy resource management, and market operations. The GSO functional framework guides the organization and prioritization of CE's grid modernization capabilities.

CE then used a business capability model to provide a framework for determining the specific capabilities that would be needed to enable the GSO strategy. The capability model used, called the Grid Modernization Reference Model, is an experienced-based model focused on the business capabilities needed to effectively operate an electric distribution business. The Reference Model, shown below in *Figure 3*, describes six core utility business functions—grid operations, grid infrastructure, grid management, grid engineering, grid communications, and distribution markets—with each core function further broken down into five sub-functions. While not shown in the diagram, the thirty sub-functions are further broken down into a comprehensive inventory of over 270 business capabilities. *Table 1* illustrates the architectural structure for example business capabilities in grid engineering and grid operations.

The core functions in the Model are closely aligned with the GSO functional framework creating linkage back to CE's overall strategy. While nomenclature may have some differences, the core functions are also in line with the DSPx Next Generation Distribution System Platform and Applications diagram and EPRI's Grid Modernization Playbook.

To enable the GSO, CE also developed a technology-focused architecture, called the Grid Service Platform (GSP), which identifies the systems, applications, data communications, devices, integrations, and services required for its modernization plan. The GSP does an excellent job of describing how systems will fit together in the future, driving solutions based on future business models, and combining on-premises capabilities with cloud-based capabilities. The Reference Model helps to ensure that all potential capabilities are considered; the GSP architecture likewise helps to ensure that the

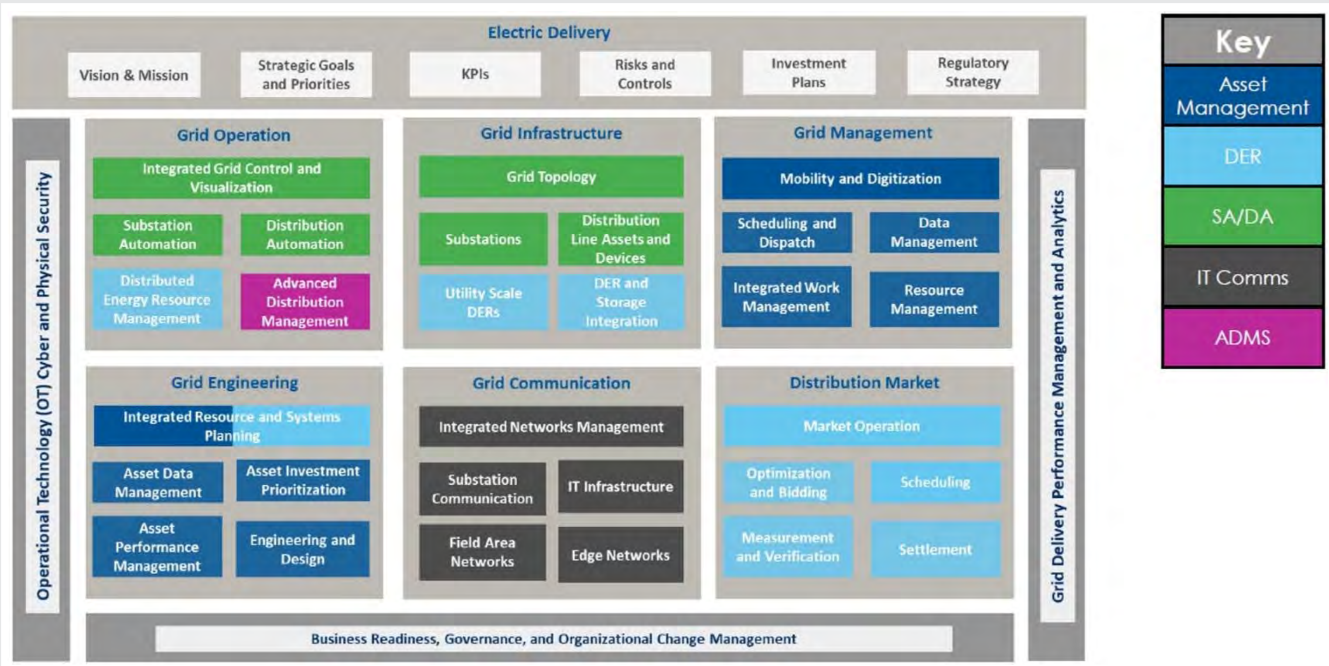

Figure 3. Grid Modernization Reference Model. (Source: Consumers Energy Grid Modernization Roadmap)

Table 1. Core Function, Sub-Function, and Business Capability

Core Function	Sub-function	Business Capability
Engineering	Asset Performance Management	Risk-based asset management
Operation	Distribution Automation	Provide Situational Awareness

associated technology and connecting infrastructure and networks are also identified.

Using the Reference Model, CE leaders and subject matter experts prioritized the 270 business capabilities across several dimensions: expected benefits, addressing identified gaps, business objectives, and timing relative to achieving the future state maturity. The capability prioritization also focused on areas that were expected to have the greatest impact on CE objectives, such as substation and distribution automation, DER integration, ADMS, and distribution asset management. Input was tabulated and prioritized to identify the most critical capabilities and the associated timing and pace for implementation.

Figure 4 is a high-level roadmap timeline illustrating priority capabilities and when they are enabled. The first phase (0–2 years) of the Roadmap focuses on foundational capabilities. Priorities in this first phase are in line with the core components of the DSPx framework. Priorities include areas that are expected to have the greatest impact, such as the ADMS and substation/distribution automation to improve grid situational awareness and control; advance communication network capability from field devices to operations center; developing standardized infrastructure designs that are robust and resilient; and piloting applications to manage utility-owned DER assets. Across the industry, the ADMS is an important technology to deploy early in the process as it can enable a host of decision support capabilities to monitor, control, and optimize the distribution system.

