

Founded in 1852  
by Sidney Davy Miller

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January 31, 2025

Ms. Lisa Felice  
Executive Secretary  
Michigan Public Service Commission  
7109 West Saginaw Highway  
Lansing MI 48917

Re: Upper Peninsula Power Company  
Case No. U-20147

Dear Ms. Felice :

Attached for electronic filing in the above-referenced case is Upper Peninsula Power  
Company's Distribution Plan.

Should you have any questions, please advise.

Sincerely,

Miller, Canfield, Paddock and Stone, P.L.C.

By: \_\_\_\_\_  
Paul M. Collins

Enclosure  
PMC/vs  
cc w/enc: Eric Stocking



# **2025 Distribution Investment & Maintenance Plan**

Upper Peninsula Power Company  
January 31, 2025



<b>EXECUTIVE SUMMARY .....</b>	<b>3</b>
<b>BACKGROUND .....</b>	<b>5</b>
MICHIGAN’S UPPER PENINSULA – SYSTEM TOPOGRAPHY.....	5
UPPCO’S SERVICE TERRITORY.....	8
DISTRIBUTION SYSTEM .....	13
<i>Overhead System</i> .....	14
<i>Underground System</i> .....	14
<b>DISTRIBUTION PLAN INPUTS, METHODOLOGY &amp; DECISION CRITERION .....</b>	<b>16</b>
OVERVIEW OF RELIABILITY METRICS.....	16
LOAD FORECASTING.....	21
DISTRIBUTED ENERGY RESOURCES .....	21
ELECTRIFICATION.....	22
<i>Electric Vehicles</i> .....	22
<i>Heat Pumps, Air-Source</i> .....	26
INTEGRATED RESOURCE PLANNING .....	28
PRIORITIZATION METHODOLOGY .....	28
<i>Project Classification</i> .....	28
<i>Decision Criterion</i> .....	29
<i>IEEE Indices</i> .....	29
<i>Worst Feeder Ranking</i> .....	29
<i>Multiple Device Operations</i> .....	30
<i>Field Crew Experience</i> .....	30
<i>Inspections</i> .....	30
<i>Project Costing</i> .....	30
PERFORMANCE MONITORING / PROJECT ADJUSTMENTS .....	32
<i>Performance Monitoring</i> .....	32
<i>Project Adjustment</i> .....	32
<b>UPPCO FIVE-YEAR DISTRIBUTION PLAN .....</b>	<b>34</b>
OVERVIEW .....	34
STORM HARDENING.....	35
<i>Line Clearance/Vegetation Management</i> .....	35
<i>Overhead Inspection Program</i> .....	39
<i>Underground Inspection Program</i> .....	39
<i>Strategic Undergrounding</i> .....	41
<i>Selection</i> .....	41
<i>Outage Reduction</i> .....	41
<i>Effective and Prudent Capital Investment</i> .....	42
<i>Intrinsic Value &amp; Customer Savings</i> .....	43
<i>Improved Safety</i> .....	43
<i>Overall Costs</i> .....	44
<i>Overhead Line Hardening</i> .....	44
<i>Effective Shared Facilities Program</i> .....	44
<i>Enhanced Restoration Process</i> .....	45
<i>Optimize Technology</i> .....	45
ASSET RENEWALS.....	46
<i>Asset renewals are another cornerstone of UPPCO’s distribution reliability plan.</i> .....	46
<i>Overhead</i> .....	46
<i>Underground Replacement Plan</i> .....	50



<i>Transformer Replacement Program</i> .....	51
SUBSTATION INSPECTION, MAINTENANCE, AND PROJECT PLANNING .....	52
<i>Periodic Inspection Program</i> .....	53
<i>Maintenance Processes</i> .....	53
<i>Substation Standards</i> .....	54
<i>Asset Renewal Determination</i> .....	54
RISK MITIGATION .....	58
<i>Employee &amp; Public Safety</i> .....	58
<i>Storm Plan and Storm Management</i> .....	60
<i>Inspections</i> .....	60
GRID MODERNIZATION (NEW TECHNOLOGIES / IT & OT SYSTEMS / DATA ACQUISITION & ANALYSIS).....	61
<i>Geographic Information System</i> .....	61
<i>Outage Management System</i> .....	62
<i>Automated Meter Infrastructure</i> .....	63
<i>Supervisory Control and Data Acquisition</i> .....	64
<i>Overcurrent Protection Planning</i> .....	65
<i>Voltage Regulators</i> .....	65
<i>Distribution Automation</i> .....	66
<i>Faulted Circuit Interrupters</i> .....	66
<i>Potential Future Technological Innovations</i> .....	66
<i>Non-Wires Alternatives / Solutions</i> .....	68
<i>Distributed Generation (“DG”) Interconnections</i> .....	71
<i>Financial Model/Projections (Summary Level Business Drivers)</i> .....	75
<i>SHARP Projects &amp; Justifications</i> .....	77
<b>LIST OF APPENDICES</b> .....	<b>79</b>



## Executive Summary

Upper Peninsula Power Company (“UPPCO”, or the “Company”) is prepared to lead the Upper Peninsula of Michigan (“UP”) to a clean, connected, and sustainable future where serving our communities remains at the center of what we do. We accomplish this goal by investing responsibly in safety, reliability, and people, all while maintaining a sharp focus on several principles which UPPCO believes should be at the forefront of its decision-making:

**Safety** – UPPCO views the safety of its employees and the communities it serves as a non-negotiable principle and strives to continuously improve safety performance across all aspects of the business.

**Customer** – The Company is committed to providing safe, reliable and affordable electric service to its customers, with a focus on ensuring that each customers’ interactions with UPPCO are exceptional.

**Stewardship** – UPPCO has owned and operated renewable energy resources in Michigan for nearly a century. Today, the Company takes a multi-faceted approach to the principle of stewardship, through responsible investment in required infrastructure and prudent management of the natural resources that are abundant throughout UPPCO’s service territory.

UPPCO, like other electric utilities, energy providers, and communications companies, provides essential service and critical infrastructure to support the economy, health, and general welfare in the United States. Governmental entities, regulators, businesses, and residents are all calling for better electric reliability and a more resilient grid. Concerns of climate change, which have been linked to causing more extreme and more frequent weather-related events have placed electric utility companies and the reliability of their electric systems on the front pages of newspapers, and at center-stage of local community meetings. UPPCO’s planning processes are intended to address these concerns and will improve the reliability and resiliency of its distribution system over time.

On March 24, 2023, the Michigan Public Service Commission (“MPSC” or the “Commission”) issued an order approving a settlement in Case No. U-21286. Paragraph 9(h) of the approved settlement agreement states that “UPPCO shall work with Staff to develop and file a distribution investment and maintenance plan, no later than January 31, 2025.” The settlement agreement further stipulates that this distribution investment and maintenance plan must be consistent with the Commission’s September 8, 2022, order in Case No. U-20147. UPPCO represents that this document satisfies the Company’s requirements related to a distribution investment and maintenance plan, pursuant to the Commission’s directive in Case U-21286.

UPPCO’s distribution investment and maintenance plan (the “Distribution Plan” or the “Plan”) has its own set of goals which fit neatly into UPPCO’s Strategic Themes:

- Provide safe, reliable and resilient electric service to all customers.
- Continually improve the customer experience.
- Decrease any safety related risks to the public.
- Maintain adequate service voltage within established limits.
- Reduce the frequency and duration of outages.



- Meet all municipal and permitting obligations.
- Make cost-conscious and data-driven decisions in the performance of such activities.

UPPCO's purpose is to continue to provide safe, reliable, and resilient electric service to its customers at reasonable rates. This service is fully accessible to customers wherever and whenever it is desired for a host of uses. This service will not only serve traditional loads, but also new, high demand loads such as electric vehicle DC fast-chargers, and distributed energy resources (DERs) such as solar panels, wind generation, and energy storage-batteries. Customers expect high quality electric service, meaning that utilities must maintain steady, consistent voltage, with minimal outages, while simultaneously accounting for fluctuating loads. Further, utilities must also consider the increasing prevalence of generation sources that are utilizing the same distribution lines and intermittently injecting energy back into the system.

In light of these challenges, UPPCO must create a grid platform to meet these ever-changing needs today and into the future. It must be flexible enough to easily adjust to changing load and energy requirements, and also be resilient in its ability to rebound from both weather-related, catastrophic events, as well as human-caused events such as vehicle accidents.

Safety is paramount at UPPCO, and safety considerations are integrated into all aspects of daily operations to provide a safe work environment for employees, as well as for the general public. UPPCO provides safe electric service by constructing to company standards, industry codes and industry best practices, and through performance of inspections of the overhead and underground distribution systems. Additionally, as communication companies request attachments to UPPCO facilities, this affords another opportunity to confirm the adequacy of the system with respect to National Electric Safety Code ("NESC") pole strength and clearance requirements, or correct inadequacies, as necessary.

UPPCO achieves system reliability improvements by identifying and prioritizing impactful capital expenditure ("CapEx") investment projects. Using the funds approved for distribution-related CapEx in its most recent general rate case, UPPCO continues to enhance system reliability and performance through the creation of additional switching corridors, continuing a cyclic vegetation management program, and well-timed asset renewals.

UPPCO also plans to maintain system reliability and performance by continuing to work closely with American Transmission Company ("ATC"). ATC provides network transmission service to UPPCO's substations. ATC has invested millions of dollars into the grid in the UP, and UPPCO supports its efforts to improve the transmission system serving UPPCO customers and other electric utility customers throughout the Upper Peninsula. Although UPPCO does not own any transmission facilities, the Company influences ATC's transmission maintenance and CapEx projects to improve grid performance in the rural areas of the UP.

In this filing, UPPCO's is sharing its well-established distribution planning process that it uses as a comprehensive guide for the Company's distribution planning and maintenance activities. The above-average performance of UPPCO's distribution systems, when compared to other comparable utility systems, is a direct result of UPPCO's well-established planning, prioritization, and maintenance practices, many of which have been thoroughly explained in prior regulatory proceedings.

UPPCO believes the primary path to achieving continual improvement in reliability metrics lies in continued responsible investment in distribution infrastructure. This is done by allocating the Company's



finite CapEx towards projects that align with the Plan's prioritization parameters and uninterrupted systematic maintenance of the distribution system components.

## Background

### Michigan's Upper Peninsula – System Topography

UPPCO's service territory is located in Michigan's Upper Peninsula, which is home to approximately 300,000 people of Michigan's 10.3 million people.

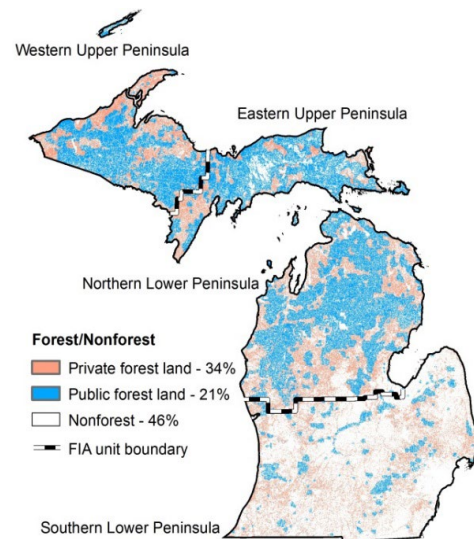
The Upper Peninsula is heavily wooded and is about as wide east to west as the Lower Peninsula is north to south. However, the UP only makes up about 30% of Michigan's total land area. The UP's industry has historically been based on copper and iron mining and the timber industry.

Much of the UP is federal or state forest land. According to a 2017 USDA Forest Service Report, "the Upper Peninsula accounts for only 29% of Michigan's area but has 45% of the forests."

The heavily forested nature of the UP leads to specific challenges when seeking to maintain a distribution system. Heavily wooded, non-urban, areas require more line clearance activities per mile due to the density of tree coverage. These areas are also more difficult to patrol and there is an increased likelihood for multiple tree-caused outages on the same circuit during storms.

The amount of snow is another factor that impacts UPPCO's distribution maintenance and planning processes. With the exception of UPPCO's more southern districts, Iron River and Delta, UPPCO's service area receives 150-300 inches of annual snowfall, much of which is Lake Superior lake-effect snow. Lake Superior does not freeze over quickly during the winter season, causing lake-effect snow to persist through much of the winter.

Large amounts of snow are disruptive to UPPCO's operations. Snow makes access to the lines and patrolling much more difficult. Snowfall around the freezing point of 32° creates wet, heavy snow that, when combined with high winds, results in snow and ice accumulation on overhead conductors that create sag and galloping conditions. Heavy snow also tends to accumulate on off-right-of-way evergreen trees, which bend into the overhead distribution system and create outages. The photo below demonstrates how wet snow accumulation causes trees to bend and fall over.



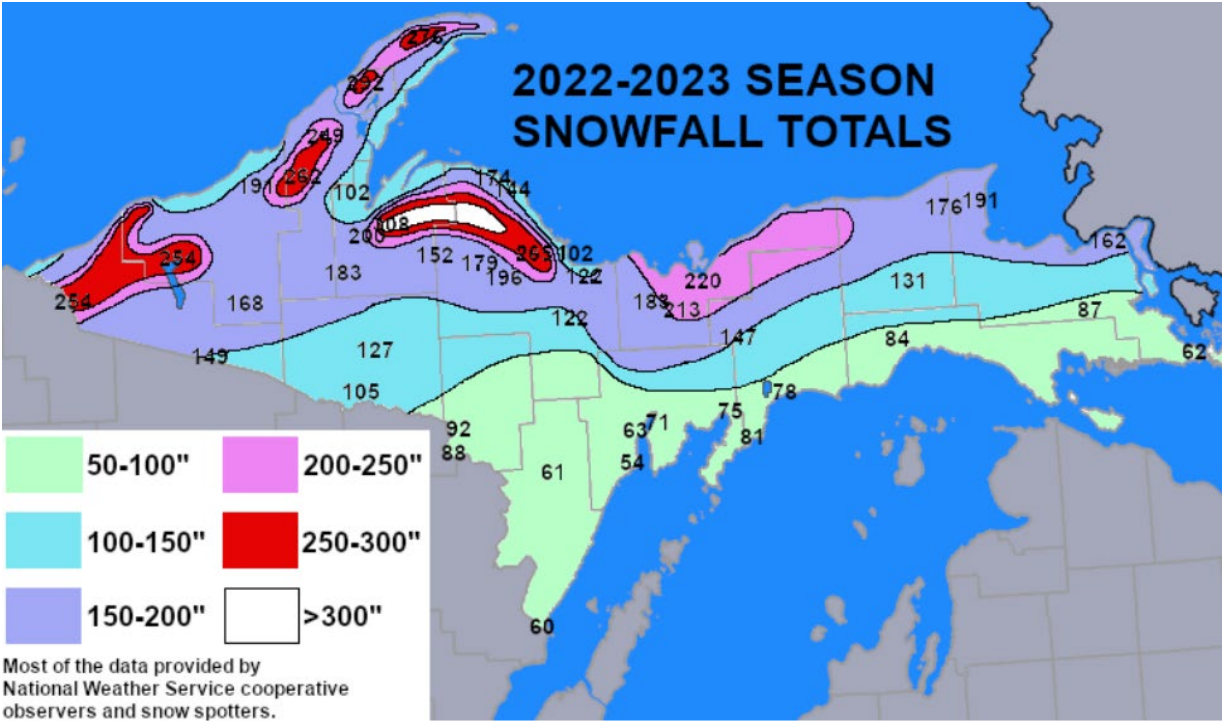
*Forested land in Michigan's Upper and Lower Peninsulas. | Source: Pugh, Scott A. 2018. Forests of Michigan, 2017. Resource Update FS-153. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northern Research Station. 4 p. <https://doi.org/10.2737/FS-RU-153>.*



*Effect of wet, heavy snow on trees and electric lines*

Due to the localized nature of lake effect snowfall, several areas of the same circuits may be affected by multiple tree-related outages, making patrol, outage cause identification, and restoration more complex for line crews. Occasionally, these conditions necessitate the use of specialized equipment, such as tracked buckets and diggers, snowmobiles, ATVs, and tracked snow machines to transport people and material, to identify the outage cause and restore power. The picture at right indicates some of the rugged cross-country terrain crews must patrol during severe weather conditions.





Seasonal Snowfall in the UP | Source: <https://www.weather.gov/mqt/seasonsnowfallmaps/>

Additionally, snowy or icy conditions result in more vehicle-pole collision accidents as shown in the picture below.

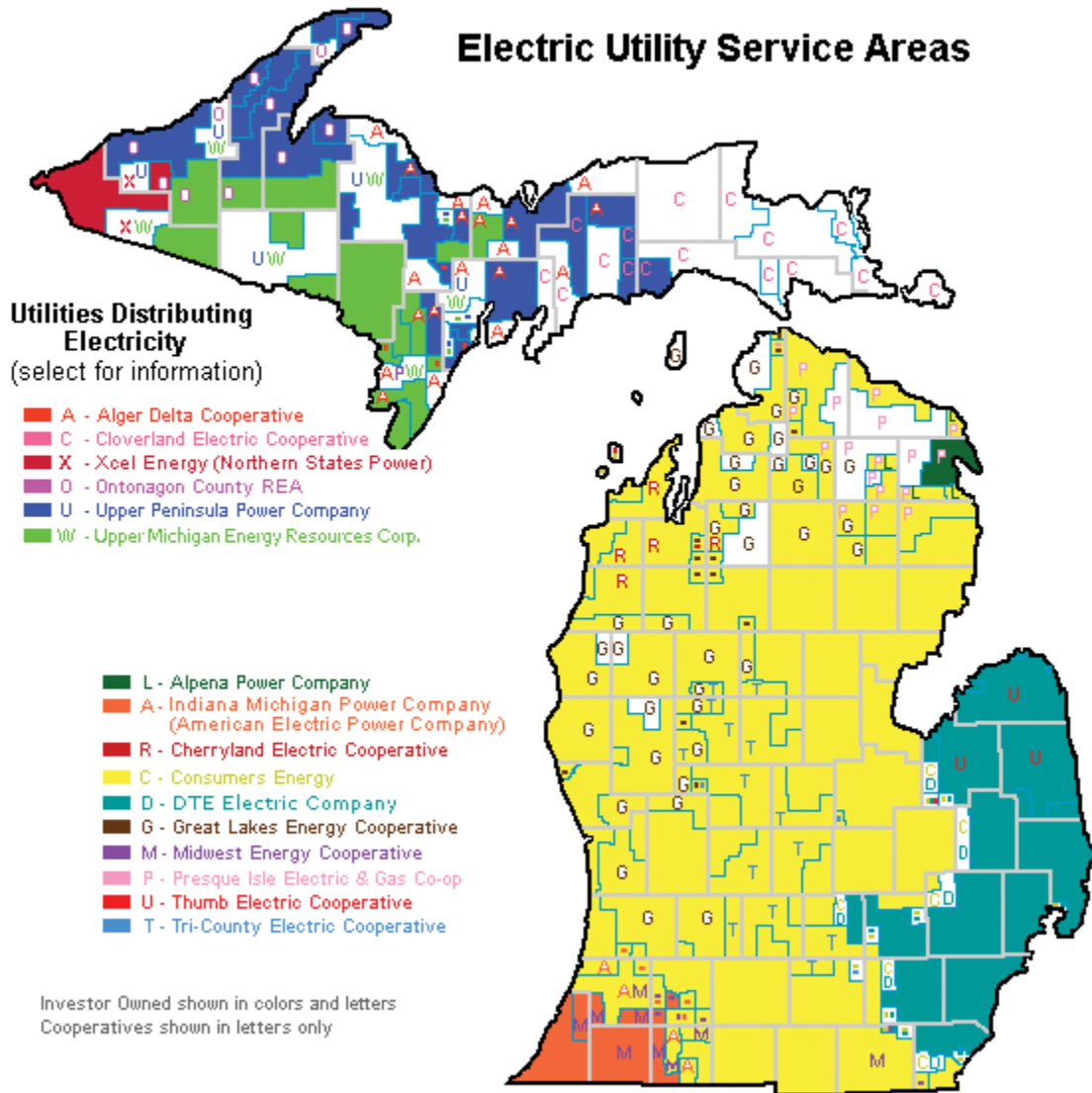


Vehicle-pole accident

## UPPCO's Service Territory

UPPCO serves approximately 59,000 metered locations in Michigan's Upper Peninsula with a service territory of approximately 4,500 square miles in 10 of the 15 Upper Peninsula counties.

Residents and businesses in Michigan's UP are served by several investor-owned utilities and cooperatives/REAs. Additionally, several villages and cities are served by municipal electric systems, which are not indicated on the map below as they are not state regulated.



*Electric Utility Service Areas of Michigan* | Source:  
<https://www.michigan.gov/mpsc/consumer/electricity/electric-utility-service-area-map>



UPPCO’s service territory includes portions of 10 of the UP’s 15 counties: Alger, Baraga, Delta, Houghton, Iron, Keweenaw, Marquette, Menominee, Ontonagon, and Schoolcraft. UPPCO’s service territory is split into six geographic districts, and each is served by a service center in a location that gives each district its name. There are three districts in the western division – Houghton, Iron River, and Ontonagon – and three districts in the eastern division – Ishpeming, Munising, and Delta (Escanaba area).

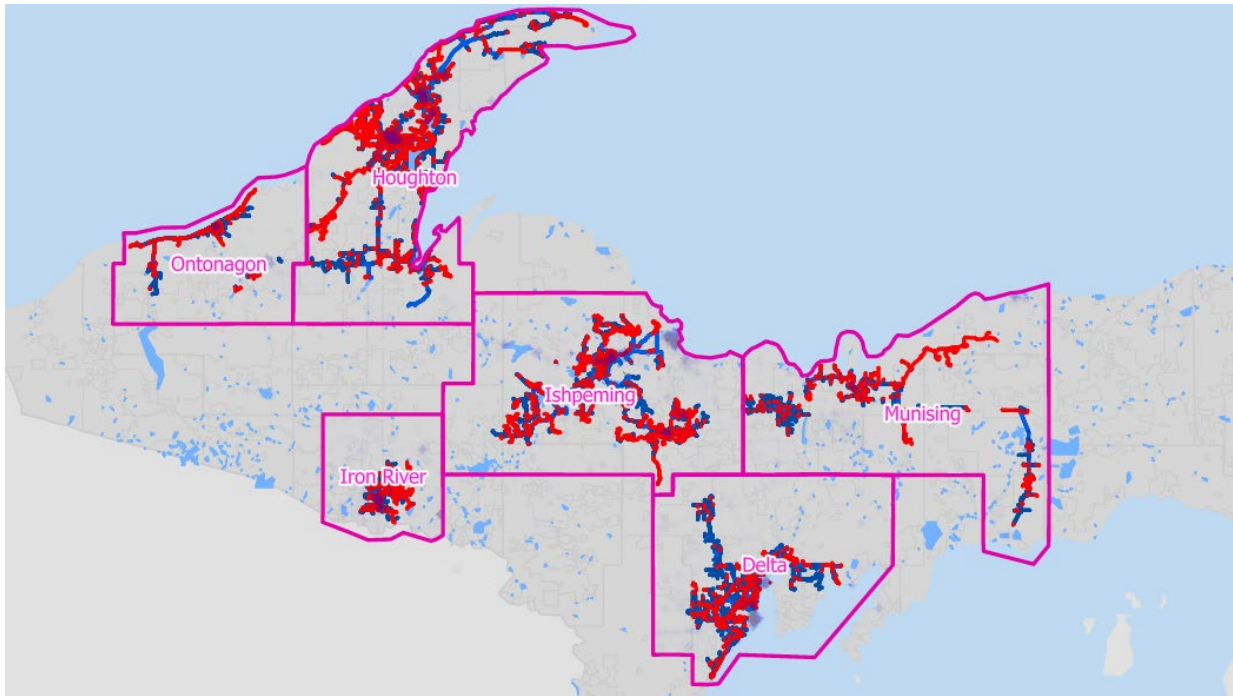
The table below shows the approximate number of meters and circuit miles in each district based on GIS data from January 2024. Note that this data is a snapshot in time since nearly every day new customers are added to the system or other customers close their accounts for various reasons, such as relocation.