The second phase of the Roadmap (2–5 years) begins to focus on further developing core capabilities in operations, planning, and the supporting systems and the process needed to build out the GSO capability. The third phase (5–10 years) will depend on how market conditions and regulatory processes evolve. The Roadmap presents a measured approach to modernization, starting with core capabilities in the first five years that will provide value regardless of how the next five years evolve.

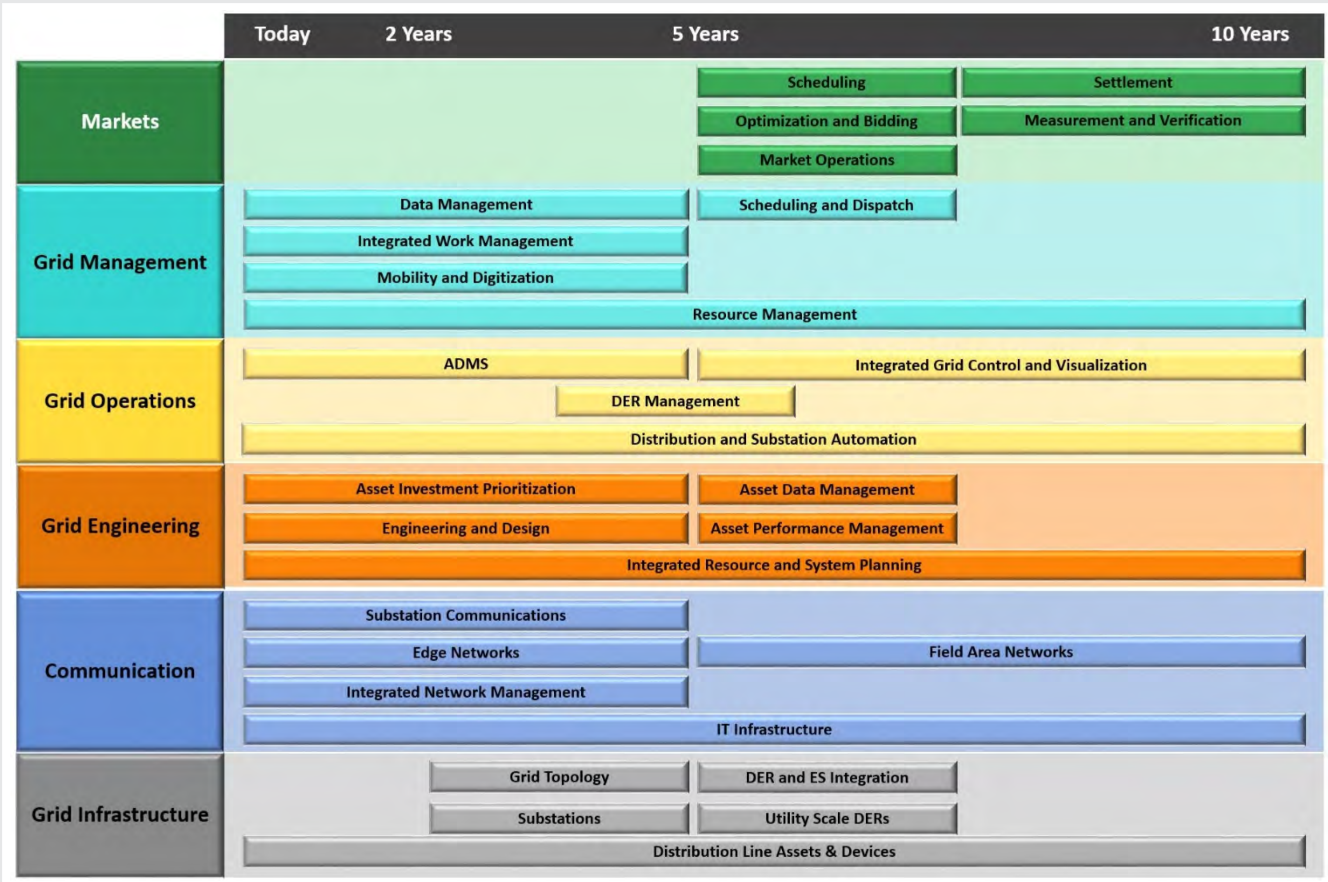

Figure 4. Implementation Timeline for Priority Capabilities

Twenty-two initiatives were then defined representing several categories of investments needed to move CE toward achieving the GSO strategy. The initiatives created traceability between the planned actions and the capabilities enabled, gaps addressed, and the expected benefits. The sequencing, duration, and interdependencies within and between the initiatives resulted in a high-level, temporal roadmap describing how CE intends to integrate the new capabilities into day-to-day operations.

The Roadmap identified cyber security as a cross-cutting capability. Through its modernization efforts, CE is establishing cyber security standards and control framework from the start such that critical capabilities and gaps in operational technology (OT) cyber security are identified and incorporated into the overall design and operation of each project as they are deployed over time.

Similarly, CE has also established distribution data governance and management as cross-cutting initiatives to ensure the appropriate policies, procedures, and controls are in place to manage it. Leading utilities, like CE, are beginning to treat data as a strategic asset and establishing enterprise-wide approaches to data governance and management. Accurate distribution system models will become more critical as DER penetration levels increase, and distribution grids grow increasingly complex. Data will come from across the enterprise; will be used across the enterprise; and will need to be managed across the enterprise with a much higher level of granularity, integrity, and speed.