<u>District # - Area</u>	<u>Meters</u>	<u>Circuit Miles</u>
21 - Houghton	24,299	1,594
24 - Iron River	4,241	300
25 - Ontonagon	2,973	230
<b>West Division Total</b>	<b>31,513</b>	<b>2,124</b>
26 - Ishpeming	14,321	1,118
27 - Munising	5,585	546
28 - Delta	7,514	786
<b>East Division Total</b>	<b>27,420</b>	<b>2,450</b>
<b>UPPCO Total</b>	<b>58,933</b>	<b>4,574</b>

While, UPPCO’s service territory primarily consists of rural areas, UPPCO’s “urban” service territory consists of the cities of Caspian, Gaastra, Houghton, Hancock, Iron River, Ishpeming, Munising, and the villages of Ahmeek, Calumet, Chatham, Copper City, Lake Linden, Laurium, Ontonagon, and South Range.

Urban locations are generally easier to serve because the density of customers in a smaller geographic area requires less circuit miles to serve and therefore there is better reliability compared to rural locations where long distribution lines are routed through typically heavily wooded areas that are often not along road rights-of-way. Rural areas are also further away from UPPCO service centers, more difficult to access and patrol, and require significantly higher levels of line clearance work.

UPPCO’s feeders typically serve a combination of urban and rural areas with the majority of feeders originating from substations located in more urban areas and then sprawling out into the more rural areas to serve customers at the extremities of UPPCO’s service territory.



UPPCO distribution system in GIS | Red = Underground, Blue = Overhead  
 (Note, significant overlap exists between the overhead and underground systems at this zoom level)

Areas shown within UPPCO’s service territories without UPPCO distribution lines are those served by other electric utilities. There are numerous other electric service providers operating in close proximity to UPPCO’s service territory. Within UPPCO’s service territory, UPPCO does not serve customers within the city or village limits of Baraga, Crystal Falls, Escanaba, Gladstone, L’Anse, or Marquette, which are all served by municipal electric departments. UPPCO also does not serve the Houghton County Airport/Industrial Park, or other areas served by the Ontonagon REA.

Some of the other co-ops and utilities interspersed within or adjacent to UPPCO’s service territory, include Alger Delta, Cloverland, UMERC, and Xcel.



Figure 1 | MECA member utilities in the UP



Figure 2 | Cloverland Electric Cooperative Service Territory



Figure 1 above indicates MECA member utilities in the UP. The number one (1) indicates Alger Delta Cooperative and number six (6) indicates Ontonagon County REA service territories. Figure 2 above indicates Cloverland Electric Cooperative’s service territory.

Figure 3, below left, indicates Upper Michigan Energy Resource Corporation’s (“UMERC”) service territory. The map on the right below indicates MBLP’s service territory, which extends beyond city limits into the neighboring townships of Marquette, Chocolay, and Sands.

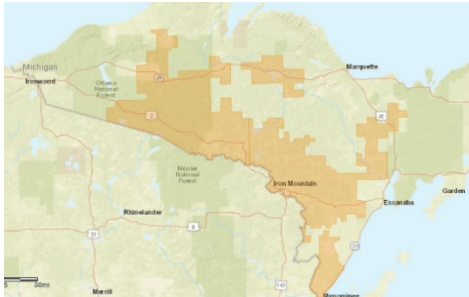


Figure 3 | UMERC Service Territory

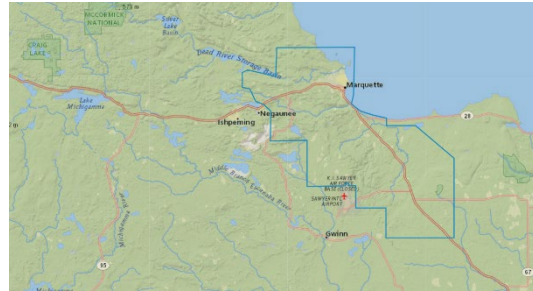


Figure 4 | Marquette Board of Light & Power Service Territory

## **Demographics and Equity Considerations**

UPPCO is committed to making sure that its distribution system equitably serves the residents of its service territory and provides reliable service to all customers. UPPCO has made use of the Michigan Department of Environment, Great Lakes, and Energy’s (“EGLE”) Michigan Environmental Justice Screening Tool (“MiEJScreen”), which is an interactive screening tool that identifies a variety of stressors and demographics within communities that may impact environmental conditions or the public health of residents. This is used to identify areas of the distribution system that may require additional attention due to the demographics of specific regions of their service territory.

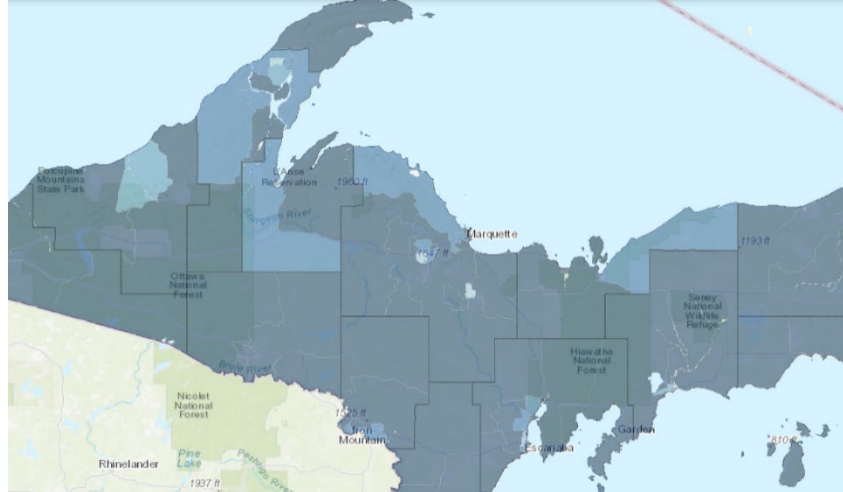
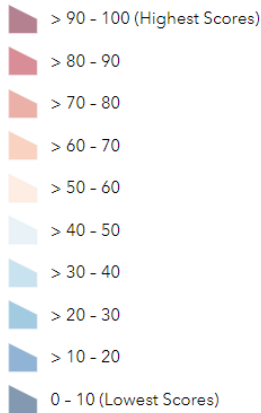
MiEJScreen uses census tracts to divide geographic regions, such as the UP, into smaller areas for socioeconomic analysis. Tracts with higher scores indicate areas that experience a combination of various stressors and potentially increased vulnerability than those with lower scores. Scores can range from 0 to 100%.

Census tracts within UPPCO’s service territory generally score in the 0-30 percentile based on location. These are relatively low scores within the MiEJScreen scoring index and show that UPPCO serves communities with fewer environmental stressors and vulnerabilities. The map below shows the MiEJScreen map in the vicinity of UPPCO’s service territory.



**MiEJScreen Overall Score**

Percentile



*MiEJScreen map in the vicinity of UPPCO's service territory*

The only census tracts within UPPCO’s service territory with overall MiEJScreen scores greater than 30% are census tracts 26061000300 in Houghton County, 26103002000 in Marquette County, and 26041970800 in Delta County. The table below indicates the UPPCO feeders serving portions of these census tracts and their reliability rank out of the 79 feeders ranked in UPPCO’s 3-year ranking of outage data from 2021-2023.

Census Tract	General Area	MiEJScreen Score	Feeder	Total Rank
26061000300	Calumet	32%	703	42
26061000300	Calumet	32%	721	53
26061000300	Calumet	32%	705	58
26103002000	Ishpeming	32%	1203	1
26103002000	Ishpeming	32%	1231	2
26103002000	Ishpeming	32%	1205	17
26103002000	Ishpeming	32%	139	47
26103002000	Ishpeming	32%	1237	52
26103002000	Ishpeming	32%	133	62
26041970800	Wells	35%	587	25

As indicated above, UPPCO’s two worst feeders are located in the Ishpeming area census-tract, which also has a higher MiEJScreen score. These feeders have been prioritized for future capital investment and reliability improvement as discussed later in the Plan. The other feeders listed in the table above rank 17<sup>th</sup> or better and therefore are not currently prioritized for future capital investment over the 5-year budget period.



## **Distribution System**

UPPCO's distribution system consists of approximately 38 distribution substations serving about 54,000 UPPCO customers through nearly 59,000 electric meters. These substations provide the grid interface for UPPCO's distribution feeders, several UPPCO generation facilities and one non-UPPCO generating facility.

The overhead lines consist of approximately 2,170 line-miles of primary, 600 miles of secondary, and 520 miles of service line. The underground lines consist of approximately 810 miles of primary, 45 miles of secondary, and 380 miles of service line.<sup>1</sup>

Much of UPPCO's rural distribution system is routed off the road right-of-way ("ROW"), along lakes, and in cross-country areas that are difficult to access. Consequently, there are approximately 13 meters per line mile of distribution system across UPPCO's heavily wooded service territory. The IEEE-1782-2022, Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events, states in Section 4.3 that "rural" systems consist of less than 50 customers per circuit mile. Based on this definition, UPPCO characterizes its distribution system as extremely rural.<sup>2</sup>

UPPCO's most urban circuit, MTU 1403, consists of 4.8 circuit miles serving 296 customers in the downtown area of the City of Houghton which equates to 62 customers per mile. The next most urban circuit is Elevation 1123 with 48 customers per circuit mile in the City of Hancock. Both of these circuits are also two of the most reliable in UPPCO's system. The number of customers drops to 35 and 34 per mile for the City of Ishpeming and the City of Munising, respectively. UPPCO's top 5 worst performing feeders have the least number of customers per mile of any circuits within the Company's service territory (approximately 8-12 customers per mile).

UPPCO's primary distribution system voltage is 12.47/7.2kV grounded wye. A small, approximately 30-mile, 33kV system is located in the eastern area of the Ishpeming district and is primarily used to tie UPPCO hydroelectric facilities on the Dead River Basin System to the grid, but it also serves some distribution customers along the route. Most of the 33kV system line is routed off the road right-of-way and is in some of UPPCO's most difficult locations to patrol and repair due to the rugged off-road ROW

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<sup>1</sup> Regarding "circuit miles" and "line miles": both circuit miles and line miles account for one-phase, two-phase, and three-phase footage in the same manner. Specifically, one mile of one-phase equals one mile of three-phase. The difference between circuit footage and line footage is that if two circuits are attached to the same structures, i.e., "a double-circuit line," then each circuit counts that footage in the circuit total length, but the common footage is only counted once for the length of the double-circuit.

This difference is relevant when talking about line clearance since the double circuited line is routed in the same right-of-way. Circuit length is relevant when comparing the length of individual circuits within a utility system or between utilities. One other term associated with line and circuit length is "conductor length," which accounts for the footage of each phase conductor plus the neutral conductor. For example, a 200-foot section of three-phase line would be counted four times; 200 feet for each of the three phase conductors plus the neutral conductor equals 800 conductor feet. At this time, conductor-feet is not reported but is relevant when designing the installation or removal of conductor in distribution projects.

<sup>2</sup> This characterization is based on the fact that the meter density across UPPCO's service territory is far less than what would be considered "rural" under the IEEE standard. The IEEE standard does not, however, define the term "extremely rural."



terrain. UPPCO also has two small sections of 6.9kV and 34.5kV in the Delta district that are used to tie into UPPCO hydroelectric facilities. Other hydroelectric facilities are either connected to 12kV distribution lines or directly to a 12kV substation bus.

UPPCO's Geographic Information System ("GIS") platform contains information regarding UPPCO's distribution assets. This system holds the data and locations for assets such as poles, conductor, transformers, reclosers, regulators, and capacitors. It also interfaces with the Customer Information System ("CIS") data which is maintained in UPPCO's SAP system. Therefore, information about customers, such as name, address, and meter number can be obtained through the GIS. The GIS system is the foundation for most of UPPCO's Asset Management processes. Additionally, data from GIS is exported to other systems, like the Outage Management System ("OMS") and Cyme, which is the distribution system modelling system UPPCO uses to perform engineering studies.

### **Overhead System**

UPPCO's overhead distribution system is supported primarily on approximately 73,000 wood poles that are, on average, 39 years old. Appendix 9 to this Distribution Plan, Distribution Plant Depreciation Table, indicates the average expected life spans of various distribution equipment as determined by the MPSC in Case U-21513. This table indicates that the expected life of an average UPPCO utility pole is 49 years old. Nearly 50% of UPPCO's poles were installed prior to 1981, making these poles 44 years old or older and nearing the end of their expected life. Poles weaken with age and are more likely to fail during storm conditions.

A majority of the overhead system consists of various sizes of aluminum conductor steel reinforced ("ACSR"), including #4, #2, 1/0, 4/0, and 336. Typical one-phase systems are constructed as #2 or 1/0 depending on expected loading and voltage stability; #4 is no longer installed and has a history of the steel core rusting, so these are in the process of being replaced as CapEx projects are planned and constructed. Typical three-phase systems are constructed with 1/0, 4/0, or 336 depending on expected normal loading, voltage stability, and/or switching capability.

About 383 circuit miles of UPPCO's 2,170 total overhead primary circuit miles are comprised of copper or copperweld conductor. Copper conductors are generally older and do not withstand tree-related outages as well as ACSR. Copper lines are typically targeted for replacement through the CapEx project planning and prioritization process.

Approximately 19,350 pole-mounted transformers are installed and configured to provide 1, 2, and three-phase service. GIS data indicates that the average age of overhead transformers is about 36 years old.

### **Underground System**

UPPCO's distribution system also includes underground distribution lines. A significant amount of the underground cable was installed in the 1970's with 175 mil insulation and a bare concentric neutral. Historically, this vintage of cable has been more prone to faults, and the neutral could corrode causing a safety hazard and overcurrent protection problems.



The underground system provides service by approximately 4,500 single-phase and 135 three-phase pad-mounted transformers. GIS data indicates the average age of underground transformers to be about 23 years old.

UPPCO has been moving toward installation of underground as the preferred construction for new line extensions and services as well as for system replacements when deemed necessary for capacity, safety, or reliability improvement, or relocations requested by customers or governmental agencies. However, not all CapEx projects are installed as underground. Surface and underground obstacles, like rock or wetlands, sometimes make underground impractical or too costly to construct.

UPPCO's distribution system and major asset information are summarized in Appendix 1, Table 1.



# Distribution Plan Inputs, Methodology & Decision Criterion

UPPCO considers a variety of factors in developing this Distribution Plan and when making decisions on how to invest in its distribution system. UPPCO evaluates reliability metrics, load forecasts, the development of distributed energy resources, electrification of customers' homes and businesses, its own integrated resource plan, its established project prioritization methodology, and performance monitoring metrics that are used to make project adjustments. Each of these factors is described in more detail in the sections below.

## Overview of Reliability Metrics

UPPCO uses a variety of metrics, based on MPSC requirements, to measure the reliability of its distribution system. UPPCO is in the process of updating its systems so that its reporting systems are in full compliance with MPSC rules. The State of Michigan launched the "MI Power Grid" initiative in 2019 in order to increase transparency of Michigan electric utilities' planning activities and to require more in-depth reliability reporting. Subsequently, in 2023, the MPSC approved significant changes to the Service Quality and Reliability ("SQR") Rules, R460.701-752, which had been in place for 20 years. New monthly reporting requirements were required under Case No. U-21122 and changes to the annual reporting were also stipulated in Case No. U-12270.

Since 2012, UPPCO has reported system reliability using the Institute of Electrical and Electronic Engineers ("IEEE") Guide for Electric Power Distribution Reliability Indices, Standard 1366. Specifically, UPPCO reports:

- SAIDI – System Average Interruption Duration Index
- SAIFI – System Average Interruption Frequency Index
- CAIDI – Customer Average Interruption Duration Index

This data is now required for the UPPCO's entire service territory and by circuit or area.

The MPSC approved SQR Rule changes in April 2023. These changes required additional reporting for the following IEEE indices for the entire service territory and by circuit or area:

- CELID – Customers Experiencing Long Interruption Durations
- CEMI – Customers Experiencing Multiple Interruptions
- MAIFI – Momentary Average Interruption Frequency Index
- ASAI – Average Service Availability Index

MPSC SQR reporting requirements also now include the following non-IEEE outage metrics:

- Worst feeders based on SAIDI and SAIFI
- Outages by cause for the system and by circuit or area
- Percentage of customers restored under normal, gray sky, and catastrophic conditions for the entire service territory and by circuit or area
- Storm duration, company & contractor crews used, and costs

Furthermore, the MPSC also requires reporting specific, non-outage related, utility performance metrics, including:

- Meter reading percentage



- New service installations
- Wire down response
- Line clearance progress and spend

Much of the reported data above is not only required for UPPCO’s system, as a whole, but also by “area,” which UPPCO reports by district.

UPPCO’s reporting systems currently face some limitations. UPPCO currently cannot report CEMI and MAIFI due to limitations of the Outage Management System (“OMS”) and Automated Meter Infrastructure (“AMI”), and received a waiver for these metrics until April 30, 2025, in Case No. U-21420. Technology improvements to enable reporting of these metrics are underway; more detail is provided about these efforts in the section called “Grid Modernization” below. Specifically, there are multiple projects that UPPCO staff are working on with AMI and OMS vendors to provide improved outage reporting tools.

UPPCO’s OMS captures and records sustained customer interruptions and is UPPCO’s system of record for customer outage events. The OMS is not only an operating system used to help locate and direct crews to the outage device, but also consists of a database for outage records storage and includes data on outage duration, number of customers affected, outage cause, feeder, and device name and type. This data is necessary to fulfill the MPSC’s reporting requirements and is considered UPPCO’s primary source for reporting outage data. UPPCO also uses its recently implemented AMI system to confirm outage data, as deemed necessary, to accurately maintain and report outage data.

UPPCO removes transmission-caused outages from its filed reliability indices calculations based on language in IEEE 1366-2022, Section 6.2, which states, “Interruptions that occur as a result of outages on customer-owned facilities, or loss of supply from another utility, should not be included in the index calculation.” UPPCO does not own any transmission lines. ATC is the transmission utility that owns and operates the transmission lines serving UPPCO’s service territory, so outages caused by loss of transmission services are not included in UPPCO-specific reliability indices.

In 2013, the State set goals for electric reliability in Michigan. These goals were that utilities have a SAIDI of less than 150 minutes per year and a SAIFI of no more than one (1) event per year. On October 17, 2019, in Case No. U-20645, the MPSC ordered the creation of the “MI Power Grid” to outline performance requirements and improve service quality and electric reliability in Michigan. UPPCO endeavors to improve the resilience and reliability of the Company’s distribution system in order to meet the Michigan reliability expectations and improve the customer experience.

While it is desirable to compare utilities’ reliability performance to one another or to industry benchmarks, UPPCO feels there are limitations to these comparisons. There are many unknowns regarding the data reported by the different utilities. The IEEE Power & Energy Society (PES) Distribution Reliability Working Group compiles reliability data from utilities that voluntarily submit it to create and publish their reliability quartiles. Because these are voluntary submissions there is some inherent inaccuracy in the quartiles.

There are other issues beyond the voluntary nature of the data submitted. Although using the IEEE-1366 standard for reporting reliability metrics implies consistency, inaccuracies in industry benchmark data can also be created in the way utilities collect outage data. The number of customers experiencing an



outage and the duration of the outage are critical elements for accurately calculating reliability metrics. Accuracy of the customer and duration can vary from one utility to another depending on many factors.

For example, there can be differences based on whether a utility collects data from an outage management system (“OMS”) rather than from paper outage reports. An OMS is only as accurate as the model upon which it is built, such as a geographic information system (“GIS”) and how often customer data and the system model is updated within that system. Additionally, it is unknown what outage data a utility includes or excludes in reliability indices reporting. For example, some state rules, which vary state by state, may drive how utilities define and report outages in that state. Some utilities may include planned outages while others may not. And utilities may interpret what is meant by a planned outage differently from one another.

Also, geography and weather conditions can make a significant difference in outage susceptibility and therefore also in outage reliability metrics. For example, a line routed through a desert would have less susceptibility to tree-related outages, than lines in UPPCO’s system which are often located in heavily forested areas. As further examples, utilities in the southeastern United States are more susceptible to hurricanes and those in the Great Plains States are more susceptible to tornadoes. Calculating the IEEE-1366 metrics excluding major event days (“MEDs”) helps to flatten the peaks due to major weather events but does not completely eliminate the impacts of major events on the shoulder days of storms. This is referenced in more detail below.

Although UPPCO does not use industry quartile average reliability benchmarks to set reliability goals, Appendix 1, Table 2b, indicates UPPCO’s SAIDI excluding MEDs along with other Michigan utilities, IEEE quartiles, and EIA-861 data for the 5-year period from 2019-2023. UPPCO’s SAIDI is trending lower than, but about on the same trajectory as, the average of other Michigan utilities in the data set over the 5-year period. The EIA-861 utility average SAIDI as well as the IEEE Q1/2 and Q2/3 trendlines are nearly flat, and the IEEE Q3/4 trendline is increasing over the period.

UPPCO’s reliability goals are targeted toward gradual improvement each year and UPPCO manages capital and O&M expenditures to that end. UPPCO’s other main goal is to meet and exceed MPSC Service Quality Rules for service quality and reliability to its Michigan customers. UPPCO’s linear trendline shown in Appendix 1, Table 2b, indicates a steady improvement over the past five years.

UPPCO uses IEEE reliability metrics extensively to assess the reliability of UPPCO’s system overall and to guide Distribution Engineering to the worst areas of the system to implement reliability enhancements.

UPPCO sets an aggressive SAIDI goal each year based on 90% of the previous 5-year average SAIDI, excluding MEDs. The SAIDI target in 2023 was 163 minutes and for 2024 was 164 minutes. Note, because the actual SAIDI can vary significantly from year to year, the 5-year average will also fluctuate depending on the magnitude of the first year of the 5-year average that falls out of the data set each year and the most recent year which is added to the data set. UPPCO does not create goals for all-weather conditions due to the significant variability of reliability metrics due to storms, nor does it set goals for SAIFI or CAIDI.

UPPCO relies heavily on outage data to evaluate the ability of the distribution system to recover from weather-related and human-caused outage events. This data is analyzed in different ways to help determine effective reliability projects.



MEDs can greatly influence reliability metrics and are strictly determined by the SAIDI minutes of each calendar day in which UPPCO customers experienced outages as prescribed in IEEE-1366. The daily SAIDI is determined by the off-time of outages beginning at 00:00:01 (i.e. just after midnight) until 24:00:00 (midnight). There is no consideration for weather-related events that begin hours before midnight and run through the next day, or for events that continue beyond midnight following a major event day.

For example, if storm begins at 6PM on day one and accumulates 15 SAIDI minutes in calendar day one and continues until 6PM on day two and accumulates 15 more SAIDI minutes in calendar day two and the TMED is 20 minutes, then neither day meets the definition of an MED, even though the storm caused 30 SAIDI outage minutes. Storms do not typically begin and end within a calendar day from midnight to midnight, and the SAIDI minutes that accumulate on non-MED “shoulder” days can significantly impact the “all weather” reliability metrics (SAIDI, SAIFI, and CAIDI).

Appendix 1, Table 2a, Historical Reliability Indices, indicates UPPCO’s system reliability indices for the years 2019 through 2023 for all weather conditions and excludes MEDs.

In 2023, excluding transmission-caused events and MEDs, UPPCO’s SAIDI was 141 minutes, and SAIFI was 0.98 events per average UPPCO customer. However, UPPCO’s 5-year average all-weather SAIDI 2019-2023 SAIDI was 446 minutes, and the 5-year average all-weather SAIFI was 1.84 events. For this reason, UPPCO continuously strives to improve its customer experience by increasing system reliability and resilience and considers MEDs in its reliability improvement project planning and prioritization processes.

Comparing the annual SAIDI data, excluding MEDs, reported for the years 2019 and 2023 in the UPPCO System Reliability Indices Table 2a in Appendix 1, the data indicates that UPPCO’s reliability is improving, and its outage metrics are on a downward trend. This, in part, is due to UPPCO achieving a 6-year line clearance cycle following completion of UPPCO’s accelerated line clearance program from 2014-2017. However, the decline has not been a straight line over this period and shows an increase in 2022. Major storms have a dramatic impact on the reliability indices even with the major event days removed from the data set due to outages on the days immediately before and after an MED.

The data in Table 3, Historical Major Event Days and Historical Catastrophic Events, in Appendix 1 show the number of MEDs by year with the corresponding Threshold of a Major Event Day (“TMED”) versus the company’s SAIDI goal and actual annual SAIDI, excluding MEDs, along with a listing of catastrophic events dates and causes for the period of 2019 to 2023.

As shown in Table 3, there was only one MED in 2020 and 2021, but five in 2019. Although MEDs are removed from the reporting data there is overlap of outages on the adjacent days before and after a MED, referred to “shoulder” days that do not exceed the threshold of a major event day and are not included in the MED. As per the guidelines in IEEE-1366, MEDs are from midnight to midnight, statistically, regardless of when the storm actually started. Partial storm days may or may not meet the threshold of a MED, but in UPPCO’s experience, storm restoration efforts may begin prior to meeting the TMED and continue into the following days after the MED concludes.