EPRI's experience with other utility roadmaps and the DOE DSPx materials would indicate that the Reference Model used by CE was comprehensive, thus helping to ensure that all potential business

capabilities were considered in the prioritization process. Further, the priority business capabilities identified by CE leaders and subject matter experts through this process represent those needed to meet its GSO strategy. This practice has become an industry leading approach among utilities that are developing grid modernization plans.

EPRI subject matter experts then reviewed how the prioritized capabilities were being implemented through the Roadmap initiatives. The review encompassed the initiative scope, capabilities enabled, gaps addressed, benefits, and implementation. More than twenty CE and a dozen EPRI subject matter experts participated in this review. Overall observations and recommendations from the initiative reviews are included below, organized around the following initiative categories: strategy, operations, planning, grid infrastructure, work execution, and data management.

Initiative Review

Strategy

The GSO business strategy describes an incremental approach to implementation, focusing first on foundational technologies that are expected to have the greatest impact and value. At the same time, CE plans to conduct field pilots to evaluate key DER integration functions of 3rd party-owned, utility-owned, and customer-owned resources. Field testing will be complimented with a new laboratory capability to provide an integrated platform for evaluating the safety, security, and interoperability of new technologies, without impacting customers or other equipment before deploying on the distribution system. An important consideration may be FERC Order No. 2222 directives in key areas, such as participation models, locational and size limitations, bidding requirements, telemetry, metering requirements, as well as coordination requirements across the important entities. Depending on how (and how quickly) markets and regulatory processes evolve in Michigan will affect how CE will need to transform the GSO capability, but the incremental implementation approach combined with field and laboratory testing to gain experience with key applications is a good practice.

Planning

Integrated system planning is a key concept described in the CE Roadmap, recognizing the need to proactively address changes to the distribution planning process, including near-term and long-term planning considerations and how they are related to the development of grid modernization strategies and subsequent technology implementation plans. With its Integrated System Planning initiative, CE is at the forefront of utilities that are beginning to address these changes, for example Hawaiian Electric and Xcel Energy in Minnesota.

CE is further evolving its interconnection processes to meet aggressive DER and solar energy targets. Among planned activities is the expanded application of hosting capacity analysis[9,10] to CE's low- and high-voltage distribution circuits as more DER enter the queue. In addition, enhancements to PowerClerk are intended to allow the platform to better integrate with the company's existing and future work management processes and support interconnection efficiencies. Together, these activities are expected to improve the associated processes and procedures for both DER applicants (customers and 3rd party developers) as well as internal utility staff.

For all planning processes, system models will need more granularity to address the locational and temporal aspect of the changing generation, storage, and demand resource mix. Processes for collecting and validating system data, integration of applications that contain the system data, and governance processes to maintain data over time will be needed.

CE's engagement with industry collaborative research is one way in which CE is leveraging national research efforts to develop and apply a more integrated approach to distribution system planning. One example is using EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool to more efficiently conduct system hosting capacity assessments.[11]

Operations

At the center of the operations objective is the deployment of a state-of-the-art ADMS to integrate various utility systems and advanced applications into a common software platform over the next 10 years. The ADMS initiative is a continuation of an existing

9 Hosting capacity is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades.

10 *Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity*. EPRI, Palo Alto, CA: 2018. 3002011009.

11 https://www.epri.com/DRIVE

project that seeks to implement, replace, enhance, and/or integrate existing systems and applications. The ADMS is essential to CE's transformation from a traditional dispatching-centric model to a real-time operation and optimization model with unified visibility and control across its grid. The ADMS deployment is a good example of the incremental implementation approach, first starting on a small group of circuits to gain valuable insights and experience with the core ADMS functions, next expanding the scope to include over 800 feeders and associated substations, as well as, additional functionality of the ADMS itself, and looking ahead to add the remaining feeder and substation models to the ADMS, add additional D-SCADA capabilities, integrate other major components, such as the outage management system (OMS), and to start the use of various advanced applications.

EPRI's experience has shown that maintaining GIS data—data quality and accuracy—will be paramount going forward. Also, the volume and complexity of alarms received through the ADMS will typically increase as grid modernization activities add new devices and sensors. Continue to innovate around alarm management and the data the distribution system operator sees to more effectively help the operator take the correct action at the correct time.

The ADMS will additionally provide monitoring, management, and coordination of grid devices as well as utility-, customer- and third party-owned DER, working in tandem with the distributed energy resource management system (DERMS) and the demand response management system (DRMS). CE has identified the necessity to integrate and coordinate the DERMS and DRMS solutions. Developing siloed DERMS and DRMS solutions can lead to duplicative efforts and overlapping system functionalities. To the contrary, the holistic integration of all DER types (including controllable loads/end-use technologies) improves operational efficiency, simplifies performance verification, and enables multiple services. Prior to considering at-scale implementation, however, CE intends to focus initially on smaller pilots to demonstrate DERMS and DRMS use cases and increase CE's knowledge base. For pilots involving behind-the-meter resources, utility pilots have shown that customer acquisition can be a challenge, significantly slowing down execution. Third party aggregators with existing customer portfolios (such as technology vendors) or with prior experience developing customer portfolios, can help accelerate the initial project stages. CE could consider complementing its DERMS and DRMS pilot projects with computer-based simulations, leveraging, for example, the Grid Mod Incubator or EPRI's DER integration test bed environment. The benefits of this approach can be twofold: evaluate vendor products prior to making final product selection and deployment; and explore additional use cases on a range of CE feeders simulated using a distribution modeling software.

The prioritization of use cases is an important step that should be completed prior to vendor selection, to ensure that product functionalities meet all use case requirements. Some use cases may focus on addressing grid challenges created by DER; others may intend to enable new grid programs such as non-wires alternatives (NWA). In any case, grid constraints can always be emulated for pilot purposes. Demonstrating DERMS/DRMS solutions on feeders experiencing actual issues (DER-related constraints, or with opportunities for upgrade deferral) adds significant value to the pilot project. In particular, this approach greatly facilitates the valuation of tangible benefits, and the cost-benefit analysis all together.

Finally, while CE's DERMS and DRMS use cases may primarily focus on distribution applications, it may be advisable to consider whether the recent FERC 2222 order could motivate exploring additional use cases requiring three-way interactions between CE, third party service providers, and Midcontinent Independent System Operator (MISO).

Grid Infrastructure

Within the infrastructure area, CE intends to modernize substation and circuit designs with digital intelligent devices and distributed automation to create the substation and circuit of the future. Additionally, the grid infrastructure includes practices for how distribution assets will be managed and maintained.

The substation modernization initiative aims to increase substation robustness and resilience. The initiative includes the modernization of standards and designs to incorporate and deploy new technologies in power equipment coupled with the deployment of new protection, control, and monitoring devices and communications capabilities. Similarly, distribution circuit modernization also intends to develop robust and standard designs for materials, power equipment, and distribution automation (DA) equipment. The new designs and technologies are essential to optimizing grid performance and supporting grid functions.

EPRI's experience would suggest that the expected increase in inverter based renewable energy resources will present new challenges for protection designs and that a systematic review of protective schemes and relay devices should be included in the plan. Resilient data communication designs, as described in IEC 61850, and cutting-edge data communication technologies (such as process bus) should also be considered to prepare for the potential substation modernization needs in the future.

An additional component of CEs grid infrastructure initiatives is to ensure that the processes, policies, skills, and technology solutions are in place to operate a proactive asset management program for existing and future physical assets—transformers, poles, conductors, meters, reclosers, and regulators. The management of assets requires data from multiple disciplines, such as operations, planning, engineering, supply chain, and finance, to enable informed decisions on the actions to improve and maintain the operation and performance. This includes the capabilities of data capture and integration tied together for the explicit purpose of improving the reliability and availability of physical assets. It includes the concepts of condition monitoring, predictive forecasting, and reliability-centered maintenance and builds on the base of asset data generated from an enterprise asset management solution.

With the Roadmap, CE lays out a comprehensive approach to leveraging data science approaches to improve asset fleet management decisions. CE's engagement with industry collaborative research, such as with EPRI's asset analytics research, is also being leveraged to understand industry-leading practices for: industry accepted codes for consistent recording of information (e.g., problems found in the field); utilizing industry-wide asset performance databases; developing requirements to evaluate various enterprise-wide asset health platforms, and developing asset data models. Collaborative research also provides a conduit for lessons learned from other utilities.

CE has also made cyber security an integral part of this initiative. By addressing cyber security early in the planning process, CE can plan for future security controls that are optimized for emerging grid applications. CE'splans for intelligent electronic devices (IED) management involves both vendor-specific management tools in addition to multi-vendor remote access/IED management solutions. This approach should facilitate automated monitoring and management for a large portion of the individual assets in the roadmap. These management strategies are in line with industry best practices.

Work Execution

Through its work execution initiatives, CE is planning a leading practice optimization of its work force and the technologies that they use. From a field technology perspective, CE is making office applications readily available to the field workforce, both company and contract crews to improve workforce efficiency, to promote access to real-time operational data, to capture data while the job is performed, and to improve safety. This initiative ushers in a new paradigm for the field worker and unlocks a new level of situational awareness and flexibility.

Work execution initiatives are also planned to optimize all functions, including technologies and organizations, related to the scheduling and planning of short- and long-term work both from a worker and equipment standpoint. The technologies and associated processes enable the following capabilities: automation of some of the manual schedule and dispatch tasks, appointment scheduling, resource and work forecasting, and workforce flexibility. The initiative will align company and contract crews with common work management processes, systems, and technologies to provide up-to-date information on the tracking and status of work related to customer requests and storm response. Together, these initiatives will enhance the safety of the workforce by bringing all crews under the same set of standards and work processes, and through the use of a common work and asset management platform while improving overall workforce efficiency.

For the rollout of the work execution initiatives, CE will need to continue to adapt its training to effectively integrate the systems, applications, technologies into its workforce, to stay ahead of the interoperability challenges faced in rolling out new capabilities, to be mindful of the everchanging needs of the modern field worker, to continue to look for opportunities to automate and centralize processes, to layer in advanced cyber and access security practices, and to consider establishing data management practices improve data capture and accuracy.

Data Management

Leading utilities, like CE, are beginning to treat data as a strategic asset and establishing enterprise-wide approaches to data governance and management. Accurate distribution system models will become more critical as DER penetration levels increase and as distribution grids grow increasingly complex. Data will come from across the enterprise; will be used across the enterprise; and will need to be managed across the enterprise with a much higher level of granularity, integrity, and speed.

There are two essential ingredients to an enterprise approach to data management: a solid data management and integration design and

utility business processes and governance that leverage it. Recognizing the importance, CE has articulated a comprehensive vision for what data governance and management would look like and to ensure the appropriate policies, procedures, and controls are in place to manage distribution data. The use of a reference model will be critical for success for these initiatives moving forward; the utility Common Information Model (CIM) is a leading practice. Data architecture development is a critical capability that will need to be addressed early in these initiatives.

Overall Observations and Conclusions

From a broader industry perspective, almost every state in the U.S. has launched regulatory or legislative efforts to begin modern- izing the distribution grid. As a result, many utilities are develop- ing comprehensive plans, in many cases required by a regulatory commission, that lay out strategies for grid modernization over a multi-year time frame. Developing a strategy for grid modernization is complicated. Investments are significant and must be sequenced over several years to achieve both the foundational requirement of safely delivering low-cost, reliable electricity service while also adding new capabilities.