As shown in Table 3, in 2019, UPPCO customers experienced five (5) MEDs. Four of these MEDs occurred over a 5-day period in late November and into December during the most significant catastrophic storm event to UPPCO service territory in 25 years. During the 5-day period of November 27 to December 1, 2019, the daily SAIDI values were as follows:



<u>Date</u>	<u>SAIDI (minutes)</u>
Nov. 27	311
Nov. 28	158
Nov. 29	24
Nov. 30	16
Dec. 1	48

The TMED in 2019 was 17.0 minutes, therefore, November 30 did not qualify as an MED even though the outage minutes were as a result of the catastrophic storm conditions that began on November 27. The outage minutes occurring on November 30 account for nearly 8% of the total 2019 annual SAIDI excluding MEDs for that one day only.

In 2020, UPPCO experienced only one MED, however, two other dates in 2020 had daily SAIDI's of 17.1 minutes each day, which is just under the TMED of 17.4 minutes, thus increasing the annual SAIDI excluding MEDs by 34.2 minutes and accounts for nearly 17% of the annual total in 2020.

In 2022, UPPCO customers experienced four (4) MEDs. Outages on shoulder days, just before or after the MEDs, account for more than 25 SAIDI minutes, which account for 12% of the total SAIDI, excluding MEDs, in 2022.

The discussion above regarding MEDs and the reliability metrics excluding MEDs emphasizes the fact that significant weather-related events (whether they be on shoulder days around an MED or result in daily SAIDI values just under the TMED) can have a large impact on the cumulative SAIDI over the course of a year, and accounts for the variability in annual SAIDI from year to year.

In general, UPPCO's SAIDI is trending lower primarily due to the following major factors:

1) UPPCO's continued emphasis on its on-cycle line clearance program with the additional identification and removal of hazard trees, and 2) effective and targeted system reliability improvement programs, such as storm hardening and asset replacements. These will be discussed in more detail in the sections below. UPPCO will continue to direct capital and maintenance expenditures toward effective storm hardening and reliability projects to reduce UPPCO's SAIDI over time and improve customer experience.

Even outside of MEDs, weather is a major cause of outages. As shown in Appendix 1, Table 4a, Outages by Cause, for all-weather conditions and excluding MEDs, which depicts the 5-year totals for the years 2019 to 2023 of all outages by cause, vegetation-related outages represent the largest impact to customers in terms of SAIDI, number of events, and the number of customers affected under both All-Weather and Excluding MEDs conditions. In terms of SAIDI, weather-related events are the second leading cause in the All-Weather data set, followed by equipment-related issues, which are flip-flopped in the Excluding MEDs data. This inherently makes sense since MEDs are weather-based and should impact less customers when MEDs are excluded from the data set. This does indicate, however, that weather is a major contributor to outages even when the conditions do not meet the definition of a major weather event.

Underground distribution systems are much less at risk for weather and vegetation-related outage events than overhead systems. Therefore, in an effort to continue to reduce SAIDI, UPPCO's system hardening and reliability improvement projects are primarily directed toward the overhead system.



## **Load Forecasting**

Load forecasting plays another key role in UPPCO's distribution planning process. UPPCO performs a detailed load forecast for each substation bus on an annual basis. This data feeds into the ATC load forecast, which, in turn, feeds into the Midcontinent Independent System Operator ("MISO") load forecast.

The forecast is based on UPPCO's system coincident peak demand for the year at the day and hour of the ATC system peak. The actual bus loads during the ATC peak are used to calculate UPPCO's 10-year annual average system load growth. Refer to Appendix 1, Tables 5a and 5b, 10-Year Historical Loads and 10-Year Load Forecast. Based on this data, from 2014 to 2023, the average annual system load growth was 2.0%.

Because this forecast is based on actual system loads, it therefore includes the effect of small distributed energy resources ("DERs") that have been added to UPPCO's distribution system that were either in operation or, conversely, not operating at the time of the system peak. At this time, UPPCO does not have the ability to determine the coincident loading and DER generation on the system at any point in time.

However, individual feeder peaks are used in the Cyme model for load flow, voltage studies, and system analysis. Cyme is used to assess feeder capacity limitations or where further voltage investigation and analysis may be required. When further investigation is required, UPPCO will request that field personnel install voltage recorders as warranted to obtain actual voltage measurements to confirm Cyme models.

## **Distributed Energy Resources**

UPPCO continues to monitor the impacts of development of Distributed Energy Resources in its territories and its impact on its distribution system to inform its distribution planning processes. Distributed Energy Resources are typically connected to the distribution system at a customer's premises. DERs provide energy into the distribution system, and hence to the grid via the distribution system. DERs include all forms of energy connected to the distribution system. In addition to distributed generation, such as wind, solar, and methane, DERs can also include stored energy, like batteries and water.

The distribution system was designed for one-way power flow from utility generation sources to the customer. Over the past 20+ years, the nature of the electric generation system has changed such that not only electric utilities own generation assets. Independent power producers, who may connect to the grid at transmission level voltages or, more recently, at distribution voltages, own increasing amounts of electric generation capacity. The generation interconnections at distribution voltages may be at a distribution substation bus or on the distribution lines themselves either at primary distribution voltage, 7.2/12.47kV, or at secondary or service level voltages, such as single-phase 120/240V, or three-phase 120/208V or 277/480V. Due to UPPCO's rural and sparsely populated service territory, DER interconnections at distribution level voltages, whether primary or secondary, can create new challenges for the distribution system. Challenges can develop for voltage regulation and overcurrent protection (e.g., DERs can result in reverse energy flow on the system), but also in power quality due to harmonics.



At the present time, UPPCO has just over 300 DERs interconnected to its distribution system that produce less than 20kW and less than 10 DERs interconnected to its distribution system that produce more than 20kW but less than 150kW. Due to the slow rollout of DERs within UPPCO service territory, Distribution Engineering does not currently create a DER forecast or attempt to predict DER impact on the distribution system. Instead, DER development is addressed on a case-by-case basis as requested. UPPCO's Distribution Engineering department models larger proposed DER projects of 50 kW or more in Cyme to determine if the existing system can support the proposed energy resource at the location or if some system modifications or upgrades may be required.

The development of DERs that interconnect to UPPCO's distribution system present unique challenges for UPPCO's distribution system, which are briefly mentioned above, that UPPCO will continue to monitor. Due to UPPCO's relatively lightly loaded circuits, significant development of DERs in a small geographic area on a section of line will likely result in backflow of energy toward the substation. This may negatively affect overcurrent protection schemes and will result in electricity flowing in the opposite direction and affecting the voltage of end-use customers if voltage regulators are not equipped with reverse-flow technology. This situation requires close monitoring and analysis of system load flow as DERs become more prevalent and may require upgrades to the overcurrent protection plans as well as voltage regulation.

## **Electrification**

UPPCO takes electrification – particularly the increased use of electric vehicles and air-source heat pumps – into consideration when evaluating the best path forward to maintain reliability on its distribution system. Electrification has been defined in many ways over the past several years. The Department of Energy defines the term as follows:

*“Electrification converts an energy-consuming device, system, or sector from non-electric sources of energy to electricity. It’s an emerging economy-wide decarbonization strategy that is beginning to impact the electric power industry.*

*Electrification is not necessarily the goal, rather a means to achieving a community goal such as reducing greenhouse gas emissions or lowering energy costs. For utilities, the goal—or the benefits—of electrification might be to support system optimization, improve efficiencies, and increase resiliency. Ultimately, people and businesses will choose beneficial electric technologies.”*

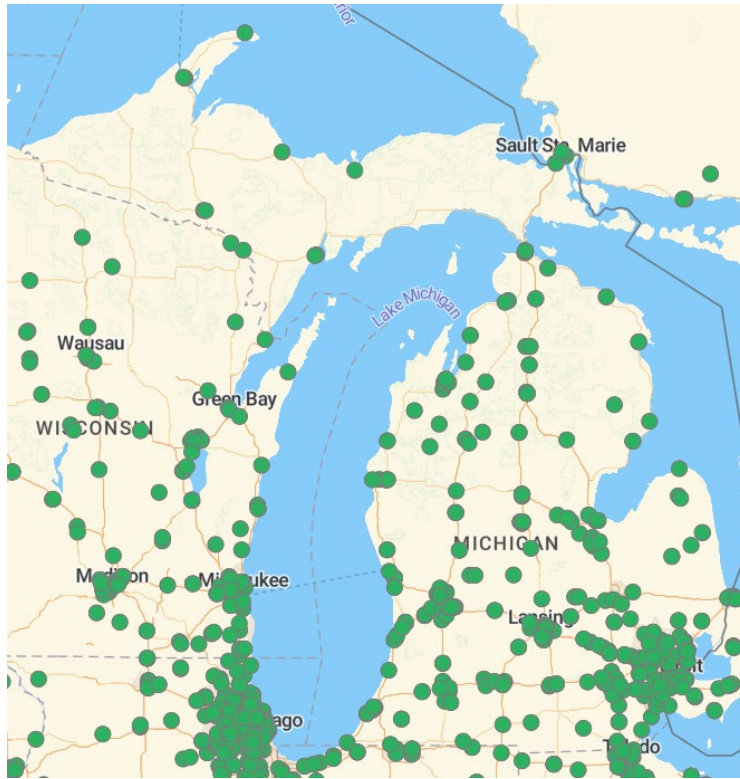
Source: What is Electrification, U.S. Department of Energy, <https://www.energy.gov/electricity-insights/what-electrification>.

UPPCO will address two developing forms of electrification within this Plan: 1) electric vehicles and 2) air-source heat pumps.

### **Electric Vehicles**

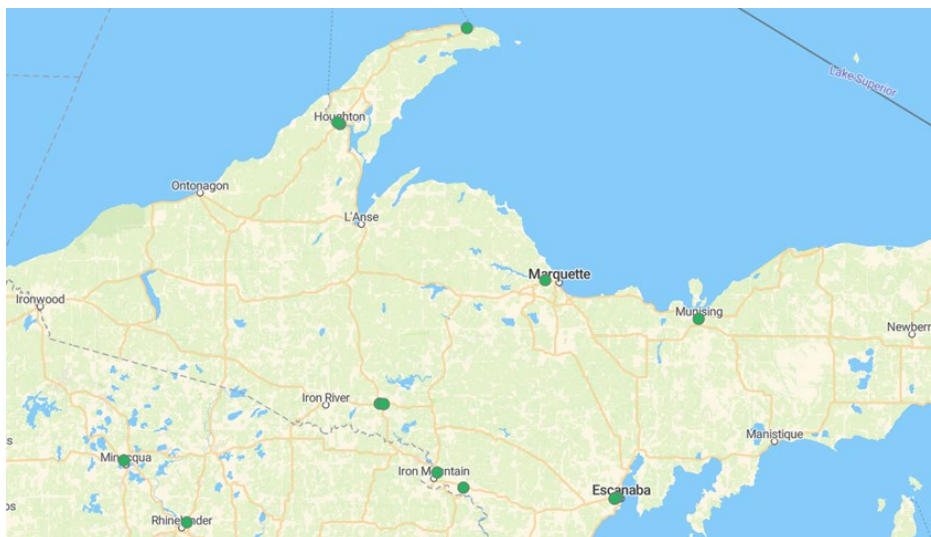
UPPCO has actively worked to guide the uptake of electric vehicle charging stations in its service territory to both increase their presence and limit their potential negative impacts on UPPCO's distribution system. Compared to other areas of Michigan and the United States overall, the rollout of electric vehicles in UPPCO's service territory has been slow. At present, there are very few electric vehicle charging stations within UPPCO's service territory.

The map below indicates the Direct Current Fast Chargers (“DCFCs”) currently installed in Michigan and the surrounding areas:



US Dept. of Energy, filtered on DC Fast Charger Locations | Source: <https://afdc.energy.gov/fuels/electricity-locations#/find/nearest?fuel=ELEC>

The zoomed-in map below better indicates the current locations of DC fast chargers within the UP and UPPCO’s service territory, which are in Hancock, Houghton, Copper Harbor, and Munising:



DC fast chargers within the UP and UPPCO's service territory



The Cities of Houghton and Hancock each installed a fast charger within their city limits in 2022 and 2023, respectively. The Copper Harbor charger, located in the parking lot of a local restaurant, is privately owned and operated and was also placed in service in 2023. A DC fast charger was also recently installed and placed into operation in the City of Munising in 2024. Other locations pictured with DC fast chargers are not served by UPPCO. Additionally, UPPCO is currently working with customers in Seney and Hancock to install DC fast chargers in mid-2025.

UPPCO has sought to increase the presence of electric vehicle chargers (EVCs) in its service territory. In its ex parte application, filed in Case No. U-21137, UPPCO requested and was ultimately authorized to modify its small commercial rate, C-1, to incentivize customers to install DC fast chargers for general public use. The C-1 rate requires a demand charge if the customer's load exceeds 25 kW for three consecutive months. Prospective DCFC installers had expressed concern that the demand charge makes fast charging uneconomic since DCFCs typically charge with a high current draw that tapers off as the electric vehicle battery is charging. The tariff was modified on a temporary basis to waive the demand charge for dedicated, stand-alone DCFCs that are installed for public use.

The updated rate and demand waiver have several limitations stipulated in the Case:

1. The maximum 15-minute average demand cannot exceed 150 kW.
2. DCFC must be served by a new, dedicated service.
3. The DCFC service cannot service other non-DCFC loads.
4. The applicant must be an existing UPPCO customer or eligible to take service from UPPCO.
5. The DCFC must be located where existing distribution system can support the additional load without material modifications.
6. The demand waiver expires January 1, 2027.

As part of the Case, a regulatory asset was created to track UPPCO's contributions associated with new DCFC installations supporting the Environment, Great Lakes and Energy's (EGLE's) DCFC grant application process.

UPPCO Account Executives and Distribution Engineering worked directly with the developers of the DC fast chargers currently available for public use in Copper Harbor, Houghton, Hancock, and Munising, which can output up to 175, 62.5, 62.5, and 100 kW respectively. UPPCO staff assisted with the general location of the charger installation as well as the electric service construction. In this way, UPPCO has worked to guide EVC developers to locations with adequate capacity and help minimize the complexity of the utility connection. The developer of the 175kW EVC in Copper Harbor enabled a software feature to limit its output to 150kW to assure it does not exceed the demand limit of the C-1 rate discussed above. The EVC planned in Seney is slated to have a 200kW output capacity but will be programmed to limit output to 150kW.

Level 1 and 2 EVCs can connect at typical home or business service single-phase voltages of 120 or 240V. DC fast chargers, on the other hand, typically use three-phase voltage and can draw significantly more load.

The following charts provided by the U.S. Department of Energy indicate typical charging levels for the various types of chargers and connectors:

LEVEL 1 CHARGING	LEVEL 2 CHARGING	LEVEL 3 CHARGING
<ul style="list-style-type: none"> <li>Requires 30 hours for full charge.</li> <li>Uses a standard 120-volt household outlet.</li> <li>Provides approximately 5 miles of range per hour of charging.</li> </ul>	<ul style="list-style-type: none"> <li>Requires 4-7 hours for full charge.</li> <li>Uses a 240-volt outlet.</li> <li>Can be used at home or in public charging stations.</li> <li>Provides approximately 25 miles of range per hour of charging.</li> </ul>	<ul style="list-style-type: none"> <li>Requires 20-30 minutes for 80% charge and 1 hour for a full charge.</li> <li>Uses a public charging station.</li> <li>May affect battery performance and life with frequent use.</li> <li>Provides approximately 100-200+ miles of range after 30 minutes of charging.</li> </ul>

US Department of Energy, Electric Vehicle Charger Types | Source: <https://www.energy.gov/energysaver/how-charge-electric-vehicles>

J1772 (LEFT, WITHOUT CCS CONNECTER; RIGHT, WITH CCS CONNECTOR)	CHADEMO	J3400 (NACS)
<ul style="list-style-type: none"> <li>Standard with most EVs.</li> <li>Works with level 1 and 2 charging.</li> <li>Needs a combined charging system (CCS) connector for public DC fast charging.</li> </ul>	<ul style="list-style-type: none"> <li>Available on some vehicles, often Japanese automakers.</li> <li>Works with DC fast charging but not at stations with only CCS connectors.</li> <li>May need an adapter.</li> </ul>	<ul style="list-style-type: none"> <li>Works for all charging levels.</li> <li>Standard on Tesla vehicles.</li> <li>Being standardized for use across all EVs and charging stations. <a href="#">Read more about standardization</a></li> </ul>

US Department of Energy, Electric Vehicle Charger Connectors | Source: <https://www.energy.gov/energysaver/how-charge-electric-vehicles>

Due to the relatively small electric load of Level 1 and 2 chargers, UPPCO may or may not become aware of their installations within UPPCO’s service territory. If the charger requires a service upgrade at the home or business, UPPCO would be involved at the time the customer requests the service. At this time, UPPCO’s process for these installations includes Distribution Engineering evaluating the existing electric distribution system at the customer location to determine if the primary or secondary system capacity is adequate or if it may require an upgrade.

UPPCO does not anticipate needing to make major changes to its distribution system to accommodate the installation of EVCs at customers’ homes. UPPCO’s customer density is quite sparse across its service territory and a service transformer may only serve one or two customers.

According to the US Department of Transportation, Level 2 chargers may draw approximately 7-19 kW. See Charger Types and Speeds, U.S. Department of Transportation, <https://www.transportation.gov/rural/ev/toolkit/ev-basics/charging-speeds>. Level 1 chargers draw less electric power than Level 2 units. Because Level 1 and 2 EVCs draw a relatively small load, typically only a transformer and/or service conductor replacement may be required to serve this additional load.

Additionally, UPPCO has not experienced groups of homes within its more urban service territory, such as subdivisions or neighborhoods within cities or villages, where installing EVCs would necessitate a capacity increase on the primary system. In fact, none of the three DCFCs already installed required a change to UPPCO’s primary system, although the Houghton DCFC did require a three-phase extension approximately 350 ft from the existing three-phase system.

Due to the slow and somewhat random integration of electric vehicles across Michigan’s UP, discussed above, UPPCO has not planned any system upgrades for EVC installations at this time. Within the next 5-



year budget horizon, UPPCO will continue to monitor EVC development and expansion into its service territory, work directly with EVC developers, and plan for the additional load accordingly.

Longer term, UPPCO will need to create future scenarios of the future distribution system considering expansion of residential, business, and municipal/public-use EVCs. This will require a more detailed study of current load profiles along all segments of the distribution system. Within the 5-year budget horizon, UPPCO expects to develop tools to better utilize AMI meter load data, which can be used to more fully and accurately populate UPPCO's load-flow tool, Cyme. Cyme's output data along with an interface to UPPCO's GIS can provide a visual representation of the distribution system's potentially vulnerable areas and allow UPPCO's distribution engineers to plan necessary capacity upgrades over a period of time.

UPPCO has also hired a consultant to perform a transportation electrification plan, for the purpose of supporting the Company's Beneficial Electrification Plan which will be filed with the Commission in mid-2025. At that point, the Company will have a better understanding of the distribution system upgrades that are necessary to support a measured increase in the penetration of EVs within its service territory.

### **Heat Pumps, Air-Source**

UPPCO also has taken the increased use of air-source heat pumps into consideration as it has evaluated the impacts of electrification on the reliability of its distribution system. The uptake of air-source heat pumps for heating and cooling is very slowly increasing. For new or replacement heat systems, UPPCO's experience indicates that the HVAC contractors do not believe in the technology yet, so they often convince customers to install new furnaces or boilers. However, if customers currently have an electric heating system, the installation of a heat pump is a relatively easy sell and upgrade. But the number of customers that currently have electric heating systems is limited and more prevalent in low-income rentals where the landlords are reluctant to make improvements.

At this time, UPPCO does not have data indicating the number of customers using air-source heat pumps. Data from UPPCO's customer information system shows that approximately 6% of residential customers and about 3% of commercial customers are on UPPCO's electric heating rate. However, the electric heating rate also includes electric baseboard and geothermal water-source heating.

Air-source heat pumps could be installed to replace, or supplement, baseboard electric, oil, natural gas, or propane heating systems. If a heat pump is used to replace baseboard electric heat as the primary heat source, the loading during the heating season would be reduced due to the higher efficiency of air-source heat pumps compared to baseboard electric heat. On the other hand, if heat pumps are used to supplement an existing primary heat source, it will be an additional load on the electric distribution system.

Like small Level 1 and 2 EVC installations, residential or small commercial heat pumps may be added to the customers electric system without UPPCO's involvement or knowledge. The installation of a heat pump is similar to a customer adding a hot tub or central air conditioner. In most cases, the existing primary distribution system can serve the new load without system upgrades. Similar to how UPPCO manages the installation of electric vehicle chargers, UPPCO staff works directly with customers installing heat pumps to assure system capacity is adequate to serve the new load whether it be for supplemental heating or as the primary heat source.



The installation of heat pumps presents unique potential challenges compared to other electric heating systems. Unlike the other heating systems, air-source heat pumps can also be used for room air conditioning. Therefore, as more heat pumps are installed, this could increase load demand during the warm summer months and contribute to the summer peak load. Indeed, for cooling, UPPCO’s experience indicates more customers are installing heat pumps over a central A/C unit because of the energy efficiency, upfront heat pump rebate, ease of installation, and long-term savings.

UPPCO will continue to closely monitor the installation of air-source heat pumps and their use for air-conditioning during the summer months because of the potential impacts on the distribution system. Additional load during the winter months has less impact than additional summer loading because UPPCO’s electrical equipment located in the cooler outdoor temperatures can withstand additional loading without degradation to the equipment’s insulation system.

UPPCO continues to encourage the installation of heat pumps in its service territory because they are more energy efficient than other forms of heating. Through its energy efficiency program, UPPCO currently offers a rebate for air-source heat pumps to encourage replacement of baseboard electric heat and other forms of primary heating. UPPCO also offers rebates for the installation of heat pump water heaters, which are typically installed to replace electric resistance water heaters and decrease demand from about 4500W to about 500W and energy usage (kWh) by approximately 60-70%. UPPCO assistance is provided through the following programs:

- *Empower - Low-income, less than 150% Federal Poverty Level*
- *REI - Residential Energy Insight, any residential customer not low-income*
- *BEEP - Business Energy Efficiency Program, small to medium commercial accounts*
- *New Home - New Home Construction Program, residential customer not low-income*

The tables below show the number of cold climate heat pump (CCHP) projects and heat pump water heater (HPWH) counts for the past three years:

**CCHP Projects**

Program	Empower	REI	BEEP	New Home	Total
<b>2022</b>	18	15	0	0	33
<b>2023</b>	19	21	1	7	48
<b>2024</b>	2	24	4	6	36
<b>Grand Total</b>					<b>117</b>

**HPWH Units**

Program	Empower	REI	BEEP	New Home	Total
<b>2022</b>	24	4	0	0	28
<b>2023</b>	18	6	0	0	24
<b>2024</b>	9	6	0	2	17
<b>Grand Total</b>					<b>69</b>

To the extent possible, UPPCO will continue to monitor air-source heat pump expansion throughout its service territory, work directly with customers installing heat pumps, and plan for the additional load accordingly.



## **Integrated Resource Planning**

UPPCO also considers its Integrated Resource Planning process in its distribution planning and management decisions. UPPCO intends to file its next Integrated Resource Plan (“IRP”) in February 2025. In this plan, the Company will evaluate the impacts of several scenarios and sensitivities related to DER installation, load growth, and changing generation resource portfolios. Over time, to the extent that any of these future states become reality, the Company’s existing distribution planning methodology will organically adjust to prioritize the necessary infrastructure changes to accommodate the changing landscape as laid out in the IRP.

## **Prioritization Methodology**

UPPCO uses a prioritization methodology to identify and plan for distribution maintenance and replacement projects with the goal of maintaining and improving the reliability of its distribution system. While, at this time, UPPCO does not utilize a formal business case analysis to prioritize projects that are meant to improve system reliability, UPPCO’s prioritization methodology and the many factors that it includes allow the Company to make informed decisions about strategic reliability projects that improve value for UPPCO customers. As mentioned previously, UPPCO’s distribution system consists of nearly 4,500 circuit miles of line. In a typical construction year, UPPCO may replace only a few miles of line each year, therefore, CapEx budget dollars are typically targeted to the areas in most need of reliability improvement.