EPRI has worked with electric utilities to develop company-specific strategic roadmaps for more than 15 years. In comparison with other utility roadmaps, and with industry frameworks such as the DOE DSPx and the EPRI Grid Modernization Playbook, CE has taken a more comprehensive approach with its Roadmap. CE is still in the early stages of grid modernization with a primary focus on establishing foundational infrastructure and modernizing core grid technologies, operational and communications systems, and planning tools and processes. In alignment with its corporate objectives, the Roadmap advances those capabilities, while also addressing key supporting capabilities, such as telecommunication and work management, and cross-cutting capabilities such as cyber security and grid data, which are not addressed in detail in the DOE DSPx materials.

The DOE DSPx materials present **four key concepts** to consider when assessing modern-day grid modernization planning processes, The CE Roadmap addresses or expands upon these concepts as described below:

1. Does the plan have **well-articulated objectives** that convey scope and timing requirements that are essential to guide the planning process?

Through its IRP and Roadmap, CE articulated a clear set of objectives that convey both scope and timing requirements that subsequently guide its roadmap planning process ranging from customer experience, to system reliability, and to the clean energy transition. The GSO strategy is central to the modernization approach and provides a progressive and comprehensive functional framework to guide the organization and prioritization of the roadmap. The resulting Roadmap presents a clear logic that links the proposed technology deployment plan and priority back to the GSO strategy and stated objectives. **CE's approach to estab- lishing objectives is considered standard industry practice.**

2. Is grid modernization planning part of a **larger integrated distribution planning process** in which foundational investments are required to enable advanced grid capabilities?

In the DOE context, grid modernization investment planning must be aligned with traditional asset planning and integrated with other planning objectives for resilience and reliability.
Through the 2018 EDIIP, CE established an initial framework for grid modernization and has already made significant progress toward addressing traditional "asset planning" which focuses on proactively addressing safety, code compliance, and basic reli- ability issues over a 5-year horizon. Through the Roadmap, CE is planning to implement a more integrated distribution planning process, whereby asset planning is augmented and expanded to include a longer time horizon (10 years) and more robust appli- cation of advanced grid technologies, alternative circuit designs, and use of DER and microgrids to meet both customer and power system needs. **CE's approach to an integrated planning process is considered leading industry practice.**

3. Has a **systems engineering approach** been used to determine functional and structural needs in line with stated objectives?

Systems engineering is a methodical, disciplined approach that examines key architectural considerations, the timing and pace of deployment, and interdependencies between business pro- cesses and enabling technology options for grid modernization. CE developed a conceptual architecture to identify the systems, applications, data communications, devices, integrations, and services required; how the architecture and technology/applica- tion landscape will evolve over time; and to inform the direction and pace of implementation of the Roadmap. **CE's approach ad- dresses the systems engineering aspect and is considered leading industry practice.**

4. Do technology implementation plans adopt **proportional deployment strategies** that can provide advanced grid capabilities where most needed first and/or initially improve grid function with simpler solutions, followed by more sophisticated approaches later, as needed.

The Roadmap applies this concept by first focusing on foundational capabilities and technologies that are expected to have the greatest impact. As CE moves to the next phase of implementation, it will further develop its core capabilities to build out the GSO capability. The final phase of the 10-year plan will depend on how market conditions and regulatory processes evolve. **CE's proportional development approach is considered standard industry practice.**

The following provides some additional observations for consideration as CE implements its plan over the next 10 years:

Keep an eye on DER: Distributed resources are a major driver for grid modernization efforts nationwide and are also a significant driver for the Roadmap and GSO strategy. DER adoption levels, however, are still relatively low in Michigan. This gives CE time to pursue a more deliberate, incremental approach to evaluating and implementing the tools and process that will be needed.

Focus on workforce is critical: Advancements in operations and planning will also require a closer look at workforce needs. As the distribution system becomes more complex, the roles of distribution engineers and operators will evolve. Utilities across the country are beginning to rethink job functions and define the new skillsets that will be needed in the future to evolve the workforce. Through its workforce related initiatives, CE has anticipated this change and is addressing how field work is managed as well as the digital tools field workers will use to improve efficiency and performance.

Develop data analytic capabilities: Data and analytics are becoming ever more important to inform daily business tasks, long-term investment decision, and continuous improvement. In some cases, utilities are creating a practice around data analytics comprised of data scientists that interface with all areas of utility operations. Data-supported decision-making will become integral to the planning, design, operations, and maintenance of the system to ensure reliability and service standards are met. With the Roadmap, CE is laying out plans to leverage advanced analytic capabilities, for example applying data science to its approach to asset management to improve system reliability and fleet management decisions.

Telecommunications: The industry is experiencing rapid growth and need for connectivity for both operational needs, as well as security. Having a secure, robust, and resilient communication infrastructure will be critical to the future grid performance at all levels. Advancing communication capabilities, from local device automation to central grid operations and control, are an integral, cross-cutting element of the Roadmap across initiatives. As a part of its Roadmap, CE is reviewing its long-term telecommunication strategy, especially regarding the security and resiliency aspects of its networks.

Technology maturity: Considering technology maturity in relation to CE's adoption strategy is a key consideration with respect to selection and timing. CE does a good job of articulating the importance of piloting applications in the first phase and learning-as-you-go approach. The Grid Mod Incubator is a good example of this, providing an integrated platform for evaluating the safety, security, and interoperability of new technologies, without impacting customers or other equipment before deploying on the distribution system.

Industry collaboration: CE's engagement with industry collaborative research, such as with EPRI, is another way in which CE is staying abreast of the technology trends and leveraging national research efforts to develop and apply new technology. CE's participation in EPRI collaborative research to develop and apply a more integrated approach to distribution system planning and advanced hosting capacity methods are two examples.

Note

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI members represent 90% of the electricity generated and delivered in the United States with international participation extending to nearly 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; Dallas, Texas; Lenox, Mass.; and Washington, D.C.

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Appendix F – Catalog of Stakeholder Comments and Company Responses

In its August 20, 2020 Order in Case No. U-20147, the Commission set a final due date for this report of September 30, 2021. The Commission also directed the Company to provide a draft report by August 1, 2021, to allow for stakeholders to provide comments. When this Order was issued, the Company was already planning towards a final filing on June 30, 2021, because a) this aligns with the filing date for the Company's 2021 Integrated Resource Plan, and b) this had been the Commission's due date as established in its September 11, 2019 Order in Case No. U-20147. The Company elected to maintain a filing date of June 30, 2021. In order to provide the two-month comment window envisioned in the August 20, 2020 Order, the Company filed a draft report on April 30, 2021. Two parties provided written comments in the docket on June 1, 2021: a coalition of the Michigan Energy Innovation Business Council ("MEIBC") and Advanced Energy Economy ("AEE"); and a coalition led by the Environmental Law & Policy Center calling itself the "Environmental Groups." The Company has cataloged the major recommendations of those comments in this Appendix F and provided the Company's response to those comments. If the Company has not addressed a particular point made in the comments in this appendix, that does not necessarily indicate Company agreement with that point.

Note: The Association of Businesses Advocating Tariff Equity ("ABATE") also filed comments in the docket on June 23, 2021, but this was too close to the filing date to incorporate responses to those comments.

Comment (page references to Commenter's filings)	Company Response
Topic: Performance-Based Ratemaking	
MEIBC/AEE and the Environmental Groups provided substantial feedback on the performance-based ratemaking proposal in the Company's draft EDIIP.	The Company has reviewed the comments provided by stakeholders and looks forward to continued engagement on this issue. The performance-based ratemaking proposal in this EDIIP represents the Company's initial proposal in accordance with the Commission's Order in Case No. U-20697. The Company expects that a performance-based ratemaking framework will be further refined with additional details in a future electric rate case or other contested proceeding. The Company also expects that further discussions could take place in MI Power Grid workgroups.
Topic: Non-Wires Solutions	
Commenter: MEIBC/AEE	
"Consumers' three-phase approach for pilots extends through 2027, potentially causing the Company to miss NWA opportunities that may be viable in the meantime. We recommend that Consumers explore opportunities to accelerate its NWA timeline… Additionally, Consumers could conduct many portions of Phase 3 in parallel with Phase 2 to accelerate the timetable." (pg. 16)	As noted on page 112 of the final EDIIP, there are no shortcuts for maintaining a reliable grid. As the Company progresses through further pilots, it will learn more to further the process, but the new load at Four Mile illustrates the need for prudence. That said, the phases outlined in Figure 71 represent a "trail map" that may be revised as the Company learns more, not a rigid plan, and the Company will look for opportunities to conduct portions of phases in parallel where practicable.

"New capacity is a relatively small portion of the utility's capital plan, so broadening the scope of use cases for NWAs would allow the utility to find additional opportunities. For example, some utilities in other states also look for opportunities to use NWAs to serve new business when there is enough lead time." (pg. 16)	The NWS approach presented in the EDIIP includes expanding use cases, particularly into using NWS to address reliability and resilience issues, so the Company is already considering how to expand beyond capacity issues. The great majority of New Business program spending is for interconnection of new customers, so it is not clear how NWS would meaningfully impact that.
"In order to truly motivate utilities to engage in NWAs, we recommend that the Commission develop incentives for NWAs. Share savings mechanisms are a good option for NWAs as the align utility earnings with the savings delivered to customers through an NWA project." (pg. 17)	The EDIIP clearly states the Company's position that proper incentives are needed for NWS to be successful. Shared savings is stated as a possibility on page 117.
Commenter: Environmental Groups	
"Continuing to ignore distributed generation is not reasonable, given the increasingly attractive pricing of small-scale solar and the increasing rate of voluntary solar adoption." (pg. 8)	Distributed generation is clearly included in the Company's NWS approach, particularly in Phase 2.
"Consumers should make a concerted effort to work with customers and third-party providers to leverage more market-based opportunities for non-wires solutions." (pg. 8)	In explaining "Evolving Approaches" on page 118, the Company indicates openness to investigating third-party approaches, subject to certain caveats.
"The Company's continuing failure to develop and act on forecasts for reaching capacity limits makes substantial use of non-wires solutions involving voluntary customer actions nearly impractical." (pg. 8)	The issue of forecasting secular growth of existing load vs. new load is discussed on page 112. As discussed on page 117, the Company's look-ahead in support of IRP DAUD batteries found 23 potential LVD substations over 20 years, out of a population of nearly 1,100, indicating there is not a huge population of future capacity issues that are being ignored by the Company.
"A 5-year distribution plan should identify the substations and any other distribution system components that are likely to reach capacity limits within 5 years, and preferably 10 years ahead." (pg. 8)	The Company indicated in stakeholder meetings that the purpose of the EDIIP was not to provide comprehensive lists of specific projects, which are provided in electric rate cases. That said, the Company did provide the constituent parties of the Environmental Groups with the DAUD battery substation analysis in discovery in Case No. U-20963, and thus the requested information has already been shared.
Topic: Integrated Resource Plan Alignment	
Commenter: MEIBC	
"We recommend that Consumers also include a [load forecasting] assessment similar to that included for EVs, out to 2040, for building electrification." (pg. 12)	This issue is properly addressed through the Company's 2021 IRP filing.