Additionally, some projects arise requiring capital expenditures that are not necessarily needed for reliability improvement, but rather to maintain adequate voltage and capacity of the system. Other projects that cannot be predicted including, government-initiated road relocations, storm damage, inspection results mitigation, underground cable failures, and public interference, such as car-pole accidents and underground dig-ins, also arise with relative frequency.

### **Project Classification**

Because of the limited number of CapEx dollars available for reliability improvement projects, UPPCO places a project classification tag on each Distribution CapEx project to guide project selection. The project classification system is used to provide a quick reference for internal UPPCO use to delineate the need for specific projects and to help prioritize budget dollars and project construction. This classification system is referred to as the “RASCL” system and uses the following factors to classify projects:

- R – Reliability/Storm Hardening
- A – Age & Condition
- S – Safety
- C – Compliance/Voltage
- L – Load/Capacity

Individual projects can fit into one or more of the RASCL classifications. Reliability and Age & Condition often overlap in outage statistics. Therefore, UPPCO uses other criterion to help indicate the best locations to direct capital improvements. Compliance/Voltage and Load/Capacity projects are typically



not optional. These are projects required to maintain the distribution system in a safe condition that is fully capable of serving peak load under all conditions. After mandated projects are penciled into the budget, capital budget dollars are then allocated for distribution reinforcement projects at the specific locations that have the greatest need.

### **Decision Criterion**

Beyond the classification, UPPCO also uses a variety of factors to determine which capital projects should be prioritized. UPPCO typically uses the following decision criterion to prioritize its capital projects:

1. IEEE Indices (SAIDI, SAIFI, and CAIDI)
2. Worst Feeder Ranking
3. Multiple Device Operations
4. Field Crew Experience
5. Inspection Results

Each of the decision criterion are described in detail below.

### **IEEE Indices**

As mentioned in the Reliability Metrics section above, the IEEE reliability indices are typically used to compare performance among utilities. This data, however, can be and is used internally to compare performance among different districts, feeders, or even down to the device level. These comparisons may be used to determine which districts, feeders, devices, and line segments are in most need of maintenance or replacement to maintain and improve reliability.

### **Worst Feeder Ranking**

UPPCO's methodology to analyze where to invest in reliability improvement or storm hardening is partly based on a ranking of UPPCO's feeders. For purposes of ranking UPPCO's worst feeders, UPPCO uses the IEEE indices of SAIDI, SAIFI, and CAIDI as well as the number of outages per feeder.

An analysis of the reliability indices by individual feeder, or circuit, considers the effect of outages on a specific feeder not only as it relates to the average UPPCO customer, but also as it relates to the geographic region where that feeder is routed. UPPCO typically uses the 3-year outage history for the entire system to help prioritize capital improvements by feeder, at times the 5-year and 2-year outage histories are used to best determine where the biggest reliability improvements are necessary.

A point system is used on each of the four measures (SAIDI, SAIFI, CAIDI, and number of outage events) with the worst feeder in each category getting the top ranking as the worst feeder. UPPCO has about 79 feeders in the 3-year data set, so the worst feeder in each category is assigned one point and the best feeder for each category is assigned 79 points. The points are added for each of the four measures, and the feeder with the least number of points is considered the worst reliable overall and ranked as the worst overall feeder.

UPPCO's current feeder ranking for 2021 through 2023 is included in Appendix 1, Table 6, *UPPCO Worst Feeder Ranking*.



## **Multiple Device Operations**

Another factor that UPPCO uses to select distribution Reliability/Storm Hardening and Age/Condition improvement projects is the number of device operations. Except for those feeders serving customer load directly from a substation bus, the average UPPCO circuit length is over 62 line-miles per feeder and 20% of the most rural feeders are over 100 line-miles in length. UPPCO's feeders are inherently long electrical circuits and as such, one project cannot improve an entire feeder's reliability. Therefore, UPPCO uses the multiple device operations metric to pinpoint where reliability improvement work is most warranted on a specific feeder to enhance reliability for the most customers.

## **Field Crew Experience**

UPPCO also uses the expertise and experience of its employees as a factor in prioritizing projects. Line personnel are quite familiar with outage-prone areas. UPPCO frequently interviews its crew so that their operational experience can be used to help Engineering determine areas where targeted capital expenditures can best improve system reliability.

## **Inspections**

UPPCO also considers other ongoing maintenance activities, such as annual overhead line inspections, to determine which projects would most enhance system reliability. For example, if several poles along a line require replacement due to the inspection results, UPPCO may consider rerouting the line section underground, or replacing the poles with larger poles instead of a like-for-like replacement.

## **Project Costing**

UPPCO also uses its design tool, also known as the "Staking Tool," to create detailed estimates for construction based on actual conditions observed by UPPCO designers in the field, such as rock, pavement, driveways, road crossings, brushing, and other surface and underground obstacles. These cost estimates are also used to prioritize reliability enhancement projects. UPPCO previously used a Staking Tool designed by Ptarmigan starting in 2015, but recently transitioned to a new tool called Stakeout, which was developed and provided by GeoDigital Inc., in 2024.

The Staking Tool uses current material, labor, equipment, and underground contractor rates to calculate a detailed estimate and a comprehensive sketch for construction. The estimate is developed using UPPCO's current distribution construction standards, best practices, and engineering guidance.

High level "per foot" estimates are developed for budgetary purposes. The by-foot estimates are based on typical job parameters, material, labor, equipment, and contract costs. The estimated costs for overhead projects include initial line clearance and cycle clearance for the expected life of the project as well as the annual increased maintenance cost of overhead versus underground as discussed previously. Line clearance is typically required for overhead projects, but the cost can vary substantially due to many factors, such as the last cycle trim in the area, possible rerouting, additional pole height, etc. Therefore, for the purpose of these high-level estimates, UPPCO feels that the historical cycle clearance cost is a good average to use for the initial line clearance cost for overhead projects.



Permitting, easements, outside engineering, and special equipment costs are not included in these by-foot rates because they are not always required for UPPCO reliability improvement projects and can be quite variable when they are necessary depending on the specific conditions of the project site.

Prior to construction, UPPCO Designers complete a field review and detailed design/estimate. For the detailed design, UPPCO designers take field measurements, and determine the construction standards, installation methods, and equipment needed to construct the proposed distribution project. At this time, the designer identifies if any additional project-specific costs would be incurred, such as permitting, easements, outside engineering, or special equipment. The field information is then put into the design software which will calculate the material, labor, and equipment costs and apply the material and labor overhead percentages. On occasion, reliability improvement project scopes may be modified to fit the budgetary estimates based on the detailed construction estimate.

For large capital reliability improvement projects, after the design is finalized, UPPCO determines the labor and equipment resources needed to complete the project within expected timelines. The first factor is whether the job is overhead or underground. UPPCO crews typically complete overhead work while underground installation work is completed by qualified contractor crews.

UPPCO utilizes a competitive bid process to select an underground installation contractor under a “blanket” contract typically for a 3-year period. UPPCO’s detailed bid specification is provided to a number of contractors that have experience with the installation of electric utility underground cable, conduit, and surface-mounted equipment. Ten prospective contractors were invited to UPPCO’s last *underground blanket contract pre-bid meeting*; seven attended with six of them providing bids.

Bids are rigorously evaluated on a payline (i.e. task) basis using historical quantities of the various tasks performed. Tasks may include trenching, plowing, boring and rock sawing, installation of cable and conduit, and setting underground equipment, such as pad-mounted transformers and fuse pads, junction enclosures, and partial pole risers, among a host of lesser used paylines to determine the best value for UPPCO and its customers.

The blanket contract covers typical underground work, which is primarily comprised of customer-requested work, such as line extensions, service installations, and facility relocations, and to a lesser extent, smaller company-identified underground projects, like aged cable replacements and relocations. Larger underground projects with an estimated contractor cost of \$100,000 or more may be bid out to other qualified contractors at UPPCO’s discretion to ensure the project is completed in the most cost-effective manner.

For large overhead projects, such as storm hardening an existing overhead line, UPPCO reviews the current and expected upcoming workload to determine if the project can be completed using UPPCO resources. If it is deemed that company crews cannot complete the overhead project, the work is typically bid out to contractors experienced in such work. The bid award is based both on bid cost and the availability of the contractor to complete the work within the expected project timeline.

Therefore, for specific, large CapEx projects, these actions allow UPPCO to balance company resources against known and expected workload to yield the maximum value for UPPCO customers ensuring affordability while also improving reliability.



## **Performance Monitoring / Project Adjustments**

Both ongoing performance monitoring and project adjustments that must be made mid-project also impact UPPCO's planning to maintain and enhance the reliability of its distribution system.

### **Performance Monitoring**

Regular monitoring of UPPCO's distribution assets is a crucial input in the development of UPPCO's plans to maintain and increase reliability. UPPCO performs overhead inspections on a 12-year cycle and underground inspections on a 6-year cycle. The inspection cycles provide a regular, routine field review of UPPCO's entire distribution system by an independent third party. The inspection process is completed with reports that are prepared by the third party to UPPCO's detailed specifications at the conclusion of the inspection.

During the normal course of routine work, UPPCO field crews also identify system issues between inspection cycles, which Distribution Engineering review to address the issue. Routine work such as response to trouble calls, line patrol, or design work also provides opportunities to identify potential system condition issues between inspection cycles.

On a wider scope, UPPCO uses Outage Management System (OMS) data and reliability metrics to monitor the performance of the distribution system and identify any potential issues. UPPCO performs a number of reviews over the course of the year to monitor performance of the distribution system, specifically:

1. Weekly – Review of OMS outage data to address larger scale outages for accuracy and correct OMS data as appropriate.
2. Monthly – Review of wires down responses, 15-day new service installations, worst feeders, line clearance progress, outage credits, reliability metrics, and major storm data. While much of this data is required for MPSC reporting, some data is also used internally.
3. Annually – Review of the worst feeder listing for the past year, which is also required for MPSC reporting, but as mentioned previously, UPPCO typically completes a worst feeder analysis for a 3-year period to help identify areas most in need of reliability improvement and therefore direct additional capital expenditures.

### **Project Adjustment**

Adjustments that are made during maintenance (and other) projects also impact UPPCO's maintenance decisions. As mentioned in the previous section, projects are typically budgeted based on a high-level estimate. Project scopes may be occasionally modified when the detailed, final estimate is completed prior to construction. Projects may also be adjusted based on current material and resource cost and availability at the time construction work is being planned.



Ongoing adjustments are also made based on UPPCO's ability to complete projects using its own staff. UPPCO currently contracts out all underground installation projects. Large underground maintenance projects may be bid out and therefore could impact project costing and scope. Typically, overhead project work is completed by UPPCO line crews. However, large overhead projects may be bid out if it is determined that UPPCO crews cannot complete the project due to other workload. These bids may impact project costing and scope prior to construction.

During construction, UPPCO monitors project construction progress. Occasionally, adjustments must also be made mid-project that impact the scope and cost of projects. For example, unforeseen underground encumbrances or a permitting issue can result in changes in project scope. Although such issues are not common, any issues that arise are discussed between Distribution Operations and Distribution Engineering to determine a course of action. This action may require an adjustment to the scope, or to the budget. If the budget requires adjustment, other projects may be impacted and adjusted as well.



# UPPCO Five-Year Distribution Plan

## Overview

UPPCO’s distribution projects have historically had a focus on ensuring Michigan Public Service Commission (“MPSC”) compliance for distribution system adequacy, safety, and proper voltage levels. These projects have had varying scopes due to the dynamic nature of the distribution system’s integrity and developments in the distribution system’s load profile that have been driven by changing customer demographics over time.

With increasing customer expectations along with the MPSC’s Distribution Performance Measures requirements, more emphasis is being placed on reliability improvement and faster storm restoration. Therefore, in addition to projects necessary for safety, compliance, voltage, or system loading issues, the selection of specific reliability-based projects is often determined using a combination of:

1. Severity of the outage data at a given location
2. Age and condition of the existing distribution facilities
3. Availability of capital resources
4. Number of customers benefiting
5. Logistical considerations, such as:
  - a. Design complexity
  - b. Constraints due to access, right-of-way, easements, and permitting
  - c. Weather
  - d. Material, labor, and contractor resource availability

UPPCO’s efforts to maintain and improve the reliability of its distributions system will focus on storm hardening projects, asset renewal projects, and the inspection and maintenance of the distribution system and substations. Each of these efforts are discussed in more detail below.

For typical distribution reinforcement projects, UPPCO has a 5-year budget horizon. Each year upcoming project designs are typically reviewed and may be modified prior to design finalization due to any potential issues such as easements, permits, resource availability, material lead times, landscape, and customer demographic changes.

While UPPCO tries to plan these projects in advance, it must adjust its plans for distribution reliability projects as conditions require. If any issues arise during the review process, alternative project options are considered that would still provide similar benefits. Project scopes may be adjusted based on this review, or other higher priority projects may have been uncovered since the last review, and these projects may be reprioritized within a budget year, or even within the 5-year budget horizon as system conditions evolve from year to year.



## **Storm Hardening**

Storm hardening of the distribution system, through various methods, is one of the primary ways that UPPCO plans to maintain and increase the reliability of its distribution system. UPPCO's storm hardening efforts are a systematic and efficient approach designed to improve reliability over time. Targeted projects on UPPCO's worst feeders will improve customer satisfaction, reduce the number and duration of outages, make UPPCO's distribution more resilient during storms, and move UPPCO closer to the State's goals to reduce the number and duration of outages and improve the customer experience.

UPPCO's storm hardening practices include:

1. Line Clearance/Vegetation Management
2. Overhead Inspection Program
3. Underground Inspection Program
4. Strategic Undergrounding
5. Replace Existing Poles with Taller or Stronger Poles
6. Effective Shared Facilities Program
7. Enhance Restoration Process
8. Optimize Technology

### **Line Clearance/Vegetation Management**

UPPCO's 6-year cycle approach is adequate to maintain system reliability in a typical healthy forest taking into account tree growth and canopy spread over the years. Maintaining an effective on-cycle line clearance program reduces potential outages caused by falling trees, but also provides crews with good accessibility to locate and restore service in a timely manner. Additionally, a line clearance process that is on-cycle avoids future costs to reclaim overgrown right-of-way ("ROW"); that is, UPPCO experience shows that maintaining a line clearance program on-cycle is less costly in the long run than reclaiming a ROW when an overhead distribution system becomes overgrown due to cycle slippage or neglect.

Line clearance and vegetation is one of the most impactful ways that UPPCO improves the reliability of its distribution system, and these practices are the cornerstone of UPPCO's plans to improve reliability. Strong winds are predominantly the cause of tree-related outages, and most tree-related outages in the last few years are due to off-road right-of-way trees falling onto the line, not from trees growing into the line or from dead trees just falling over. While the weather is quite unpredictable and uncontrollable, a systematic line clearance program can greatly aid in both reducing the number of tree-related outages and in improving the utility's ability to respond to and restore the system in a timely manner.

These lines must be trimmed on a regular basis in order to provide a safe and reliable electrical distribution system for the Company's customers and the general public. UPPCO also clears ROW to ensure enough access to restore service in the event of a weather or non-weather-related outage. UPPCO has approximately 2,200 miles of overhead primary conductor ROW. The overhead primary system is divided into project areas. UPPCO's line clearance project areas map is included as Appendix 3a.



Each year project areas are selected for trimming based on the date of the previous trim. To maintain UPPCO’s line clearance program on-cycle, UPPCO sets an internal goal to trim a minimum of 372 miles per year. Occasionally, some project areas carry over into the following year. Conversely, projects may be pulled from the next cycle year into the current or next planned cycle year to make sure that the goal of trimming 372 miles is met. Projects are also pushed or pulled from one cycle year to another to efficiently plan line clearance work around spring road restrictions or to take advantage of line clearance crew location and proximity to the upcoming project areas.

As displayed in Appendix 1, Table 7, *Line Clearance History*, UPPCO has cleared the following line miles over the past five years:

<u>Year</u>	<u>Miles</u>	<u>Cost/Mile</u>
2019	375	\$4,981
2020	382	\$6,218
2021	376	\$7,650
2022	375	\$7,993
2023	377	\$8,506

UPPCO also completes vegetation management of selected underground rights-of-way in rural areas that are becoming unidentifiable and inaccessible for operation and maintenance.

UPPCO’s tentative 5-year line clearance schedule is shown in Appendix 3b. As mentioned above, some project areas in the current year may carry-over into the upcoming cycle year and the line clearance program is actively managed to ensure the clearance mileage target is met.

As discussed above, the management of the vegetation in proximity to the distribution system is now on-cycle. UPPCO intends to continue its 6-year vegetation management program and aims to trim no less than 372 line-miles per year.

UPPCO has strict standards for its line clearance and vegetation management projects. When UPPCO seeks competitive bids, it details specifications for line clearance that its contractors must follow. The specification includes the identification and removal of hazard trees located off the normal utility clearance ROW which may pose an imminent danger to the system. UPPCO’s line clearance processes have been improving for many years, and the Company has completed its previously approved accelerated line clearance project from 2014 to 2017. With the completion of this accelerated program, the Company now maintains a 6-year cycle for its system.

UPPCO’s 6-year clearance cycle is meant to prevent tree branches from growing such that they can make direct contact with conductors. UPPCO’s experience has shown that a 6-year clearance schedule is adequate in most cases. A longer frequency between clearance cycles results in more work being necessary to access and trim the ROW. Each year that a section of the line goes beyond the 6-year cycle, additional tree growth increases the likelihood of more frequent line contact with tree branches, which can cause momentary and/or sustained outages. Prior to 2018, when line clearance of UPPCO’s distribution system was operating on a longer than 6-year cycle, UPPCO’s experience indicated that trimming costs increased significantly the longer a line went without having nearby trees trimmed.

Trained and experienced contractors, as well as the UPPCO Line Clearance Coordinator, have the ability to identify trees that have become hazards to the distribution system. Tree diseases, caused by



infestations by the Spruce Bud Worm and the Emerald Ash Borer, as well as Beech Tree Disease, and Oak Wilt, have become prominent in UPPCO service territory and have significantly impacted the line clearance program. UPPCO's experience indicates that the cost to address areas where dead and dying trees are present is approximately double the cost of an area without dead and dying trees. Additional costs include extensive tree removals, contact and negotiation with customers and landowners for off ROW trees, as well disposal of the large amount of tree debris caused by the removals.

As indicated above, line clearance costs overall have increased due to several factors. First, as described above, the cost increases are partially due to the higher cost associated with the drastic increase in tree mortality of off ROW trees, which UPPCO refers to as "hazard" or "danger" trees. When "hazard" or "danger" trees are present, the contractor often incurs increased travel expense in order to investigate both customer and company tree removal requests that occur both in and out of the planned cycle trim areas in order to determine the severity of the situation, the impact to the system, public safety, and the increased risk of fire danger. These processes often require additional negotiation with customers and landowners to obtain permission to cut these danger trees, and in some instances, to remove the associated debris caused by their removal. As a result, line clearance expenses are projected to increase annually.

Furthermore, an increase in fuel prices over the last several years has caused additional contractor expenses due to the vast amount of service territory that needs to be traversed to complete the annual line clearance miles necessary to remain on-cycle. To help manage this and provide appropriate transparency in this specific cost area, UPPCO has initiated a Diesel Fuel Escalation Policy to help provide a mechanism whereby a positive or negative adjustment to the contract base rate will be implemented, which is tied to set values and benchmarked against published values for the "Retail On-Highway Diesel Prices" in the Midwest region, as published on the U.S. Energy Information Administration website ([https://www.eia.gov/dnav/pet/pet\\_pri\\_gnd\\_dcus\\_r20\\_m.htm](https://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_r20_m.htm)). This is intended to keep any contractor price increase that is related to fuel prices from being lost in contractor base rates, or not addressed at all, which could impact the viability of the contractor's operations, while also automatically reducing UPPCO costs as fuel prices decrease.

In order to maximize the cost effectiveness of the Company's line clearance program, UPPCO relies upon two qualified utility line clearance contractors. This provides UPPCO with the means to maintain competitive pricing when soliciting pricing quotes by comparing production and pricing performance over a variety of service locations, and ROW, geographic, and environmental conditions. UPPCO also leverages this information to achieve a performance-based assignment of the various cycle project areas that make up the Company's 6-year line clearance cycle.

The majority of UPPCO's distribution system lies within county road ROWs that provide limited ROW for clearance. UPPCO's current utility ROW only extends 10 feet beyond the edge of the conductor. As such, even when line clearance is performed to specifications, a 70-foot tree growing off the ROW can still easily fall into a pole line located 35 feet above ground.

Consequently, private easements or permissions from private property owners must be secured for line clearance activities beyond this boundary. Regular trimming is crucial because many of native tree species are in excess of 70-feet tall and in relatively close proximity to lines. In fact, any tree 40-feet tall or larger could contact a line 35 feet above ground. As evidenced by the picture below, it doesn't take a very large off-right-of-way tree to cause an outage.



*Off-right-of-way tree*



*Healthy off-right-of-way tree towering over/falling into electric line*



## Overhead Inspection Program

UPPCO's overhead line inspection program is another crucial part of its Distribution Plan to maintain and improve the reliability of the distribution system. UPPCO implements a comprehensive overhead facilities inspection and treatment program. Through the use of a 12-year inspection cycle, UPPCO reviews both foreign-owned poles as well as those that are self-owned. Replacement of poles in poor condition and the treating of ground lines on otherwise sound poles eliminates potential issues before they occur and impact reliability.

UPPCO's overhead inspection includes the identification of potential NESC clearance issues.

The overhead line inspection program is used to provide quick fixes to smaller issues and identify larger issues that require more work. Some smaller issues are identified and repaired during the inspection process, such as pole treatment at the ground line, repairing ground wires, and installing guy markers. Poles with larger issues are identified as "danger and reject" poles and are scheduled for replacement within a year after the inspection results are received. Additionally, "danger and reject" poles are identified with a tag to alert line crews of the pole's degradation so safety measures can be taken.

"Danger and reject" make up a small percentage of the issues identified through the overhead inspection program. From 2019 to 2023, an average of 1.5% of the inspected poles were classified as "danger and reject" poles. This percentage has been generally trending downward as a result of UPPCO's continued pole inspection practices over the years. A record of UPPCO's pole inspections is provided in Appendix 1 Table 8, *2019 – 2023 Pole Inspection History*. As shown in this table, the 5-year average cost for the professional overhead system inspection and pole treatment was approximately \$175,666 per year or roughly \$29 per pole.

UPPCO's 12-year cyclic overhead inspection program is a prudent and cost-effective maintenance process. UPPCO will continue this program because it benefits both UPPCO customers and the general public by identifying overhead assets in poor condition and other potential issues that can be addressed before they become outages that negatively impact system reliability or a risk to the public.

## Underground Inspection Program

Like its overhead inspection program, UPPCO's underground line inspection program plays a key role in its distribution planning and maintenance. UPPCO implements an underground inspection program on a 6-year cycle to identify equipment that is in poor condition, undermined or tilting before these conditions trigger outages, or safety issues that could pose a hazard to employees or the general public.

The underground inspection program consists of visual inspections of the physical components of the existing underground system on a 6-year cycle. Some items are identified and repaired during the inspection process, such as treating for ants, clearing vegetation, re-leveling, filling gaps in the ground surface, and painting as well as minor grounding and bonding. UPPCO also inspects all newly installed underground facilities during the following construction season after the facilities were put in the ground.

A record of UPPCO's underground inspection history is described in Appendix 1, Table 9, *2019 – 2023 Underground Inspection History*. As seen in this table, the 5-year average cost for the professional underground system inspection was approximately \$70,308 or roughly \$51 per cabinet. Additionally, an



average of 113 cabinets were refinished over this period, extending the life of these assets, at a cost of \$ 38,536, or roughly \$341 per cabinet.

UPPCO's 6-year cyclic underground inspection program is a prudent and cost-effective maintenance process that improves reliability. UPPCO will continue this program because it benefits both UPPCO customers and the general public by identifying underground equipment in poor condition and other potential issues that can be addressed before they become outages or a risk to the public.



## Strategic Undergrounding

Selective rerouting of overhead lines to underground in areas with a high tree density, prone to frequent tree/storm related outages, and/or limited accessibility is another manner in which to improve system reliability. Most of UPPCO's service territory is rural and more rural areas require more attention to improve reliability. The more rural and lengthy feeders are typically the company's worst feeders with respect to SAIDI and SAIFI, and therefore, they are typically selected for reliability improvement investment.

## Selection

The costs and benefits of overhead or underground installations are assessed by Distribution Engineering prior to the initiation of any CapEx project based on the geography of the existing line, such as line route and ground conditions as well as initial capital costs and on-going operations and maintenance ("O&M") costs. Strategic undergrounding projects are capital intensive and therefore only the worst areas are targeted for rerouting. Replacement of overhead lines with underground provides value to UPPCO customers in several ways, which are discussed below.