"It is important to look beyond the expected contributions to load to consider how assumptions about EVs and building electrification will impact hosting capacity analysis, the use of NWAs to most cost-effectively meet the needs of customers, what types of supply resources are needed, and what investments are needed in the distribution system to best take advantage of these resources." (pg. 13)	Some of these issues, like near-to-medium term NWS and HCA, are discussed in other parts of the report. The Company's focus on HCA has been to meet the phase-in requirements established by the Commission. In general, the issues raised by MEIBC in this paragraph will be the focus of further developments toward integrated planning through the MI Power Grid process.
"…with a simplified approach that applies a 2% annual load growth to plan projects 2-years in advance. We note that advanced analytics can generate previously unobtainable insights from granular AMI data, such as voltage, current, and power." (pg. 13)	The analytical tools used by the Company in LVD Lines Capacity planning and other Capacity sub-programs are discussed in the introduction to the section on the Capacity Program in the report, with further details in specific sub-programs. It is not a simplified approach; the 2% annual load growth approach is no longer used, and page 103 refers to it as a historical practice.
"Modeling [customer-sited DG and storage] as a load modifier fails to take into account to additional benefits to the distribution system of distribution-connected solar and seems to be a lost opportunity that could be gained through the development of the IRP and EDIIP at the same time. With the assumption that large-scale solar is lower cost, there is essentially no opportunity to model smaller-scale solar as a resource in the IRP except perhaps in the Advanced Technology scenario." (pg. 13)	Issues related to IRP modeling are properly addressed through the Company's 2021 IRP filing. The purpose of this particular section of the EDIIP is to acknowledge what IRP modeling has been done and discuss how distribution planning will accommodate IRP outputs.
"Consumers should be working now to develop a more detailed approach to storage that includes consideration of other values. Also, selecting a 2 MW size for batteries considered for the DAUD seems large and would likely miss a lot of potential…" (pg. 14)	This issue related to IRP modeling is properly addressed through the Company's 2021 IRP filing.
"The EDIIP should go further to also consider how to use EVs as grid resources, first starting with EVs as a large, controllable load and then as supply in the future when greater vehicle-to-grid operations are possible." (pg. 15)	Because EV penetration is forecast to remain relatively low in the five-year period covered by this EDIIP, the Company expects to address this issue in more detail in future proceedings, and notes that this topic has been a focus in the New Technologies and Business Models MI Power Grid workgroup.
Commenter: Environmental Groups	
"To the extent that the Company estimates the cost of an NWA solution to meet distribution capacity needs (rather than soliciting third-party proposals), its current approach improperly inflates the "true" cost of an NWA solution by	This issue appears largely related to IRP modeling and would properly be addressed through the Company's 2021 IRP filing. The purpose of this particular section of the EDIIP is to acknowledge what IRP modeling has been done and discuss how

ignoring other values that market-provided solutions would provide (beyond solving a distribution grid need), and therefore ignoring the revenue streams that those solutions would likely receive (e.g. energy sales in MISO)… Considering this range of value [for DERs, DG, storage] would help ensure that the Company is evaluating solutions in its planning process on a fair footing." (pg. 10) "Overestimating the costs [of DG] will lead to underforecasting [of DG penetration]." (pg. 12)	distribution planning will accommodate IRP outputs.
"The Company's draft EDIIP fails to adequately examine longer-term-future load…. It is disappointing that the Company did not develop scenarios based on substantial adoption of [EVs and solar DG] and assess whether there should be near-future changes in the Company's engineering standards in anticipation of those scenarios." (pg. 11)	The Company's load growth scenarios are an IRP issue.
Topic: Grid Modernization Roadmap	
Commenter: MEIBC/AEE	
"AEE/Michigan EIBC believe that it is critical that Consumers design their GSP to allow for third-party aggregation and participation of [third-party and customer-owned DER]." "More generally, AEE/Michigan EIBC support the development of a robust market for third-party products and services to serve customers and to also provide valuable services to utilities." "Therefore, we request that Consumers clarify in their EDIIP how third parties will be able to interact with the GSP and fully engage in market opportunities, whether with their own resources, or on behalf of customers." (pg. 10)	The GSP, as presented in this EDIIP, is envisioned as a set of technologies that taken together will allow the Company to manage the distribution system in a future with higher DER penetration, regardless of DER ownership structure, especially as the final outcomes of FERC Orders No. 841 and No. 2222 are still to be determined. The Company has an obligation to its customers to provide reliable service, and as DER penetration increases this will require integrated utility control, management, ownership, and maintenance of distribution assets. Putting reliable electric service at the mercy of market price signals for third-party distribution assets would put Michigan at risk of future situations like that experienced in Texas in early 2021. The Company's various proposals in other proceedings relating to EWR, DR, behind-the-meter storage, etc. indicate that the Company does expect customer-owned and third-party resources to play a role in the grid, but a utility-coordinated and planned system is a more effective means of achieving this than by creating a distribution market.