## Outage Reduction

UPPCO's underground lines are much more reliable than overhead lines. UPPCO's OMS tracks causes and devices in outage data, including events involving underground distribution equipment failures. Appendix 1 Table 10, *Underground Outage History Compared to All Outages*, shows the number and impact of underground related events. UPPCO experiences very few underground dig-ins and equipment failures, such as padmount transformer and underground cable failures. The data in the table includes events that involve, or serve, underground facilities. Some of these events involve overhead facilities that feed the underground system, such as an animal causing the riser fuse to operate or an arrester failure on the riser.

The data in Table 10 demonstrate that, even including events that are not strictly caused by failure of UPPCO's underground system, the impact to UPPCO's customers by the failure of underground lines is an order of magnitude less than all other events in terms of SAIDI, SAIFI, and the number of customers affected. For all outage events, excluding transmission-caused, over the period of 2019-2023, UPPCO experienced nearly 10,000 events affecting more than half a million customers over the 5-year period resulting in a SAIDI of 2,227 minutes and a SAIFI of 9.2 events. Outages involving underground facilities accounted for only 492 of those events, affecting 1,909 customers, resulting in a SAIDI of 4.73 minutes, and a SAIFI of 0.0325 events.

Events involving underground facilities comprised less than 5% of UPPCO's total outage events, but those events affected less than 0.5% of all customers who experienced outages over the 5-year period. Those events also resulted in less than five (5) SAIDI minutes of the 2,227 total SAIDI minutes affecting all customers.

Thus, the data clearly indicates reliability is significantly better for customers served by underground systems compared to those served by overhead.



## Reduced Maintenance Cost

Strategic undergrounding of lines when appropriate also leads to reduced maintenance costs. As indicated in the previously discussed Table 1 in Appendix 1, *Distribution System & Asset Information*, of UPPCO's total of 4,518 line miles, the underground system consists of approximately 1,232 line miles or 27% of the total electric line miles.<sup>3</sup> Appendix 1, Table 11, *Historical Maintenance Costs*, documents UPPCO's overhead and underground maintenance costs from 2019 through 2023.

UPPCO's average underground maintenance cost for calendar years 2019 through 2023 was only 8% of UPPCO's total cost to maintain the distribution systems, but more significantly on a per mile basis, underground maintenance costs averaged only \$509 per mile compared to overhead at about \$2,119 per mile.

Overhead and underground maintenance include such activities as:

- Trouble calls/Callouts
- Outage/Storm Restoration
- Line Clearance Activity
- Inspection Programs
- Locating
- Asset Refurbishment

Line clearance is nearly 100% attributable to the overhead system and locating and asset refurbishment are attributable to the underground system. The other maintenance activities are attributable to either the overhead or underground system as the situation at hand requires.

## **Effective and Prudent Capital Investment**

Strategic undergrounding can be the most cost-effective and prudent method to improve reliability. As previously discussed in the Project Costing section of the Prioritization Methodology, UPPCO creates high-level budgetary estimates as part of its project selection process. The calculations that create the by-foot budgetary estimates take into account initial capital investment as well as ongoing maintenance costs.<sup>4</sup> The results of this calculation provide a quick method to compare the cost of rebuilding an existing overhead line as underground line versus rebuilding and hardening the existing line and maintaining the line as overhead. The calculation uses current cost levels for materials, underground contractors, UPPCO labor and equipment, line clearance, and maintenance. Maintenance includes an inflationary factor. As discussed above, underground projects have more variability due to unknown sub-surface obstructions and potential permitting issues that may impact project costs, therefore, UPPCO creates a range of by-foot costs for underground.

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<sup>3</sup> Note, the overhead and underground miles are a snapshot in time from UPPCO's GIS system. Also note that line mile data for 2020 was not available, and therefore, was simply shown as an average of 2019 and 2021 line-miles.

<sup>4</sup> These cost calculations are available in Appendix 2, Table 1, *By-Foot Estimate Capital Investment Cost Calculation*.



Reference Appendix 2, Table 1, *By-Foot Estimate Capital Investment Cost Calculation*. The results of this calculation provide a quick method to compare the cost of rebuilding an existing overhead line as underground versus rebuilding and hardening the existing line and maintaining the line as overhead.

Single-phase strategic undergrounding is clearly the least-cost option using a modest inflationary factor of 1%. Undergrounding projects cost about half as much as rebuilding overhead. For three-phase lines, the complexity of the undergrounding option makes the comparison less clear. Three-phase overhead costs are roughly in the middle of the estimated underground cost range. However, using a still conservative inflationary factor of 1.5% makes even the high range cost of underground about the same as overhead. Moving the inflationary factor to 2% results in three-phase underground being the least-cost option based on current project costing methodology and the current cost of materials, labor, equipment, and contractors.

### **Intrinsic Value & Customer Savings**

Beyond cost savings, strategic undergrounding has many other benefits. The increased customer value discussed above does not account for other savings, such as the expected reduction in repetitive outage credits to customers, nor does it account for the intrinsic value of customer satisfaction in the decreased number of outages.

There has been much debate over the cost of outages to customers and a definitive and industry-accepted method has yet to be created. In MPSC Case No. U-20629, the Citizens Utility Board suggested that outages may cost the average customer \$3-4 per hour. Although UPPCO does not agree with this assertion, reducing the number and duration of outages will certainly reduce outage costs to customers.

Furthermore, UPPCO's 5-year Average SAIDI, including MEDs, which is reported in Appendix 1 Table 10, *Underground Outage History Compared to All Outages* was 445.5 minutes, or 7.4 hours, per customer per year for all outages, but averaged less than 1 min, or 0.016 hours, per customer per year for underground-related events. Therefore, there are clearly unquantified savings for UPPCO customers connected to strategic undergrounding, since they are avoiding costs as a result of reduced outages.

### **Improved Safety**

Strategic undergrounding projects will also lead to safety benefits. UPPCO experiences very few safety-related events involving its underground system. For the 5-year period of 2019-2023, nearly 540,000 customers experienced outages, and of those, less than 2,000 customers were affected by outages involving underground as shown in Appendix 1 Table 10, *Underground Outage History Compared to All Outages*. Events caused by the public, such as vehicle accidents and dig-ins, accounted for outages to about 31,000 UPPCO customers as shown in Appendix 1, Table 4a, *Outages by Cause*. Appendix 1, Table 10 also shows that only 341 customers experienced outages due to dig-ins into UPPCO's underground system. These data generally indicate underground infrastructure is inherently safer and more reliable than overhead due to the fact that there is significantly less exposure to the public and the elements.

Furthermore, UPPCO responds to MISS DIG locate requests to mitigate the risk of inadvertent contact with buried electrical infrastructure and routinely issues public safety messaging through various media sources to assist the public in identifying and mitigating the hazards of coming into contact with underground electrical infrastructure.



## **Overall Costs**

When selecting strategic undergrounding projects, UPPCO takes potential costs into account, especially because undergrounding projects can vary significantly in cost due to various factors such as complexity, ground conditions, ROW availability, access, easements, brushing/line clearance, municipal and/or environmental permitting, customer density, and even customer acceptance. Strategic undergrounding projects have different levels of return based on the length of line, number of customers served, and complexity of the project. For the reasons discussed above, and to reduce overall system maintenance costs, UPPCO endeavors to replace more aged overhead infrastructure with underground cable and equipment as surface and conditions allow and at a reasonable cost to achieve an expected reliability improvement.

## **Overhead Line Hardening**

Overhead line hardening is another important component in UPPCO's distribution plans. Generally, overhead line hardening includes continued line clearance cycle trimming, replacement of aged wood poles with Class-3 poles, replacement of old copper conductor with ACSR conductor, and rerouting lines, if deemed conducive to the objectives of a project.

Replacing existing poles with taller and stronger poles is also an effective system hardening process. (UPPCO has standardized Class-3 poles for new overhead line construction.) Not only can the taller height often help to avoid tree-related outages altogether, but the increased strength can also help to prevent the pole from breaking if a tree does fall on the line. Broken poles, especially during storm conditions, take significantly more time to replace than fixing a broken conductor or removing a tree from the line, so installing stronger and taller poles strengthens the distribution system and reduces both the duration and frequency of outages.

Typically, when a section of existing overhead line is designated to remain overhead, the overhead conductor will also be replaced with the current standard conductor based on the existing and expected future load on the line. The Copper Conductor Replacement program is discussed more below.

## **Effective Shared Facilities Program**

UPPCO also uses its shared facilities program to maintain the reliability of its distribution system. The protocols of this program serve an important role in UPPCO's distribution maintenance and planning. The purpose of UPPCO's shared facilities program is to ensure that foreign attachments are accounted for and included in pole loading calculations. Also, when new attachments are requested, UPPCO uses that as an opportunity to bring existing facilities up to current NESC and Company standards.

UPPCO requires an attachment agreement with all potential pole attaching companies. In addition, requests for new attachments must be accompanied by a certified engineering analysis of the existing poles, conductors, and anchor points. These studies are then reviewed by UPPCO Engineering, and all NESC clearance violations and pole strength issues must be corrected at the attaching party's expense prior to any new attachments being made.

Pole space sharing is a requirement of state and federal law, and UPPCO will continue to improve the overall strength of the distribution system through review of shared facilities attachment requests and the subsequent make-ready work.



## **Enhanced Restoration Process**

Enhanced restoration processes also serve an important role in UPPCO's distribution planning as a way to improve reliability. UPPCO's restoration process is enhanced by increasing the ability for crews to identify, locate, and access the outage location, and by increasing the flexibility of the system for the crews to restore service. While these practices do not necessarily eliminate outage events, they make the system more resilient when outages do occur. Several of the practices already mentioned help crews to better access outage locations, such as continuing the line clearance program and rerouting overhead lines to underground.

The enhanced restoration process program also includes rerouting cross-country lines to road ROWs to make the system more accessible to crews. Early design practice was to run distribution systems via the most direct route to save on cost and effort to get service to outlying areas. Over time, however, access points can be overrun with vegetation, creating obstacles to utility crews in identifying and accessing outage locations and to making necessary repairs.

UPPCO also sees significant value and places a higher priority on projects that include rerouting overhead off-ROW lines to an on-ROW underground system, which improves reliability and reduces future maintenance costs. Additionally, these projects increase accessibility, reduce line clearance requirements, and allow UPPCO's line crews to more efficiently patrol the system and locate outage causes.

In some cases, the UPPCO may also add switching capability to increase the flexibility of the distribution system and improve restoration work during outages. Due to UPPCO's rural service territory, creating networks or loops within the distribution system can be impractical on a large scale due to the nature of long circuits outside of urban areas. However, closing a gap in a rural distribution system where pockets of higher customer densities exist allows crews to open the system as near as possible to the outage, then close a normally open point to restore power to customers that otherwise would experience an outage until the system can be repaired. The practice of switching to partially restore service significantly reduces the duration of the outage and improves SAIDI metrics and is taken into consideration during line relocation projects.

## **Optimize Technology**

Technological solutions are also considered by UPPCO when it is planning for upcoming reliability improvement projects. UPPCO optimizes distribution technology in several forms which are discussed later in the Grid Modernization section.



## **Asset Renewals**

Asset renewals are another cornerstone of UPPCO's distribution reliability plan.

### **Overhead**

#### **Pole Replacements**

Poles are typically identified for replacement during the pole inspection process. However, poles may also be replaced during the design phase of new customer line extensions, new service installations, shared facility attachment requests, or other routine work.

For example, a pole selected for a new underground riser, new transformer, or recloser setting requiring additional clearances to meet current standards will be designed for replacement during the project. On other occasions, a pole may be identified for replacement during routine work between inspection cycles that was found to be damaged by a snowplow or animals, or otherwise approaching end of its usable life.

As mentioned above, UPPCO has standardized on Class-3 poles for overhead primary construction, which strengthens the overhead system overall. Although UPPCO will continue to install Class-5 poles for overhead guy and secondary poles, or as deemed appropriate in other situations, to deplete existing stock.

#### **Line Rebuilds**

Line rebuilds are typically completed to address areas with reliability issues, capacity limitations, or aged infrastructure. This program also includes rerouting cross-country lines to road ROWs to make the system more accessible to crews. Early design practice was to run distribution systems via the most direct route to save on cost and effort to get service to outlying areas. Over time, however, access points can be overrun with vegetation, creating obstacles to utility crews in identifying and accessing outage locations and to making necessary repairs.

UPPCO's strategy was discussed in its August response in Case No. U-21122 to the Commission's questions regarding back-lot versus front-lot construction and maintenance costs. UPPCO sees significant value in reliability improvement and reduction in future maintenance costs of moving overhead off-ROW lines to an on-ROW underground system. These projects are capital-intensive and require planning and budgeting; therefore, these projects are strategically targeted and weighed against other potential reliability improvement projects and prioritized accordingly.

#### **Porcelain Cutout Replacement Program**

UPPCO's Porcelain Cutout Replacement Program is another important part of its overhead asset renewal strategy. As shown in Appendix 1, Table 4b, *Distribution Equipment Outages*, cutout failures have been UPPCO's leading cause of distribution equipment related outages in terms of SAIDI and in the number of customers affected. UPPCO has over 22,600 pole locations with cutouts and approximately 12,000 locations have been upgraded to polymer cutouts.



UPPCO believes that hairline cracks in the porcelain allow the intrusion of water that may result in cyclic freeze and thaw conditions within the porcelain that eventually results in porcelain breakage and an outage. The cutout pictures below indicate such a hairline fracture. The fracture is difficult to see in the picture to the left but more obvious in close-up picture on the right. Therefore, hairline fractures are nearly impossible to identify from the ground during routine inspections.



*Porcelain cutout removed from the field*

UPPCO began experiencing frequent porcelain cutout failures in 2013. UPPCO’s parent company, at the time, sent samples to S&C Electric Company for examination. Initially, S&C Electric Company believed the failures were only related to 2006-2007 vintage cutouts, but UPPCO subsequently experienced failing cutouts of other years of manufacture as well.

UPPCO was informed by the manufacturer that the failing cutouts were not covered by any warranties and documentation from the vendor only indicated a limited 2-year warranty from the date of shipment.

UPPCO’s OMS records indicate the number of outage events caused by broken cutouts as follows:

<u>Year</u>	<u>Number of Cutout Failures</u>
2019	203
2020	222
2021	160
2022	154
2023	147

The following data indicates the number of cutouts UPPCO has replaced from 2021-2023 and the forecast quantities for 2024 and 2025:



<u>Year</u>	<u>Number of Cutouts Replaced</u>
2021	1,844
2022	2,822
2023	2,777
2024	1,875 (approx./forecasted)
2025+	2,250 (approx./forecasted)

Barring any significant changes to current funding levels for this program, UPPCO’s goal is to have all porcelain cutouts removed from the system by the end 2030.

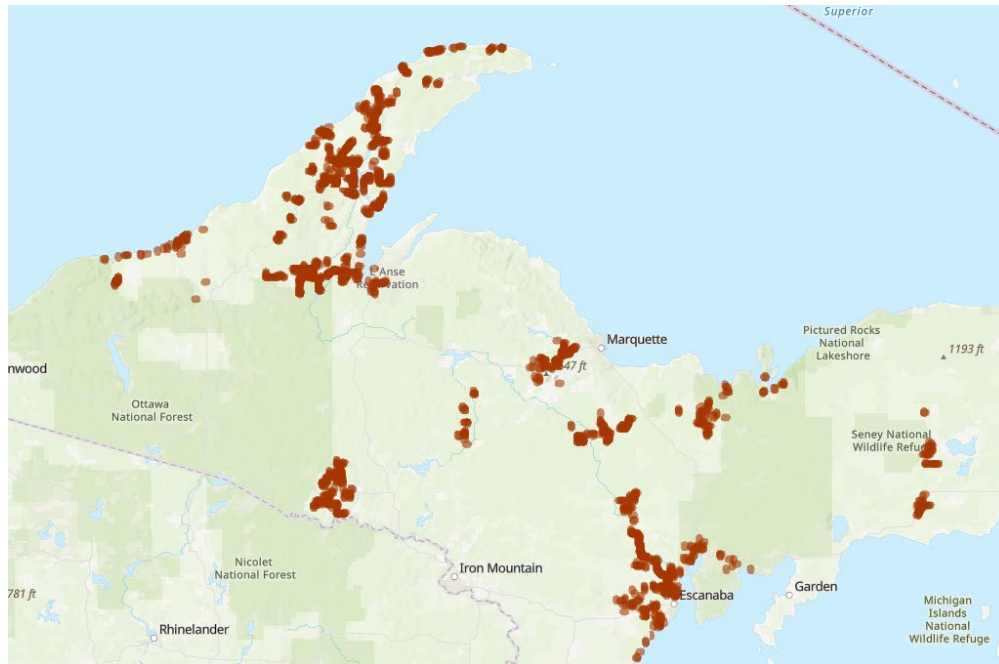
### Copper Conductor Replacement Program

UPPCO’s Copper Conductor Replacement Program is also a key part of its asset renewal program. About 383 circuit-miles of UPPCO’s 2,170 total overhead primary circuit-miles is comprised of copper or copperweld conductor. Copper conductor indicates very old construction methods. These conductors were likely installed in the 1940s-1950s. Copper conductor tends to become brittle with age as a result of being stretched and damaged by fallen trees, snow load, galloping, and corrosion. Therefore, as copper wire ages, it does not withstand storm and tree-related outages as well as ACSR.

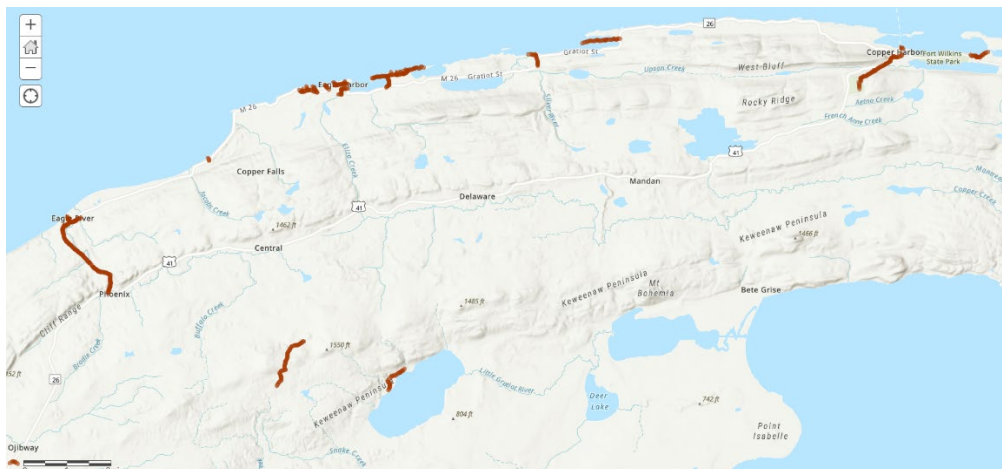
Due to age and their weakened state over time, copper distribution lines are targeted for replacement through the CapEx project planning and prioritization process with underground cables or replaced with ACSR and hardened for overhead use.

UPPCO’s GIS Department created a map layer to indicate where spans of copper conductor remain within UPPCO’s overhead distribution system. Distribution Engineering uses these maps to help identify good locations for capital investment projects that would have a twofold effect – update or replace aged facilities and to improve reliability.

The GIS maps below indicate locations where copper conductor currently exist. The first map indicates UPPCO’s entire service territory, and the second map is a zoomed-in section at the northern end of the Keweenaw Peninsula.



*Copper conductor in GIS within UPPCO's entire service territory*



*Zoomed-in area indicating copper conductor in the northern end of the Keweenaw Peninsula*

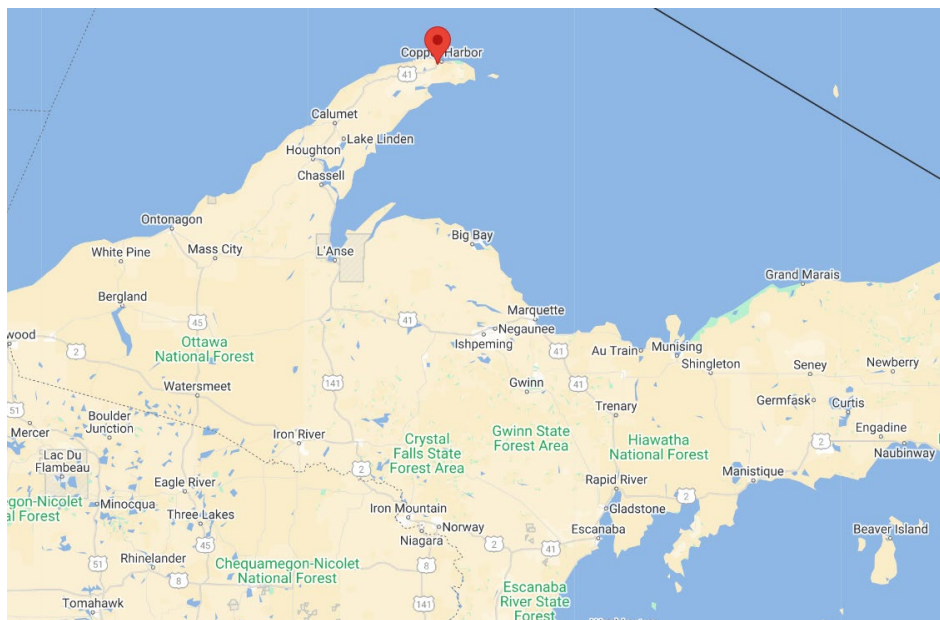
### Street and Yard Lighting

UPPCO has nearly 8,300 lighting installations throughout its service territory. Of these, more than 98% have been converted to LED.

In 2018, UPPCO began a systematic approach to upgrade street and yard lighting from high pressure sodium bulbs to LEDs. Prior to the LED conversion project, UPPCO followed a 5-year outdoor lighting (“ODL”) program to replace bulbs and photoelectric eyes. UPPCO typically installed a cobra head light for street lighting and a power bracket style light for yard lighting. The cobra head and power bracket fixtures make up the vast majority of UPPCO lighting types, but flood and shoe box light fixtures were also converted to LED during this program. UPPCO had very little decorative lighting installations which were handled on a case-by-case basis.

Distribution Engineering performed an analysis of different manufactures’ specifications, warranties, and costs. A primary manufacturer was selected for the different LED fixtures along with a secondary manufacturer and Engineering worked with UPPCO’s Regulatory Affairs Department to develop new rates for the various LED lighting types. The LED fixtures and photo eyes have an expected life expectancy of 100,000 hours or about 20 years.

The new LED cobra head and power bracket light fixtures are cut-off style thereby directing the light downward only, which helps to light the intended area and to reduce light pollution. At this time, UPPCO is not aware of any municipalities with “dark sky” policies or ordinances. However, one location within UPPCO’s service territory was designated an International Dark Sky Park in 2022 - the Keweenaw Mountain Lodge near the tip of the Keweenaw Peninsula. Refer to the map below from [Dark Sky Place finder | DarkSky International](#) indicating the location of the dark sky park near Copper Harbor.



*Keweenaw Dark Sky Park Location, Keweenaw Mountain Lodge | Source: <https://darksky.org/places/keweenaw-michigan-dark-sky-park/>*

Small changes in technology continue each year and are reviewed annually for inventory replacements. Just in the few years of this program, a 100W equivalent cobra head energy demand has been reduced from 48W to 42W.

Other than new installations, UPPCO does not anticipate any significant changes, upgrades, or wholesale replacements of outdoor lighting within the 5-year budget horizon.

### **Underground Replacement Plan**

UPPCO’s Underground Replacement Plans, which are flexible so as to allow for needed replacements when issues arise, are also an important part of its asset renewal programs. As discussed above, much of UPPCO’s underground cable was installed in the 1970’s with 175 mil insulation and a bare concentric neutral, which is more prone to faults. UPPCO has test equipment to locate failed underground cable



and fault locations are mapped and tracked in UPPCO's GIS to provide distribution engineers data which may be used to justify a future cable replacement project.

When a fault does occur on a radial underground distribution line, repairs are typically made to restore service at that time; however, in some cases, if the conditions permit, the line is temporarily by-passed to restore service, which allows Engineering to review the faulted area. If the line is looped, then often the crew will switch the feed to restore power and leave the failed section of cable temporarily out of service. This provides time for Engineering to review the system and determine if the cable section or multiple sections should be replaced, rather than repaired, based on age of the cable and the number of previous failures.

UPPCO anticipates annual replacement of underground cables due to failure and includes a budget item to allow for these replacements over the course of the year. This provides flexibility to perform opportune cable replacements with a short turnaround time to improve the reliability of the system serving impacted customers.

### **Transformer Replacement Program**

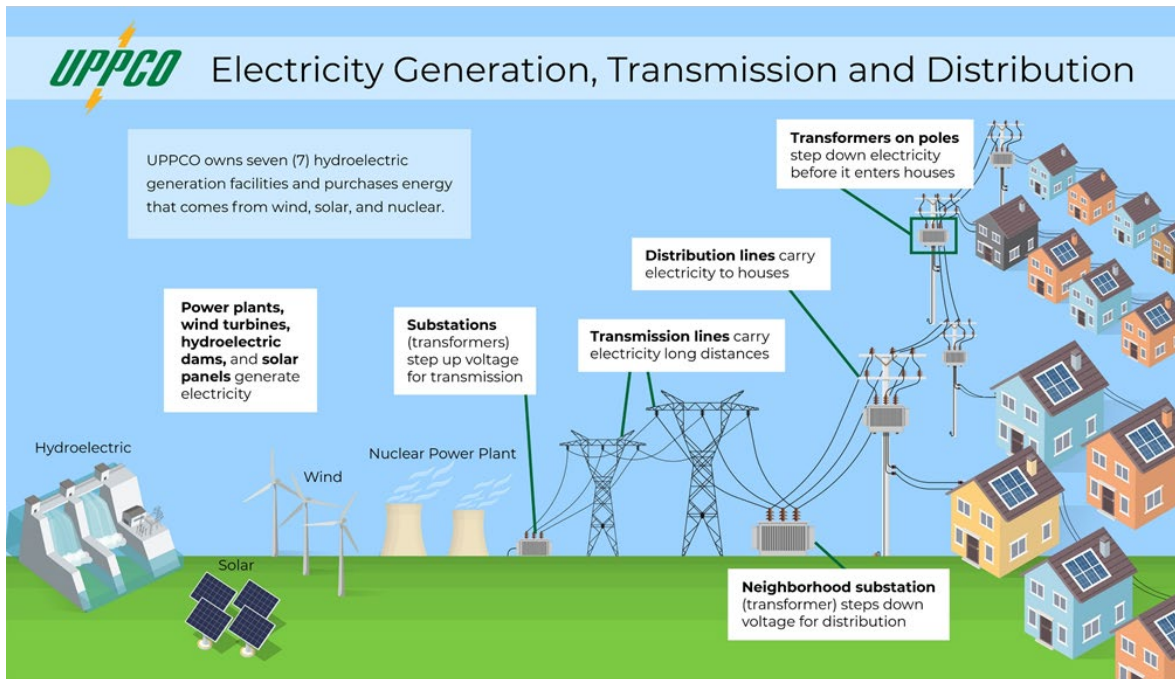
UPPCO has begun a Transformer Replacement Program to replace transformers manufactured prior to 1980. As stated in Section III, the average age of UPPCO's overhead transformers is about 36 years with nearly one-third of them manufactured prior to 1980 making them 44 years old or older. Per Appendix 9, *Distribution Plant Depreciation Table*, distribution transformers have an expected useful life of about 45 years, which indicates that many of UPPCO's transformers are either beyond or nearing the end of their service life.

UPPCO has been replacing transformers on an "as needed" basis, for service upgrades, reliability improvement projects, car-pole accidents, or failures. Proactive replacement of older units may prevent unplanned outages or overloading that may result in service voltage below standard and outside tariff limits.

The Transformer Replacement Program will strategically target replacement of the oldest transformers on the system first, along with replacement of all aging transformers while system improvement and customer jobs are being completed.

## **Substation Inspection, Maintenance, and Project Planning**

As stated earlier, UPPCO, like other electric utilities, energy providers, and communications companies, provides essential service and critical infrastructure to support the economy, health, and general welfare in the United States. If the distribution system is considered critical infrastructure, then substations comprise the most critical component of all distribution infrastructure.



A distribution substation is an interconnection to the bulk power system, i.e. “grid,” and transforms transmission voltages to distribution level voltages. As seen in the diagram above, every distribution feeder, or circuit, originates at a substation. Typically, two or more feeders originate at each substation. UPPCO has distribution substations with only one feeder and others with four or more. Generally, there are more feeders at substations located in more urban areas and less feeders at more rural substations.

Because each distribution feeder emanates from a substation, all customers on a feeder can be affected by the reliability of the substation. Whereas smaller numbers of customers are affected by faults further out on the distribution circuit. However, customers located near the ends of a circuit experience outages of all upstream devices. To minimize outages to all customers, reliability at substations is emphasized. Therefore, substation equipment maintenance and upgrades are crucial to distribution system integrity, reliability, customer service, and customer satisfaction and are a crucial part of UPPCO’s distribution planning and maintenance. These substation equipment maintenance and upgrade projects are constantly ongoing to ensure the reliability of UPPCO’s substations.



### Periodic Inspection Program

UPPCO works to maintain substation reliability through periodic inspections. Substation inspections are either conducted bi-monthly or monthly by UPPCO substation crews. UPPCO’s Substation Department has developed a substation inspection schedule that indicates the stations that will be inspected each month. All equipment in the station is reviewed during a substation inspection. Inspection forms are completed to document equipment counters, heater status, device temperatures, device pressures, and regulator steps. Any deficiencies are noted. Inspections are tracked in UPPCO’s SAP work order system. Any equipment problems noted by the substation technician are entered into the SAP Maintenance Work Order System to create an order to repair the equipment. An example of a completed substation inspection report is included in Appendix 8a, *Substation Inspection Report Example*.

In addition to the monthly inspections, the stations are winterized in the fall. This process involves checking to assure the heaters are working properly in breakers, circuit switchers, recloser control cabinets, and CT/PT junction boxes. The air conditioning units are turned off to check to assure the heating system is working in the control house.

### Maintenance Processes

Substation maintenance that is conducted based on the findings of substation inspections and on a regular schedule also ensure the reliability of UPPCO’s substations. Substation equipment maintenance is also tracked by UPPCO’s SAP Work Order System and in the preventative maintenance plans. Work orders are generated and printed bi-annually for equipment that needs to be maintained for that year. Once printed a supervisor schedules the work for the crews to perform. The timelines for substation equipment maintenance are shown below:

Equipment	Years
Circuit Switchers	10
Power Transformers	1
Microprocessor Relays	8
Vacuum Circuit Breakers	6
Gas Circuit Breakers	6
Oil Circuit Reclosers	6
Oil Circuit Recloser Outdoor Relays	6
Electromechanical Relays	4
Generation Microprocessor & Solid-State Relays	4
Generation Electromechanical Relays	2
Battery Testing	1
Power Transformer in Service DGA	1

An example of a preventive maintenance order for power transformer electrical test is included in Appendix 8b, *Substation Preventive Maintenance Order Example*.

Equipment testing and maintenance is important to ensure the equipment functions within its design parameters and settings for proper operation. If issues are discovered, it allows them to be corrected on a preventative basis and not in an unplanned or failure mode.



## Substation Standards

UPPCO also has a Substation Standards Committee that is comprised of employees from both the East and West Substation Operations groups and Substation Engineering. The Committee's work ensures the continued maintenance of UPPCO's substations. The frequency of the meetings was quarterly to review and update the Substation Standards. The meetings have been changed to bi-annual because all of the standards have been reviewed and are now up to date.

The Substation Standards do not dictate the equipment that the Substation Department purchases. But rather, the standards follow best utility practice for the installation of substation equipment.

## Asset Renewal Determination

Asset renewal decisions play a large role in UPPCO's substation maintenance program.

### Substation Power Transformers

Substation power transformers are very expensive assets with long lead times in the range of 1½ -2 years. Generally speaking, these units take power at transmission voltage, typically 69 or 138 kV, and provides distribution primary voltage at 12.47 kV, which powers each distribution feeder.

These transformers are absolutely essential to serve UPPCO customers. Therefore, UPPCO has created a "loss of bay" analysis to assure enough capacity exists elsewhere on the system in the event of a failure of any unit.

UPPCO's "loss of bay" philosophy has established multiple scenarios with different criteria applied to substations in order to address "loss of bay" scenarios. These range from fully redundant transformer configurations, to maintaining onsite a spare transformer, to maintaining a spare transformer at the service center, or to use a mobile or portable transformer.

Urban area scenarios for "loss of bay" include building adequate capacity and switching locations in the system in order to switch all of the load from a failed transformer to other transformers in the same substation or to another substation in the vicinity. Rural "loss of bay" response includes providing a second transformer bank in the substation serving another feeder, which is capable of serving the load of all feeder load with minimal switching. This second transformer in the substation may be energized or de-energized depending on multiple factors considered by UPPCO Operations.

There are several considerations that must be accounted for when determining how to provide "loss of bay" support for the feeders that currently do not have adequate "loss of bay" back up capacity:

- Cost of the solution, including consideration of future maintenance costs
- Cost if a transformer fails, including any potential Michigan reliability standards credits
- Probability of a transformer failure, considering asset management and preventative maintenance testing results, and:
  - Age
  - Current condition
  - Test results



- Gasses in oil
- Historical loading
- Through-faults experienced by the transformer
- Level of risk UPPCO management is willing to accept
- Customer impact:
  - Customer minutes of interruption (CMI)
  - SAIDI impact
  - Whether it supplies other electric providers, such as Ontonagon REA
  - Customer tolerance for a long duration outage
- Available space at the substation
- Environmental issues
- Financial impacts
- Age of assets
- Depreciated life (as determined by MPSC)
- O&M spend versus capital spend
- Other geographic considerations, such as:
  - Location of the mobile and spare transformers (actual distances to sites)
  - Travel time from storage location to site
  - Weather, road restrictions, etc.

UPPCO monitors the health of UPPCO’s power transformer fleet by performing yearly dissolved gas analysis (“DGA”) and electrical testing every 10 years. The typical life expectancy of a transformer is 40-50 years. If the Company were to have a failure of a transformer at a site where it does not have two bays available to serve customer load, the outage time would be extended because UPPCO would have to install a portable transformer.

### High Side Protection

As discussed above, substation transformers are an essential asset. Installation of a high-side circuit breaker with a protective relay package offers more protection to the transformer, UPPCO personnel, and the public. UPPCO’s current transformer protection package utilizes a high-side circuit breaker and zone of protection relaying that encompasses, not only the transformer, but the entire bay to the voltage regulators at the feeder exit. This is an expanded zone that offers more protection to employees while performing work inside the substation. For a failure mode within the transformer itself, the protective relay’s differential elements would operate and clear the fault much faster than a high-side fuse, which would limit the damage to the transformer and impact to the environment.



### Remote Terminal Units

UPPCO is in the process of updating remote terminal units (“RTUs”) in substations currently equipped with Opto-22 hardware that utilize a Windows XP computer to interface with the Opto-22 modules, which have become obsolete.

UPPCO has standardized on a Cooper platform, which is more user-friendly and has the computer integrated into the RTU with plug and play I/O modules.

### Human-Machine Interface

At larger substations, UPPCO currently utilizes a local Human-Machine Interface (“HMI”) screen in the control house, which provides technicians historical alarm data and the current state of equipment and circuit-loading.

In recent years, UPPCO has moved away from the HMI screens controlling field devices and has gone back to physical breaker control with a local/supervisory switch interface. UPPCO is implementing this breaker control philosophy for all substations regardless of size and whether or not HMI is currently used at that site.

### Recloser Controls

The protective relays that control reclosers are typically located at the reclosure itself in the substation yard and require a 24V battery for operation.

UPPCO’s most recent design includes a protective relay scheme utilizing an SEL-351 installed inside a relay panel within the control house rather than at the reclosure in the yard. This utilizes the existing 125V control house battery bank and a power supply to maintain the 24V interface required to operate the reclosure. This reduces required maintenance and replacement of the 24V batteries, which are necessary every six years. About 72% of UPPCO’s distribution substations utilize a control house, which serve more than 95% of UPPCO’s customers.

When a control house exists, the reclosure relays are now housed in a climate-controlled environment within the control house and are not subjected to moisture ingress and hot/cold cycling, unlike outdoor relaying. All the communication equipment is in the control house as well, so the communication paths are much shorter and more reliable.

### Reclosers/Breakers

UPPCO has experienced some operational issues with G&W Viper Vacuum Circuit Reclosers (“VCRs”), such as vacuum bottle failures during maintenance testing and some moisture intrusion into the VCR cabinets. Therefore, UPPCO has been replacing them with Cooper Oil Circuit Reclosers during other substation projects or upgrades.



## Control House

The substation control house is a very important asset because it houses all the substation communication equipment, protective relays, batteries, RTU, metering, and associated equipment.

Control buildings are scheduled for replacement when they are deemed outdated, they become subject to rodent issues, or there is not enough room for new or updated equipment.

As mentioned previously, about 72% of UPPCO's distribution substations are currently equipped with a control house serving more than 95% of UPPCO's customers. The substations without a control house generally either serve only one large industrial customer or a small number of very rural residential customers.

Control house improvements or replacements are planned with new construction or equipment upgrade projects at the substation. Currently, the Chatham control house is planned for replacement with other substation upgrades at the site.

## Substation Feeder Regulators

Voltage regulators at substations are another essential component of the distribution system as they maintain voltage within required limits and in the range necessary for customer electrical equipment. UPPCO primarily uses 219A and 328A voltage regulators on the substation feeder exits based on typical current and expected future loads.

Unlike transformers, voltage regulators have a number of moving parts that can become worn from regulator operation over time. Substation regulators are typically replaced based on the number of operations experienced and manufacturer recommendations.

UPPCO maintains spare regulators on hand in the event of a unit failure or other operational issues with indicators or controls. When UPPCO performs a construction project or equipment upgrade at a substation, the regulators are typically replaced at the same time.

The lead time to purchase a regulator is about 1½ years. Therefore, several spare units are kept on hand both for unplanned replacements or for new or upgraded feeders to serve customers.



## **Risk Mitigation**

UPPCO provides and maintains critical infrastructure that residents, municipalities, and businesses depend upon within its service territory in Michigan's Upper Peninsula. UPPCO's risk mitigation plans and processes are meant to ensure the safety of UPPCO's employees and the public, prepare for severe weather impacts, and guard against cyber-security attacks that could disrupt electric service.

### **Employee & Public Safety**

UPPCO works to make sure its distribution system is maintained in a way that ensures the safety of UPPCO employees and the public. Safety is a core value at UPPCO and indicative of how UPPCO does business. All decisions made at UPPCO have safety as a consideration. UPPCO is committed to line electrician safety through the team-driven approach of its Standards and Work Methods Committees. These Committees meet regularly to ensure we are on par with or exceeding NESC compliance measures and industry best safety practices. UPPCO team members network with regional and national counterparts to understand areas of further development. In addition to daily work group meetings and required annual refreshers, UPPCO annually provides line electricians with Advance Line Training which is targeted training conducted by industry subject matter experts.

UPPCO also trains employees beyond the required regulatory standard which gives employees the skills to navigate safety at a greater level. Risk management is a cornerstone to safety and UPPCO believes in training employees with the skillset to best identify risk prior to engaging in tasks. New employees start on day-one with a safety orientation and continue the practice with ongoing training relevant to each employee's needs.

UPPCO has a system of written programs and processes including a corporate safety rule book, corporate safety policies, and work practices (SOP's) specific to each work group. UPPCO's culture is collaborative with a continuous improvement mindset. Several cross-functional teams work to advance a culture of safety, namely a Safety Committee and Line Work Methods team.

Annual audits of all service center facilities are performed with UPPCO's insurance partners. Monthly safety meetings are required for all operational workgroups and metrics are embedded, daily, in pre-job briefings, pre-ride inspections, employee observations, proactive safety identifications, and near-miss reporting.

Injury cases are managed to ensure care to the employee and best practices for workers compensation. UPPCO manages contractors in the same respect, requiring safety prequalification criteria, safety meetings, and evaluation. UPPCO also invests in other proactive safety initiatives to prevent injury and increase well-being, such as daily stretching and ergonomic evaluations & assessments.

UPPCO's historical safety metrics are shown in the tables below:



OSHA Recordable Cases / Rates					
Year	2019	2020	2021	2022	2023
Cases	4	2	3	4	5
Hours	333,153	326,180	316,076	322,663	325,426
Rate	2.40	1.23	1.90	2.48	3.07

UPPCO’s OSHA Recordable Rate is based on the OSHA definition of a work-related injury or illness. The annual rates are required to be posted on an OSHA 300 log in each of the Company’s work centers as directed by OSHA rules. The OSHA Recordable Rate is the number of cases multiplied by 200,000 divided by the number of hours worked by employees. The 200,000 factor in the formula represents the number of hours 100 employees, working 40 hours per week, 50 weeks per year would work, and provides the standard base for calculating incidence rate for an entire year. The number of hours represents all of UPPCO’s employees’ actual hours worked, not including vacations, holiday, etc.

Lost Work Day Cases / Rates					
Year	2019	2020	2021	2022	2023
Cases	0	0	2	0	1
Hours	333,153	326,180	316,076	322,663	325,426
Rate	0.00	0.00	1.27	0.00	0.61
Days	0	0	11	0	22
Severity	0	0	5.5	0	22

An OSHA recordable does not always result in employee lost workdays. The table above indicates the number of actual workdays missed due to an injury or illness case along with the lost day rate based on the same number of hours reported for OSHA recordable cases. It also indicates the severity of those lost work cases on a per case basis.

UPPCO’s employees also hold a very good driving record. The table below indicates the number of miles driven against the number of vehicle incidents occurring “on the road” where the company employee is at fault:

Safe Miles Driven					
Year	2019	2020	2021	2022	2023
Hours	1,317,301	1,292,949	1,171,523	1,313,687	1,156,621
Incidents	0	0	0	0	0

UPPCO promotes public safety through special programs and public service announcements:

- UPPCO follows a written set of distribution standards that meet or exceed National Electric Safety Code (“NESC”) requirements, which are intended to provide for the safety of line workers and the general public.
- UPPCO is a member of MISS DIG and routinely publishes public safety announcements stating Michigan’s law to call MISS DIG at least three days prior to digging, which allows utilities to mark their underground facilities within the proposed project area. The system allows for anyone to create a “design ticket” used for project planning purposes. Facilities are not actually marked in



the field, but electronic facilities maps are provided to the requester so they can determine if underground facilities may be present in their project area before they get too far into their project design.

- UPPCO provides outage information at [uppcoco.com](http://uppcoco.com) and issues special notices during major storm events to keep the public apprised of unusual conditions. Phone numbers are provided on the website to report outages, downed power lines, or other related emergencies.
- Various other public safety announcements are published seasonally to communicate importance of being safe around hydroelectric facilities, downed power lines, trees/branches on a line, and how to identify a scam. UPPCO's website also lists current water levels at all hydro facilities which is updated every 10 minutes.

### **Storm Plan and Storm Management**

Storm response planning and management are another key piece of UPPCO's risk mitigation strategies. UPPCO uses a standardized manual and its OMS to prepare to respond to storm impacts.

UPPCO has employed the use of a Storm Restoration Manual, known as the "Storm Manual," for many years. The manual provides for storm preparedness in advance of storms, delineates Company organization and employee functions during a storm, and provides checklists for storm managers. This manual is reviewed and updated as needed by Distribution Operations and field personnel are routinely provided refresher training regarding various aspects of the Storm Manual.

One section of the manual is comprised of the Mutual Assistance Booklet, which is a separately printed document in booklet format to provide to outside crews working on behalf of UPPCO to restore service to UPPCO's customers. This booklet provides information about UPPCO-specific standards, storm operating procedures, safety, hold carding, communications, etc. UPPCO assigns a Field Coordinator, also known as "Bird Dog," to accompany outside crews and serve as a liaison between UPPCO storm managers and the crew.

UPPCO's OMS is the core of the outage management processes. The software is called InService and is provided by Hexagon. The OMS receives outage notifications from AMI meters or from customer calls and predicts the overcurrent protection ("OCP") device that triggered creating the outage, then UPPCO's system operators dispatch crews to the predicted outage location.

UPPCO provides an outage map available for public viewing at <https://www.uppcoco.com/outage-center/>. This map is linked to UPPCO's live OMS, so UPPCO's customers and the general public can stay up to date with the number of UPPCO customers experiencing power outages in real time. The online interface automatically refreshes every five minutes.

### **Inspections**

As discussed in the Storm Hardening section, *Overhead and Underground Inspections*, UPPCO performs routine inspections on predetermined cycles. These routine inspections ensure the entire distribution system is audited for safety, compliance, and strength and to ensure it will continue to meet standards for such until the next periodic cycle.



## **Grid Modernization (New Technologies / IT & OT Systems / Data Acquisition & Analysis)**

UPPCO will continue to upgrade and modernize the distribution system to meet the growing demand for clean, reliable electric service. In pursuit of that effort, UPPCO considers new technologies as well as enhancements and upgrades to its current IT applications to most effectively meet the current and future demand on the system. These efforts also help UPPCO to meet and exceed current and evolving MPSC service quality and reliability standards.

As mentioned in the grid hardening section above, UPPCO optimizes the use of existing technologies to improve reliability and strengthen the distribution system. Some of the specific methods are discussed in more detail below.

### **Geographic Information System**

UPPCO's Geographic Information System ("GIS") is the foundation for UPPCO's asset management processes. The GIS houses the vast majority of UPPCO's distribution plant records and provides the geographic location of distribution assets, equipment, and customers overlaid onto land and road network maps. Additionally, the GIS indicates the name and route of UPPCO's distribution feeders as well as the location of their origin at the substation. Substation plant asset data is maintained in another system. The feeder routing is extremely important for efficient patrolling of lines during outage restoration processes.

Customer data is also maintained in GIS by a migration process from UPPCO's Customer Information System ("CIS") in SAP (some of the same data is also sent to OMS). Much of this data is for internal use-only, and includes the customers' name, service address, mailing address, and premises and contract account information. This provides the necessary information for routine work and outage dispatch and reporting.

In addition to location, distribution plant asset records maintained in GIS include:

- Poles
- Overhead conductor – primary, secondary, and services
- Underground conductor and conduit – primary, secondary, and services
- Overhead and Padmount Transformers
- Regulators
- Reclosures
- Capacitors
- Lighting – yard and governmental
- Meters

Typical data associated with distribution assets include:

- Date set/installed
- Pole class and length
- Size in kVA or Amps
- Manufacturer date
- Communications attachments



GIS also provides the locations of equipment, such as:

- Substations
- Junction Enclosures
- Secondary Pedestals
- Fusing

Connectivity is of utmost importance in GIS as the database is migrated to OMS and also used for Cyme load flow modelling. Accurate circuit connectivity in GIS, as well as normal open points, along with overcurrent protection (“OCP”) device location data is not only of great value for OMS outage location prediction, efficient crew dispatch, to assist in line patrol and service restoration efforts, and to minimize outage length, but is an absolute necessity for accurate outage reporting. The GIS connectivity, which migrates to connectivity in OMS, allows for accurate customer counts in the OMS database and therefore reflected in outage/reliability reports.

Additionally, since UPPCO’s distribution line are designed and operated in a radial configuration, UPPCO’s GIS staff runs a loop analysis in GIS to identify and correct any electrical circuit loops, which would confuse the outage prediction logic built into OMS.

GIS data is integrated into many other systems and processes at UPPCO. It provides to and receives data from other IT systems as can be observed in Appendix 5, *GIS Flow Diagram*.

To further modernize the GIS system, UPPCO will be migrating its systems to ESRI ArcPro and the Utility Network in 2025. This will provide advantages of new ESRI technology, which should increase UPPCO efficiencies for both field and office personnel and allow for better management of the distribution system.

### **Outage Management System**

UPPCO’s OMS system and planned improvements to the system are crucial to UPPCO’s plans to improve distribution system reliability. A robust OMS provides the ability to dispatch outages more quickly to the correct outage location. Additionally, UPPCO implemented Automated Meter Infrastructure (“AMI”), which automatically reports customer outages and sends them to UPPCO’s OMS, indicating exactly which customers are experiencing an outage. This improves efficiencies with dispatching resources and aids in diagnosing system issues. UPPCO continues to work with the OMS and AMI vendors to improve UPPCO’s ability to ping meters following crew restorations and better identify customers who may still be experiencing an outage during storm conditions.

OMS imports the circuit model from UPPCO’s GIS. Additionally, UPPCO’s Customer Information System in SAP runs a routine nightly to export current customer data directly into OMS to provide up-to-date customer information within OMS.