	It should be noted that the Grid Modernization Roadmap, as a whole, encompasses more than just DER integration.
Commenter: Environmental Groups	
"The EDIIP does not make it clear how the Company's proposed grid modernization investments will actually prepare the grid to integrate *higher levels* of distributed energy resources, nor does it make clear how the Company's proposed grid modernization strategy will *optimize* those distributed energy resources (i.e. the location, time of dispatch, or configuration of those resources) to promote broader energy system decarbonization." (pg. 5)	The Company believes that the extensive information provided in the EDIIP, including the EPRI report in the appendix, which includes its own synopsis of the Grid Modernization Roadmap, does provide a comprehensive overview of how the Company will address these issues. Providing far more granular technical detail about this, along with every other investment covered in the EDIIP, would have created a significantly longer document, not one useful for presenting an overall five-year investment plan.
"The draft EDIIP does not *describe* the Grid Orchestrator role in any detail. Importantly, it is unclear to what extent any of Consumers' proposed distribution system investments will enable the orchestrator function it envisions." (pg. 6)	See comment above. Additionally, the EDIIP largely does not use the term "orchestrator," although EPRI uses the term in its report in Appendix E. The grid system orchestrator is a business capability that the Company is building to manage a grid with increased DER penetration, similar to how the Company has built capabilities to manage customer DR. The technologies in the GSP are meant to deliver this grid system orchestrator business capability.
"An <u>open</u> grid services platform, not limited or prioritized for the Company's own programs, would go a long way towards ensuring that Consumers effectively and efficiently operates its system."	See earlier comment in response to MEIBC/AEE – the Company does envision a role for third-party and customer-owned resources, albeit not through a hypothesized distribution market.
Topic: Grid Modernization Benefit-Cost Analysis Framework	
Commenter: MEIBC/AEE	
"We recommend that Consumers review this comprehensive guide on BCA for DERs and adopt appropriate elements to more fully capture the range of costs and benefits that will be associated with its grid modernization efforts." (pg. 11)	The Company's Grid Modernization Roadmap, and the associated BCA framework, is broader in scope than just a vehicle for DER integration, and the primary purpose of the Grid Services Platform is to enable grid management capabilities, so the BCA framework is designed with this in mind. That said, the Commission and Commission Staff have expressed openness to further stakeholder discussions on BCA specifics after utilities' 2021 distribution plans are filed, and additional refinements could be discussed at that time.

<table>
<tr><th colspan="2">Commenter: Environmental Groups</th></tr>
<tr><td>“The EDIIP should include the complete costs/revenue requirements associated with its grid modernization expenditures, as well as the overall benefit/cost ratio for the Company’s planned investments.” Environmental Groups noted that this should be in spreadsheet form. (pg. 5)</td><td>As discussed in the report, the purpose of the BCA framework as currently established is not to provide a complete BCA of all planned investments, but to provide a tool that will increasingly be integrated into distribution planning. The Company notes that members of the Environmental Groups requested this detailed information in electric rate case discovery in Case No. U-20963, which the Company provided.</td></tr>
<tr><th colspan="2">Topic: Granularity of Data</th></tr>
<tr><th colspan="2">Commenter: Environmental Groups</th></tr>
<tr><td>“However, in order for de-averaged data to be more useful for the Commission and for interested stakeholders, the Company should provide reliability data in an Excel spreadsheet that accompanies the distribution plan and should maintain an interactive online map that displays reliability data.”

“Environmental Groups therefore strongly recommend that the Company further disaggregate circuit-level data to small geographies based on customer address such as census tract of 9-digit zip code zones.” (pg. 3)</td><td>The granularity of reliability data provided in this EDIIP is in line with the Commission’s direction. Utilities proposed a set of “standardized components” for distribution plans, including level of reliability data, to all stakeholders in October 2019, and this proposal did not meet with opposition. It was subsequently adopted by MPSC Staff in their April 1, 2020, report and then by the Commission in its August 20, 2020 Order. The level of detail in this EDIIP exceeds what was required.</td></tr>
<tr><td>“Further, Consumers should provide more detail on the ‘corrective action plans’ and ‘targeted investments’ it intends to undertake in order to address poor-performing circuits and the costs of those plans and investments.” (pg. 4)</td><td>As stated by the Company in its February 16, 2021 stakeholder outreach meeting, the purpose of this EDIIP is not to provide a comprehensive list of projects, but instead to set strategic parameters and lay out necessary spending on a programmatic basis. The Company provides considerable information about specific targeted investments in its electric rate cases.</td></tr>
<tr><th colspan="2">Topic: Filing Schedule</th></tr>
<tr><th colspan="2">Commenter: Environmental Groups</th></tr>
<tr><td>“The EDIIP is a significant and detailed (over 300 page) document that not only charts the Company’s distribution strategy, but also directly implicates the Company’s (and Michigan’s) broader energy policy goals. As such, the EDIIP deserves and required long than 30 days for comprehensive review, and longer than 30 days to incorporate stakeholder feedback. As such, we recommend that Consumers incorporate stakeholder feedback, seek additional meetings with stakeholders, and file its final EDIIP by September 30 as the Commission had originally</td><td>The Company’s filing of the initial draft EDIIP on April 30, 2021 and filing of the final EDIIP on June 30, 2021, maintains the two-month period established by the Commission in its August 20, 2020 Order. Were the final filing date to be September 30, 2021, then the initial draft would not have been provided until August 1 under the terms of that Order. The Company communicated its filing schedule to all parties months prior to filing and no parties raised any objection, and the scope of the 2018 EDIIP (itself 307 pages long) would have indicated to all parties that this</td></tr>
</table>

recommended, rather than filing its plan by June 30 in order to coincide with its IRP filing." (pg. 1)	document would be similar in length. The EDIIP is an informational filing, not a contested case. Any investment or other decisions based on the content of the EDIIP will be litigated in electric rate cases or other contested proceedings.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.	))))))	Case No. U-20147

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on June 30, 2021, she served an electronic copy of **Consumers Energy Company's Final Electric Distribution Infrastructure Investment Plan ("EDIIP") 2021-25** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 30th day of June, 2021.

Jennifer Joy Yocum

Jennifer Joy Yocum, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 12/17/24
Acting in the County of Jackson

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