UPPCO is currently working towards “phasing” within OMS. UPPCO’s GIS already identifies the phase of each section of line, but requires field verification, especially where the three-phase system is routed underground. At this time, approximately 80% of UPPCO feeders in GIS have accurate “phasing” data. The phasing project will improve OMS accuracy in that when a single fuse operates in a three-phase fuse setting, OMS will indicate only those customers served by that one fuse who are without service. Without proper phasing, OMS will predict an outage affecting all customers served by the three-phase fuse setting when, in reality, only the customers on the one open fuse would be without service.



As mentioned in the GIS section above, connectivity is of utmost importance in OMS. So, maintaining accurate GIS data will inherently maintain accuracy in UPPCO's OMS whenever data is migrated from GIS to OMS. Furthermore, when switching is performed in the field, system operators will open and close devices or create open points in the live OMS distribution system model, which keeps OMS consistent with actual field conditions. Therefore, outages are accurately detected and recorded in OMS for the actual real-time conditions.

UPPCO continues to work with its OMS vendor to enhance reporting capabilities, improve workflows, software feature utilization, and integration with AMI notifications. As outage reporting and outage management duties converge, UPPCO's business requirements of these systems are adapting and changing to match.

### **Automated Meter Infrastructure**

UPPCO's Automated Meter Infrastructure ("AMI") and planned enhancements to it are key to improved system maintenance, outage response, and reliability. UPPCO began implementing AMI for meter reading and billing purposes in 2019 following implementation workshops in 2018. The AMI system works on an RF mesh field area network ("FAN") consisting of AMI meters and mesh node base ("MNB") units that relay data from one another to a collector, called a connected grid router ("CGR"). The CGRs then transmit AMI meter data to UPPCO's head end where data is stored in an ITRON hosted solution. The meters collect daily reads for kWh billing and outage events among other data. UPPCO started working to optimize the FAN in 2021 and continues today.

At this time, over 99% of installed UPPCO meters are AMI meters. Due to its rural service territory, opt outs, and special metering to large customers, a small number of UPPCO's customers are not currently served by AMI meters.

As mentioned above, UPPCO has worked with its AMI and OMS vendors to report AMI meter-detected outages into OMS, which provides near real time outage reporting. UPPCO plans to continue to look for ways to utilize the AMI system for further outage, engineering, and analytics purposes.

UPPCO is continually analyzing its mesh network to identify areas and calculate the cost to add additional hardware to improve the communication from the meter to the head end. The areas UPPCO serves are sparsely populated and will require significant hardware and capital investment to improve communications. UPPCO has installed cellular point-to-point meters in some areas with poor communications with limited success. UPPCO is also investigating out of the box solutions that may be more cost effective, such as partnering with a cellular provider to expand coverage in those areas.

One goal is to leverage the AMI system to produce certain reliability metrics that cannot currently be reported by UPPCO's OMS, specifically the IEEE Momentary Average Interruption Frequency Index ("MAIFI") and Customers Experiencing Multiple Interruptions ("CEMI"). Another goal is to utilize AMI usage data for distribution system load modeling to identify operational limitations and to support distributed generation ("DG") hosting capacity analysis. Further, AMI power quality data may be used in the future to monitor real-time system conditions to aid network operations.

UPPCO expects to achieve such goals through enhanced access to AMI data in conjunction with further development and integration of its AMI and OMS systems. UPPCO is currently working on a project with



Itron to upgrade UPPCO's Itron Enterprise Edition MDM, which is expected to provide enhanced access to ITRON hosted AMI data including outage and restoration notifications from the meters. UPPCO has also secured Itron's assistance in the near term to improve integration of the "Itron Analytics" software and OMS integration.

### **Supervisory Control and Data Acquisition**

Supervisory control and data acquisition ("SCADA") monitoring and control of distribution feeders at the substation level are important components of UPPCO's effort to modernize its technology and improve reliability. SCADA provides several advantages for the outage restoration process. SCADA allows for rapid detection and isolation of faults occurring on the distribution system downstream of the feeder device. UPPCO feeder devices are equipped with reclosing logic which restores service quickly after a temporary fault such as an animal or tree contact resulting in only a short momentary outage to the customers served downstream of the reclosing device.

SCADA data is also used for historical and real-time loading analysis and troubleshooting. It is configured with alarms and trending functionality that allows for proactive decision-making and assists with planning prior to facilities being taken out of service.

UPPCO has a comprehensive SCADA system to remotely control circuit breakers and reclosers on the distribution system by its System Operating Department. UPPCO currently has 76 of its 84 distribution feeders equipped with SCADA control. These 76 feeders serve more than 99.5% of UPPCO's customers. Only the most remote and lightly loaded feeders are not yet equipped with SCADA monitoring and control. The SCADA system allows UPPCO system operators to remotely open and close substation feeder devices under normal operating or emergency conditions.

UPPCO's System Operating has procedures in place to handle emergency Bulk Electric System (BES) curtailments. UPPCO may be required to shed firm load when Midcontinent Independent System Operators ("MISO") declares a grid emergency. This load shed process is intended to help grid stability and maintain a bulk of customers in service during an extreme grid condition.

Under the direction of MISO and following National Energy Regulatory Commission ("NERC") standard PRC-006-5, several of UPPCO's feeders are equipped with underfrequency load shed ("UFLS") relaying which will automatically deenergize those circuits when the system drops to a predefined frequency level. The circuits with UFLS relaying are considered the last resort before the grid becomes unstable and collapses resulting in a black out to all customers.

Therefore, a priority listing (manual load shedding list) of feeders was developed for each operating district so system operators have a predefined order to drop firm load to prevent grid collapse. The amount of load required would be specified by MISO and the priority list was grouped so that blocks of load could be quickly identified for the required load reduction.

The manual load shedding list was developed so that the load shed is spread out within each district and substations with multiple feeders are not all included in the same block, or wave, of the load shedding process.

The priority list was broken into 5 groups:

- First Wave



- Second Wave
- Third Wave
- Last Resort
- Generation

The First and Second Waves are similar types of loads with multiple circuits at the same substation placed in different waves. The Third Wave includes circuits providing critical services, such as airports, bridges, and water & sewage treatment plants, as well as health care and elderly care facilities. The fourth group, or the circuits of “Last Resort,” are equipped with the UFLS relays. The fifth group (Generation) are those circuits with Generation facilities that help grid stability and should not be de-energized.

To enhance cyber security on the SCADA network, UPPCO is currently evaluating options for both hardware and software additions to provide alerts for any unusual activity and allow personnel to respond accordingly to any threats.

### **Overcurrent Protection Planning**

UPPCO’s overcurrent protection planning is another key component of its efforts to maintain and improve system reliability through grid modernization. UPPCO uses Cyme to perform overcurrent protection (“OCP”) analyses. Cyme is a program that imports UPPCO’s GIS circuit model. The available system short circuit current is loaded at each substation to perform the OCP analysis.

UPPCO has been reviewing the overcurrent protection plans on all feeders to assure that reclosers are properly set up, and that they coordinate with other line devices back to the substation. In some cases, overcurrent protection equipment is replaced with newer technology, which coordinates better with other devices on the system. Feeders that have a history of multiple device operations are prioritized first.

Following an outage, CYME is used to narrow down the location of outages with an unknown cause or to analyze cases of protective device miscoordination. In cases of new load on the system or when the system needs to be put into an abnormal configuration, CYME helps identify protection changes that must be made to accommodate the impact of the change in load.

### **Voltage Regulators**

The use of voltage regulators is also key to UPPCO’s ongoing and future efforts to improve system reliability. UPPCO currently has 102 locations with voltage regulators installed directly on the distribution lines (this number does not include voltage regulators installed at substations). Due to UPPCO’s sparse service territory and long distribution feeders, voltage regulation along the line is often necessary to maintain adequate service voltage to the end-use customers. Several stages of voltage regulators, including the substation feeder regulators, are not uncommon on UPPCO feeders.

Voltage regulators have been installed in specific locations that can operate in reverse load flow, so that they perform properly when switching the distribution system for partial restoration. This eliminates the requirement for field personnel to manually adjust regulators when switching occurs and frees those personnel to address other outages.



Further, UPPCO collects data from all voltage regulators annually, and on an as-needed basis, to monitor how the distribution system is performing and captures data for system modeling and planning. This data helps identify changes in load and overall system performance.

### **Distribution Automation**

UPPCO has also considered distribution automation (“DA”) projects. However, due to UPPCO’s mostly rural service territory, there are not a lot of areas where the use of DAs could be effectively implemented. When evaluating projects to improve reliability, however, UPPCO considers the potential use of DA.

UPPCO installed a partial DA project at a very remote substation fed by a radial transmission line. In this case, the line crew must travel a long distance to the substation to isolate and switch to a back-up feeder. UPPCO added SCADA-controlled switches to tie the feeders together to the back-up distribution source. Although it is not automatic, it reduces outage response from a couple hours to only a few minutes for transmission-related outage events.

### **Faulted Circuit Interrupters**

Faulted circuit interrupters (“FCIs”) are used extensively at UPPCO and predominantly on the underground distribution system. FCIs provide fault location information to assist field crews to determine the section of underground line where an underground fault may have occurred. The crew can then isolate that section and perform further testing to pinpoint and repair the location of the fault. Additionally, FCIs can also be temporarily deployed in cases of multiple unknown events or when the system is in an abnormal configuration to help narrow down a fault location.

FCIs may also be strategically placed on the overhead system to assist crews patrolling lines. Overhead FCIs are generally installed in locations where the line may traverse off the road ROW or where a line bifurcates without the use of an OCP sectionizing device. In other circumstances, an FCI may be placed in the middle of a longer line section between OCP devices thereby reducing the area that requires a crew to patrol to locate an overhead fault.

Due to the seasonal nature of line loading in many areas of the UPPCO system, UPPCO utilizes load tracking FCIs that automatically select a minimum trip threshold based on sampled load current. Some fault indicators also have multiple modes that display momentary and permanent events differently to assist with troubleshooting.

UPPCO is investigating the use of remote fault indicators and may begin installing them in the future. These devices would operate like a standard FCI but would provide immediate notification of faults to UPPCO staff and allow for real-time analysis by employees that are not in the field at the time of a fault, such as system operators or distribution engineers.

### **Potential Future Technological Innovations**

Technology is advancing quickly in the electric utility sector. The company is aware of the following new technologies but has not yet implemented them at UPPCO. These technologies are listed in this Plan for consideration, assessment, and potential future use by UPPCO.



### Line Sensors

Sensors installed at strategic locations throughout the distribution system can provide not only fault location, but also can capture power quality and load data that can be used to monitor real-time system conditions or later by distribution engineers for analysis of the overall health and capacity of the distribution system.

### Advanced Distribution Management System

Advanced Distribution Management System (“ADMS”) is a software platform that can help manage and optimize distribution systems. An ADMS may provide power quality data and could help to improve reliability performance by gathering data from several stand-alone systems, such as SCADA, OMS, AMI, line sensors, energy management, GIS, and CIS, into one viewing portal. An ADMS would also potentially help system operators react more quickly to system load and voltage functions due to faults or DER operation on the distribution system. A more efficient distribution management system may also help UPPCO more quickly identify outage locations and, subsequently, improve restoration, crew dispatch, and customer communications, and provide real-time data for load demand management.

### Distributed Energy Resource Management System

Distributed Energy Resource Management System (“DERMS”) is a software platform that can manage the flow of electricity from distributed energy resources (“DERs”). A DERMS would provide tools to help control system demand, monitor and manage renewable energy sources, such as wind and solar, and help system operators to maintain voltage stability on the distribution system. A DERMS would likely require integration with other systems, such as OMS and SCADA, as well as with individual DER owners or operators. A DERMS may be helpful to UPPCO as it plans to comply with the implementation of FERC Order No. 2222.

### Distribution Supervisory Control and Data Acquisition

Distribution Supervisory Control and Data Acquisition (“DSCADA”) is a system that allows communications to, and possibly control of, distribution line reclosers and other distribution equipment or sensors. During outage management processes, this system can provide real-time data to allow system operators to identify outage location and improve overall restoration efforts more quickly. DSCADA can also provide control of line reclosers or switches to isolate faulted section of the circuit and remotely switch section of lines to restore service to some customers before line crews are dispatched.

### Ground Level Distribution System

A ground level distribution system (“GLDS”) is similar to a standard underground distribution system, except that the cable lies in a cable tray just under the ground surface, which is then encased in concrete and covered with a protective cover. See sample image at right of a GLDS.

The installation of a GLDS could provide many benefits to the distribution system. These include a reduction of on-going line clearance and overhead maintenance costs, tree and weather-related outages, and fire risk. Additionally, the shallower trenches necessary for a GLDS may allow for the installation of GLDS lines where rocky conditions do not easily allow the installation of standard underground cable.

UPPCO Engineering was made aware of this new technology through an industry meeting, but still has many questions about using it in Michigan’s UP with frost, snow plowing, etc.

The GLDS still requires some road ROW space for the installation, which would necessitate county permitting. Driveways would also present an encumbrance to the installation. Entrance into standard pad-mounted equipment would also present new construction standards and potential operational issues. However, UPPCO remains interested in learning about the potential benefits of GLDS systems and how they can be integrated into UPPCO’s distribution system to improve system performance and reliability.



*Example of a Ground Level Distribution System  
\*Photo courtesy of Pacific Gas & Electric*

### **Non-Wires Alternatives / Solutions**

UPPCO also uses non-wire alternatives (NWAs) and is actively evaluating the potential of new NWA solutions that may improve the resilience and efficiency of UPPCO’s distribution system.

### Energy Efficiency / Energy Waste Reduction

Energy efficiency and energy waste reduction programs are a cornerstone of UPPCO’s NWA programs that seek to improve system reliability. UPPCO has offered energy efficiency programming to its customers since the 2008 “Clean, Renewable, and Efficiency Energy Act” was implemented by the Michigan Public Service Commission. Initially, UPPCO participated in the state administered program Efficiency United. Since bringing the energy efficiency program in-house starting on January 1, 2018, UPPCO continues to deliver energy savings and programs to its customers by using program implementors and by working with community-based organizations.

The UPPCO Energy Efficiency Portfolio is divided into low-income, residential, and commercial & industrial portfolio sectors. Each sector is further divided into programs. For the low-income sector, the programs include Income-qualified Single-family and Multi-family. For the residential sector, the programs include ENERGY STAR®, Home Performance, Appliance Recycling, Multi-family, and New



Construction. For the commercial & industrial sector, the programs include Prescriptive, Custom, and Small Business Direct Install. For the portfolio sector, the programs include Pilots, Education, and Customer Outreach.

*Low-Income Sector:*

UPPCO's Low-Income Programs target the Company's most vulnerable customers with incomes under 200 percent of the Federal Poverty Level ("FPL") and works toward offering a single point of contact. The sub-programs include:

(1) Single-Family – UPPCO's Single-Family Program is designed to specifically target low-income customers who own or live in a single-family home and have added barriers to measure affordability. The goal is to offer energy efficiency assessments and measures to qualifying customers, as well as energy literacy education and direct install energy efficient measures to qualifying customers at little to no cost to the end-user to overcome participation cost barriers.

(2) Multi-Family– UPPCO's multi-family program offers energy efficiency assessments, lighting and water conservation measures, refrigerator replacements, heat pump water heater installation, and cold climate heat pump installation.

*Residential Sector:*

UPPCO's Residential Programs allow for targeted marketing and implementation for encouraging customers to save energy when purchasing new appliances, recycling old appliances, and new construction. The Residential Programs include:

(1) ENERGY STAR® - UPPCO's ENERGY STAR® Program offers specific rebates on electric home appliances including air conditioners, ceil fans, dehumidifiers, dishwashers, dryers, and washers. The program aims to overcome participation barriers through in-store product price labeling and point-of-sale rebates.

(2) Home Performance – UPPCO's Home Performance Program implementation strategy offers individual rebates and Residential Energy Insight Assessments to provide customers with immediate energy saving measures and focus homeowners on the benefits of planning for multi-year home energy efficiency upgrades. The individual measures targeted include efficient delivery of lighting, water usage, heating, and cooling for homes.

(3) Appliance Recycling – UPPCO's Appliance Recycling Program ("ARP") offers event drop-off and home-pickup of refrigerators, freezers, room air conditioners and dehumidifiers to remove inefficient equipment from the distribution system while ensuring safe recycling of both the environmentally harmful refrigerants and the physical equipment.

(4) Multi-Family – UPPCO's Multi-Family Program offers Empower Energy Insight Assessments, lighting, and water conservation measures.

(5) New Construction – UPPCO's New Construction Program encourages customers to build new or renovate to all-electric homes utilizing high efficiency space heating and cooling, water heating,



lighting, cooking, clothes drying, as well as preparing for electrification of transportation and outdoor equipment.

*Commercial & Industrial Sector:*

UPPCO's Commercial Programs encourage small commercial to large industrial customers to operate more efficiently. The Commercial Programs include:

- (1) Prescriptive – UPPCO's Prescriptive Program offers rebates based on determined energy savings with the use of the Michigan Energy Measures Database and are pre-determined based on the measures installed.
- (2) Custom – UPPCO's Custom Program offers rebates tailored to the customer and specific project. The incentives are determined based on actual energy reductions at the completion of the project based on pre- and post-engineering evaluation and independent verification.
- (3) Small Business Direct Install – UPPCO's Small Business Direct Install ("SBDI") Program offers rebates to contractors for direct installation of specific measures for small business customers. The incentives are determined based on the determined energy savings at the completion of the project with the use of the Michigan Energy Measures Database and pre- and post-engineering evaluation and independent verification.

*Portfolio Sector:*

UPPCO's portfolio programs support all customers through education and research & testing. The portfolio programs include:

- (1) Pilots – UPPCO's Pilot Program is a method of testing new technologies or techniques to determine if the technology or technique proves to be beneficial to UPPCO's Energy Efficiency strategy and customers.
- (2) Education – UPPCO's Education Program relies on educational programming targeting 4th grade students and an interactive electric vehicle program targeting middle and high school students at schools throughout UPPCO's service territory.

The presentations meet State of Michigan curriculum standards and introduces students to the production of and efficient use of energy.

In addition, UPPCO, along with Consumers Energy, DTE, and Indiana Michigan Power founded the Michigan Heat Pump Collaborative ("MIHPC") and partnered with Slipstream for delivering the Collaborative's mission to:

*"Create a holistic education, outreach and training forum to pursue deeper engagement with manufacturers, distributors, trade allies, customers and other stakeholders to identify needs, remove barriers and ultimately increase adoption and participation in heat pump technologies."*



This Collaborative represents a long-term commitment for heat pump education and market transformation in Michigan.

UPPCO also works closely with program managers and implementation staff to provide customers with UPPCO Energy Efficiency branded services. This includes weekly conference calls to review customer related items, energy savings targets by program and program element, and overall portfolio delivery.

The weekly discussions enable UPPCO to make program and measure recommendations throughout the Energy Efficiency plan year to be more responsive to customer needs and changes in the marketplace. In addition, there are periodic meetings for collaboration and discussion of strategic planning, marketing campaigns and collateral, and initiatives.

### Energy Storage / Electric Vehicles Batteries

UPPCO continues to monitor and consider the use of battery storage (and electric vehicle batteries) as a way to improve distribution system reliability. Battery storage could come be from utility-scale batteries or independent developers or from the batteries of privately-owned electric vehicles (EVs).

UPPCO plans to comply with all requirements regarding the development of battery storage within its distribution system. Public Act 235 established a statewide energy storage target of 2,500 MW. By Dec. 31, 2029, investor-owned utilities (“IOUs”) will need to file petitions for approvals related to the storage target and Alternative Electric Suppliers (“AESs”) will need to file plans for how they will comply with the target. IOUs are required to file annual storage reports no later than Dec. 31, 2024.

On February 8, 2024, the Commission initiated Case No. U-21571 to undertake the work required to develop the storage targets. Utilities are required to begin filing annual reports documenting the centralized and distributed storage systems with their service territories.

As a result of PA 235, UPPCO will be required to install 12.9 MW of battery storage as their contribution to the 2,500 MW within the state.

At this time, no electric vehicle owners have approached UPPCO to sell EV stored battery energy back to UPPCO. However, UPPCO will continue to consider the potential role and uses of electric vehicle batteries as a way to improve system reliability.

### **Distributed Generation (“DG”) Interconnections**

UPPCO has developed systems to allow distributed generation to connect to its distribution system and sees DG resources as a potential avenue to improve reliability within the distribution system. Distributed generators comprise one type of Distributed Energy Resources (“DERs”) and the terms are sometimes used interchangeably at UPPCO. However, DERs include all possible sources of energy that may be interconnected to the distribution system. “DG” typically refers to wind, solar, or methane generation. DERs may also include battery or water storage, and demand response.



## Current Interconnection Process

The company allows customer standby and parallel generation interconnected with UPPCO's distribution system. The general interconnection procedures are provided in UPPCO's Electric Service Manual, Section 7, *Interconnects and Distributed Generation* (the manual can be found at <https://www.uppco.com/residential/electric-service-manual/>).

Information regarding UPPCO's generation program and interconnection procedures can be found at <https://www.uppco.com/business/customer-generated-electricity/#generation-program-overview>. Some of the details of UPPCO's generation and interconnection programs can be found below.

**■ Generation Program Overview**

**You can generate your own electricity and interconnect to the UPPCO grid to lower your power bill.**

If you are interested in installing your own electric generating system — such as a wind turbine, solar system or biofuel system — several steps are required to “interconnect” to the UPPCO electric distribution system.

**■ Generation Program Categories**

The customer-owned generation program is divided into categories 1 through 5 based upon the size or output of your generator. The eligible generator sizes, requirements, and processes of each category are detailed in this section.

For information related to outflow credit [click here](#).

**■ Generation Interconnection Queue**

View the Generator Interconnection Queue [here](#).

Five categories of DG are currently available as depicted below:

**CATEGORY 1**  
Generator Output 20kW or less  
[Learn more](#) ▼

**CATEGORY 2**  
Generator Output More than 20kW but Less than 150kW  
[Learn more](#) ▼

**CATEGORY 3**  
Methane Digesters–Generator Output More than 150kW but Less than 750kW  
[Learn more](#) ▼

**CATEGORY 4**  
Generator Output More than 750 kW but Less than 2 MW  
[Learn more](#) ▼

**CATEGORY 5**  
Generator Output More than 2 MW  
[Learn more](#) ▼



DG customers are required to take service under an existing tariff. The rules applicable to a DG installation are dependent upon the size of the project. These are laid out on UPPCO’s website (the information can be found here: <https://www.uppco.com/residential/services-rates/#uppco-rates-and-tariff>). The tariffs for each class of DG connector are located on the website at the pages indicated below.

<u>UPPCO’s DG Tariffs:</u>	<u>Page</u>
PG-1M Generation Net Metering Program (closed to new customers)	D-70.00
PG-2 Parallel Generation Modified Net Metering Program (Closed to new customers)	D-72.10
PG-3 Parallel Generation Methane Digesters (Closed to new customers)	D-72.40
PG-4 Parallel Generation Purchase by UPPCO	D-72.70
DG Rider	D-72.80

The Company currently has 321 participants in the Category 1 and 2 DG programs. Of these, 313 are in the Category 1 Tariff (20kW or less), with a total generation capacity of 2,076 kW. The remaining eight participants fall into the Category 2 Tariff (over 20 kW but less than 150 kW), with a total generation capacity of 312 kW.

DER Aggregation & Preparations for FERC Order No. 2222

DER aggregation within UPPCO’s service territory represents another potential resource that may affect the reliability of UPPCO’s system. Individual DERs may be too small to meet minimum size and performance requirements to participate in the regional wholesale energy market. FERC Order No. 2222 is a rule that allows DERs to aggregate and participate in the market. For UPPCO this means aggregated DERs may participate in the MISO market.

With the generally small amount of interconnected DERs at this time at UPPCO, it is expected FERC Order No. 2222 will not have an impact within UPPCO’s footprint for several years. During this time, UPPCO plans to learn from DER aggregation in other states and from the larger utilities in Michigan’s Lower Peninsula that have experience with DER aggregation.

Hosting Capacity Analysis/Maps

UPPCO’s plans to develop hosting capacity maps and analyses also will allow for better integration of DG resources into its system. As mentioned in IV.C, DER Forecasting, UPPCO currently performs a system analysis using Cyme for proposed DERs 50 kW or greater on a case-by-case basis.

UPPCO staff has created a simple hosting capacity map in UPPCO’s ArcGIS system based on conductor size data for use in the interim until a more detailed hosting capacity analysis (“HCA”) and map can be produced and provided for public viewing.

Snips of the interim map can be viewed in Appendix 7, *Interim Hosting Capacity Map*. The hosting capacity map is currently setup for internal viewing and use only.



The circuit view map only portrays UPPCO three-phase, primary, distribution system with different colors assigned to the various conductor sizes. The feeder numbers and streets appear as the map is zoomed in. This interim map may be used by potential DER developers to help determine adequate locations for DER installation in the distribution network.

To further support interconnection of distributed generation projects, UPPCO plans to develop a more granular hosting capacity analysis of the distribution system and produce high quality hosting capacity maps based on distribution system capabilities. Such HCA will require enhancements of UPPCO's existing software tools plus significant staff time and resources to implement.

Working with its system model partner, Eaton, UPPCO recently purchased the Cyme Integrated Capacity Analysis ("ICA") module to perform a complete hosting capacity analysis. In phase two of this project, UPPCO plans to purchase another add-on software tool that can "push" the results of the Cyme HCA to GIS, which will then give UPPCO's GIS group the ability to develop a hosting capacity map within the ESRI ArcGIS platform and finally a public-facing map.

### Load Management

UPPCO also makes use of load management to maintain reliability on the system. UPPCO has a number of customers on an interruptible rate that can be called upon under certain specific conditions. Interruptible customers' load may be curtailed due to emergency system constraints or based on day-ahead regional energy pricing, although customers have an option to buy-through when economic interruptions are requested.

UPPCO's Commercial Power – Interruptible Rider ("CP-I") can be found at:  
<https://www.uppco.com/residential/services-rates/#uppco-rates-and-tariff>

UPPCO's distribution system planning does not account for interruptible load since the system constraint must be a declared event given certain system conditions placing the grid in jeopardy. Since these conditions cannot be known in advance, UPPCO Distribution Engineering designs the distribution system for expected peak load plus future load growth.



## Financial Model/Projections (Summary Level Business Drivers)

### Capital Expenditures (“CapEx”)

UPPCO’s CapEx are geared toward improving system reliability through modernization of its distribution system. Appendix 6, Table 1, *Distribution and Substation Projected Capital Expenditures by Business Driver* indicates planned substation and distribution CapEx expenditures over the next five years. Key components of each business driver are discussed below.

#### (1) Line 03 Facility / Land

This budget line item is typically used to acquire land for new substations or for substation expansion projects.

#### (2) Line 04 Improve Reliability / Load Growth

This budget line includes projects necessary to maintain system capacity and voltage levels to serve customers as well as miscellaneous distribution projects under \$50,000 that develop over the course of the budget year. This line also includes System Hardening and Reliability Projects (“SHARP”) that meet UPPCO’s design criterion and prioritization to methodically improve distribution system performance, which are listed in Appendix 6, Table 2, *System Hardening and Reliability Projects*, for the upcoming year.

#### (3) Line 05 New Equipment / Equipment Upgrade

This budget line is for routine, reoccurring distribution capital expenses that are known to occur from year to year for new equipment and equipment in need of replacement or upgrade.

The budget is based on historical values and includes such items as, distribution line and substation transformers, substation breakers and associated relaying components and battery banks, reclosers, switches, regulators, meters, CTs (current transformers), PTs (potential transformers), capitalized tools and test equipment, and substation control buildings.

Substation equipment in Line 05 with an initial equipment and installation cost of \$100,000 or more are individually budgeted under this line item. Substation equipment is generally purchased for a specific project and includes the equipment installation costs. Additionally, substation equipment lead times can be significantly greater than distribution equipment so the planning horizon may be a year or two in advance of the planned construction budget year.

Due to the relatively low cost of individual distribution line equipment included in this line, they are generally grouped, ordered, and purchased as a lot rather than for a specific project. In addition, they are stocked for use throughout the year and are not slated for individual projects. For example, based on UPPCO’s experience, it is known that a quantity of line transformers will be installed in any given year to serve new customers, or replaced due to age, failure, or damage. However, it is unknown exactly the amount necessary, therefore, quantities are ordered and stocked in anticipation of expected usage plus a conservative overstock for unforeseen, higher than expected need in that year.

#### (4) Line 06 New Customer / Service



This budget line is for routine, reoccurring distribution capital expenses that are expected from year to year and are budgeted based on historical values. This line includes the installation of new electric services, lighting fixtures, and line extensions for customers requesting new or upgraded service, or for removal of service or lighting facilities where the service is no longer needed to serve an end-use customer. Similarly to distribution equipment, based on past experience, UPPCO is aware that new electric service installations, upgrades, and removals will occur during the budget year, but it is unknown the quantities of facilities that will be needed for these requests. Therefore, this budget line is a placeholder for these expected capital costs.

#### (5) Line 07 Contractual / Regulatory / Statutory

This budget line is for routine, reoccurring distribution capital expenses that are known to occur from year to year and are budgeted based on historical values. This line includes mandated, but unforeseen, projects to help account for CapEx associated with work, which is not elective under UPPCO planning, such as governmental road moves.

Also, this budget area includes expected costs for EVC installations under the Charge UP Michigan grant process. Therefore, this budget line holds the added UPPCO capital investment included as part of Michigan Department of Environment, Great Lakes, and Energy (“EGLE”) electric vehicle charging grant process under the Commission’s Case No. U-21137. As a result of the Case, UPPCO Rate C-1 was temporarily modified to encourage the development of electric vehicle fast chargers within UPPCO’s service territory. As part of the Order, a regulatory asset was created to track capital contributions by UPPCO in support of the grant process. Once fulfilled, this budget line item will no longer be needed.

#### (6) Line 08 Special Projects

This is a discreet, non-recurring, budget item to address the added costs associated with planned projects that do not fit under one of the other budgetary line items. At this time, UPPCO has no planned special projects, and therefore, no additional costs are shown in the Special Project line item over the 5-year budget period.

Appendix 6, Table 2, *System Hardening and Reliability Projects*, lists UPPCO’s planned distribution SHARP projects for the upcoming year. These projects are deemed necessary to improve reliability to specific areas of the distribution system.

SHARP projects undergo a rigorous selection and prioritization process, as explained in Prioritization Methodology section. Additional justification for SHARP projects is discussed in detail below.



## Operations and Maintenance (“O&M”) Costs

UPPCO includes the expected substation and distribution O&M costs in UPPCO’s overall O&M budget for typical maintenance activities. Appendix 2, Table 4 includes UPPCO’s expected substation and distribution O&M expenditures.

Historical line clearance, inspection, and total distribution maintenance costs are shown in Appendix 1, Tables 7, 8, 9, and 11. These tables indicate generally increasing costs of maintenance activities over the 5-year period from 2019 through 2023. Overhead maintenance costs can be incredibly variable based on the frequency and severity of storm activity over the course of the year and accounts for some of the variability in the annual costs over the five years reported. These costs are included in UPPCO’s overall O&M budget and account for inflationary factors.

## **SHARP Projects & Justifications**

UPPCO is planning to implement the projects that are shown in Appendix 6, Table 2, *System Hardening and Reliability Projects*. These projects are UPPCO’s large distribution CapEx projects with a total estimated project cost exceeding \$50,000. The identification of these projects ultimately informs UPPCO’s reliability improvement and the load growth component of the Company’s distribution CapEx plan.

Due to UPPCO’s low customer density and miles of line per customer, it is difficult to significantly improve reliability and resiliency of UPPCO’s system in a way that is easily observed by monitoring standard system-wide reliability metrics.

In UPPCO’s experience, to increase reliability and resiliency of the distribution system, there are two tried and true basic options: 1) Rebuild and harden the overhead system, or 2) Replace the existing overhead system with underground facilities. With either option, rerouting is always a consideration to improve accessibility and maintenance. If UPPCO chooses to rebuild overhead, then the design will include “hardening” the system through the use of Class-3 and taller poles that are built to UPPCO’s current construction standards, which improves spacing on the pole. The benefits of underground have been extensively discussed in previous sections of this Distribution Plan.

As discussed above in the Strategic Undergrounding section, O&M costs of UPPCO’s underground distribution facilities is far less than the O&M cost of overhead facilities on an overall, as well as on per mile basis. As such, the O&M costs for proposed underground projects is not a determining factor in the evaluation of discrete segments of line covered in each project. Rather, the strategic undergrounding projects put forth are based on the criteria already described and based on SHARP criteria and on the conditions present for the specific project under consideration, such as the soil type, vegetation, accessibility, number of customers, etc.

Also, as previously mentioned in the Strategic Undergrounding section, UPPCO plans to replace more existing, aged, overhead facilities with underground cable and associated components. However, each project is individually reviewed by Distribution Engineering with consideration of the merits of keeping lines overhead versus moving them underground, including initial construction cost as well as ongoing maintenance costs.



Overhead projects will be undertaken when circumstances make undergrounding impractical, or it is not deemed a long-term cost-effective solution. Improved overhead construction practices are already in place to help achieve an overall distribution system that is less susceptible to pole breakages and provides long-term maintenance savings in cases where underground is not a viable solution.



## List of Appendices

### Appendix 1 – Distribution Data

- Table 1 – Distribution System & Asset Information
- Table 2 – Historical Reliability Indices
- Table 3 – Historical Major Event Days
- Table 4a – Outages by Cause
- Table 4b – Distribution Equipment Outages
- Table 5a – 10-Year Historical Load
- Table 5b – 10-Year Load Forecast
- Table 6 – Worst Feeder Rank 2021-2023
- Table 7 – Line Clearance History
- Table 8 – Pole Inspection History
- Table 9 – Underground Inspection History
- Table 10 – Underground Outage History Compared to All Outages
- Table 11 – Historical Maintenance Costs

### Appendix 2 – Project Costing Calculation

### Appendix 3 – Line Clearance

- 3a – Line Clearance Project Areas Map
- 3b – Tentative Line Clearance Project Schedule

### Appendix 4 – Distributed Generation Process Checklist

### Appendix 5 – GIS Flow Diagram

### Appendix 6 – Budget Forecast

#### Table 1 – Distribution & Substation Projected Capital Expenditures by Business Driver

#### Table 2 – System Hardening and Reliability Projects

#### Table 3 – Substation CapEx Projects

#### Table 4 – Distribution & Substation Projected Operations & Maintenance Expenditures by FERC Account

### Appendix 7 – Interim Hosting Capacity Map

### Appendix 8 – Substation Records

#### 8a Substation Inspection Report Example

#### 8b Substation Preventative Maintenance Order Example

### Appendix 9 – Depreciation Table

**Distribution System & Asset Information**

Service Area (approx)	4,500 sq. mi.
Counties Served	10
Customers <sup>1</sup>	53,898
Meters <sup>1</sup>	58,956
Circuit Miles <sup>2</sup>	4,574 miles
Line Miles <sup>3</sup>	4,518 miles
OH Primary	2,170 miles
OH Secondary	596 miles
OH Service	520 miles
Total OH	3,286 miles
UG Primary	810 miles
UG Secondary	45 miles
UG Service	378 miles
Total UG	1,232 miles
Dist. Circuits <sup>4</sup>	85
Substations <sup>5</sup>	37
Pole Attachments	72,767
UPPCO-owned Poles	67,569
Foreign-owned Poles	5,198
Transformers	23,979
OH	19,343
UG	4,636
Recloser Settings (Line)	102
Regulator Settings (Line)	110

<sup>1</sup> The numbers of Customers and Meters is from SAP as 3/1/24 (trx ZCUSTDEV).

<sup>2</sup> Circuit miles counts double-circuited areas twice; data from GIS as of 1/10/24.

<sup>3</sup> Line miles from GIS as of 1/11/24.

<sup>4</sup> The number of distribution circuits does not include generation-only circuits, spare bays, bays strictly used for back-up or stand-by purposes, or those tapped off of UPPCO's 33kV system.

<sup>5</sup> The substation count is based on stations with a transmission interconnection. The count does not include stations powered by UPPCO's 33kV system.

Historical Reliability Indices

Year	All Weather						Excluding MEDs per IEEE 1366					
	SAIDI		SAIFI		CAIDI		SAIDI		SAIFI		CAIDI	
	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.
<b>2019</b>	782	421	2.39	1.79	328	214	211	162	1.78	1.31	119	123
<b>2020</b>	231	435	1.83	1.9	126	214	206	178	1.77	1.45	116	124
<b>2021</b>	249	394	1.38	1.76	181	206	149	175	1.16	1.41	128	125
<b>2022</b>	554	390	2.22	1.79	249	201	205	181	1.48	1.46	138	124
<b>2023</b>	412	446	1.37	1.84	243	225	141	182	0.98	1.43	127	126

Data excludes transmission-caused outages.

Benchmarking SAIDI Excluding MEDs

Year	UPPCO	Alger Delta	Clover-land	Con-sumers	DTE	I&M	NSP	UMERC	Utility Average	IEEE Q1/2	IEEE Q2/3	IEEE Q3/4	EIA-861 Ave
2019	211	538	325	233	202	332	100	235	272	86	126	178	148
2020	206	164	335	195	142	236	244	222	218	91	127	168	130
2021	149	160	286	228	136	312	177	218	208	97	136	190	138
2022	205	349	376	182	146	236	209	247	244	90	131	191	149
2023	141	101	214	176	157	210	164	187	169	84	119	186	128
5-Yr Avg	182	262	307	203	157	265	179	222	222	90	128	183	139

1) Data for individual Michigan utilities obtained from U-12270 annual reports.

Historical Major Event Days ("MEDs")

Year	TMED	#MEDs	SAIDI Goal*	Annual SAIDI*
2019	17.0	5	152	211
2020	17.4	1	146	206
2021	18.5	1	163	149
2022	17.3	4	160	205
2023	18.6	2	163	141

\* Excluding MEDs

Outages By Cause

All-Weather

Cause Description	SAIDI	%	Events	%	# Cust.	%
Vegetation	1,008	45%	2,964	30%	212,998	40%
Weather-Other	737	33%	1,394	14%	81,933	15%
Equipment	168	8%	1,927	19%	81,809	15%
Unknown	94	4%	857	9%	43,257	8%
Public	70	3%	306	3%	31,207	6%
Other	63	3%	92	1%	35,383	7%
Planned	34	2%	719	7%	12,988	2%
Wildlife	32	1%	1,466	15%	27,467	5%
Lightning	22	1%	261	3%	12,142	2%
5-Year Total	2,227	100%	9,986	100%	539,184	100%

Excluding MEDs

Cause Description	SAIDI	%	Events	%	# Cust.	%
Vegetation	405	44%	2,218	26%	150,138	36%
Equipment	159	17%	1,884	22%	79,887	19%
Weather-Other	113	12%	802	9%	35,164	8%
Unknown	84	9%	838	10%	41,278	10%
Public	70	8%	302	4%	31,022	7%
Wildlife	32	4%	1,465	17%	27,466	7%
Lightning	21	2%	258	3%	12,112	3%
Other	17	2%	65	1%	32,062	8%
Planned	11	1%	710	8%	12,345	3%
5-Year Total	912	100%	8,542	100%	421,474	100%

Data sorted by SAIDI.

Data excludes transmission-caused events.

**Distribution Equipment Outages**

<b>Cause Description</b>	<b>SAIDI</b>	<b># Customers</b>	<b>% of Customers</b>
Dist Equip Failure Cutout	63.3	36,150	44.2%
Dist Equip Failure Other	26.7	11,519	14.1%
Dist Equip Failure Insulator	25.4	8,294	10.1%
Substation Outage	9.2	7,700	9.4%
Dist Equip Failure Conductor	19.2	5,636	6.9%
Dist Equip Failure Arrester	8.8	4,567	5.6%
Fuse Coordination	8.4	3,903	4.8%
Dist Equip Failure Connector	3.2	2,949	3.6%
Dist Equip Failure Fuse	0.9	511	0.6%
Dist Equip Failure Transformer	2.2	451	0.6%
Fuse Nuisance	0.4	129	0.2%
<b>5-Year Total</b>	<b>167.7</b>	<b>81,809</b>	<b>100%</b>

Data sorted by SAIDI.

Data excludes transmission-caused events.

10-Year Historical Loads

Interconnection Point	2013 EDC Actual 8/27/13 @ HE16		2014 EDC Actual 7/22/14 @ HE17		2015 EDC Actual 8/14/15 @ HE16		2016 EDC Actual 7/22/16 @ HE17		2017 EDC Actual 6/12/17 @ HE15		2018 EDC Actual 6/29/18 @ HE17		2019 EDC Actual 7/19/19 @ HE17		2020 EDC Actual 7/7/20 @ HE15		2021 EDC Actual 7/6/21 @ HE15		2022 EDC Actual 6/21/22 @ HE17		2023 EDC Actual 8/23/23 @ HE17		
	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	
Alger Total (Prison)	1.49	0.30	1.30	0.26	1.31	0.26	0.00	0.00	1.14	N/A	1.31	0.65	1.27	0.61	1.17	0.54	0.95	0.49	1.15	0.48	1.02	0.45	
Atlantic	3.23	-0.20	2.86	-0.41	2.52	-0.98	2.34	-1.03	N/A	N/A	2.77	-0.26	1.46	-0.20	3.07	-0.37	2.56	0.39	3.48	0.66	2.81	0.31	
Barnum 1					0.34	-0.16	0.43	-0.11	0.31	N/A	0.03	-0.17	0.22	0.34	0.66	1.15	0.19	-0.49	2.65	1.21	3.80	0.78	
Barnum 2	5.70	0.32	4.91	-0.11	5.57	-0.70	5.52	-0.23	4.70	1.41	5.39	1.33	5.28	1.32	6.12	1.58	4.53	0.73	6.12	1.31	5.08	1.03	
Barnum 3	6.18	0.35	5.32	-0.12	5.64	1.05	5.50	0.87	4.85	N/A	5.79	0.86	5.83	1.56	6.11	1.56	3.96	0.52	5.93	1.32	5.21	1.12	
Bayview Total	1.70	0.43	2.10	0.68	1.48	0.48	2.51	0.79	1.75	N/A	1.80	-0.50	1.90	-0.70	2.40	-0.40	1.30	0.30	2.20	0.50	1.90	0.40	
Chatham Total	0.90	-1.80	0.79	0.28	0.84	0.29	0.91	0.31	0.69	N/A	0.89	0.30	0.72	0.20	1.02	0.30	0.77	0.18	1.00	0.27	0.84	0.25	
Delta 1	6.16	0.24	6.85	0.47	6.41	-0.34	4.10	0.50	3.09	0.22	3.21	0.08	3.90	0.28	4.05	0.32	2.52	-0.43	3.80	-0.07	3.02	-0.30	
Delta 2							3.84	-0.03	2.41	-0.53	3.37	-0.31	3.88	-0.07	4.04	-0.19	2.25	-0.84	4.26	-0.11	3.11	-0.39	
Elevation Bank 1	4.03	-0.37	3.00	-1.35	3.70	-0.93	1.57	-0.16	2.72	0.69	3.36	0.88	3.42	0.91	0.00	0.00	5.62	1.50	3.62	0.95	3.17	0.95	
Elevation Bank 2	5.50	0.51	4.07	-0.39	4.79	0.16	5.76	-0.80	3.08	0.47	3.66	0.73	3.22	0.54	7.32	2.11	0.00	0.00	3.25	0.39	3.17	0.69	
Forsyth																			2.07	1.80	1.54	0.42	
Freeman-34.5kV	-2.41	0.12	0.72	0.38	0.22	0.56	0.18	0.39	0.55	N/A	1.54	2.84	0.48	0.44	0.18	0.25	0.20	0.33	0.16	0.12	0.21	0.21	
Gwinn Total	3.73	1.10	3.72	1.08	4.04	1.16	4.02	1.04	3.04	N/A	4.20	1.06	4.45	1.19	3.81	0.79	2.76	0.31	2.38	0.41	2.00	0.20	
Henry St Total	7.77	-0.89	6.65	-0.47	7.99	0.44	9.43	0.91	N/A	N/A	6.91	1.37	2.93	1.63	7.42	2.36	5.58	1.35	7.57	1.10	6.82	2.11	
Homer Road	2.15	1.53	3.01	1.82	2.10	1.23	2.39	1.41	1.73	1.29	2.20	1.43	2.93	1.63	1.55	0.90	1.55	0.90	3.06	1.37	3.23	1.72	
Humbolt Mine Bank 1	0.00	0.00	0.18	0.09	3.92	1.82	3.14	1.43	0.17		1.30	0.47	1.09	0.37	1.06	0.35	1.04	0.25	1.07	0.35	1.27	0.54	
Humbolt Mine Bank 2									0.29		2.30	1.47	2.39	1.53	2.46	1.57	2.17	1.20	2.54	1.65	2.25	1.48	
Keweenaw	1.17	0.36	1.24	-0.03	1.51	0.03	1.54	0.48	0.79	N/A	1.15	0.24	1.34	0.34	1.38	0.29	1.19	0.19	1.28	0.27	1.09	0.21	
KI Sawyer Bank 1	6.36	2.64	5.22	1.88	4.27	1.10	3.12	0.50	0.98		1.32	0.40	1.42	0.36	1.65	0.41	1.65	0.41	1.82	0.41	1.54	0.35	
KI Sawyer Bank 2									2.25		2.25	1.16	1.53	0.12	2.17	0.49	2.17	0.49	2.46	-0.22	2.78	-0.17	
Lake Mine	0.15	0.07	0.12	0.06	0.12	0.06	0.13	N/A	0.10	N/A	0.13		0.16	-0.01	0.13		0.10		0.13		0.11		
Lakehead Rapid River	3.49	1.68	3.22	1.57	3.16	1.27			1.84	N/A	2.11		3.17		2.29		3.07		4.09		2.82		
L'Anse Bank 3 (UPPCO)	2.62	-0.05	2.24	0.07	2.35	-0.04	2.49	0.01	2.27	N/A	2.28	0.29	2.24	0.33	1.32	0.01	0.75	-0.33	1.27	-0.07	0.95	-0.17	
Lincoln Ave Bank 1	7.16	2.05	6.84	1.23	7.43	1.39	7.29	1.13	3.14	0.90	3.08	0.54	3.33	0.80	3.12	0.64	2.77	0.67	3.71	0.90	3.35	0.96	
Lincoln Ave Bank 2									3.23	0.48	3.64	0.64	4.21	0.71	4.03	0.59	3.06	0.02	4.24	0.68	3.19	0.07	
M-38 Total	1.36	-0.23	1.46	-0.29	1.66	0.15	1.22	0.04	1.27	N/A	1.17	-0.02	1.86	0.13	2.13	0.24	1.47	-0.06	1.31	-0.50	1.87	0.09	
Masonville Bank 2	1.49	0.30	1.52	0.33	1.55	0.30	1.89	0.59	1.38	N/A	1.50	0.36	1.98	0.58	2.01	0.69	1.80	0.41	2.01	0.69	0.28	0.17	
Masonville Bank 3																					1.00	0.18	
Mead (aka - Verso,Billerud )	35.33	-6.69	16.70	-1.01	-1.29	-0.30	34.68	3.55	30.25	N/A	23.00	-1.73	34.59	7.02	17.10	0.00	20.98	3.98	32.75	2.20	32.63	17.82	
MTU Bank 1	9.43	3.98	7.19	3.02	8.22	3.51	6.20	2.50	5.26		4.62	2.43	5.10	2.56	4.45	2.40	3.43	1.94	4.61	2.32	5.69	2.64	
MTU Bank 2									2.59		2.28	0.50	2.26	0.71	2.45	0.71	1.91	0.43	2.45	0.58	2.41	0.61	
Munising Bank 2	5.26	0.97	4.70	0.00	4.82	-0.01	6.51	1.06	3.89	0.31	3.90	0.00	4.08	0.36	4.34	0.36	3.14	-0.42	3.62	-0.28	3.49	-0.33	
Munising Bank 3 (Mill 2.4 kV Load)	0.43	0.07	0.29	2.93	0.71	2.30	0.40	0.29	0.40	1.81	0.12	2.47	0.86	2.47	1.02	0.94	0.93	0.83	5.59	3.48	3.98	2.56	
Munising Bank 4 (Mill 13.8 kV Load)	0.13	1.32	0.10	0.06	0.41	2.31	0.11	0.06	0.12	0.06	0.11	0.07	0.08	0.11	0.11	0.06	0.06	0.05	0.87	0.63	0.99	0.68	
Munising Bank 5									0.88		1.29	-0.16	1.27	0.40	1.25	0.36	0.84	-0.40	1.25	-0.22	1.11	-0.22	
Ontonagon Total	3.07	0.47	2.23	0.08	2.71	0.36	2.95	-0.04	1.99		1.69	-0.53	2.87	-0.23	2.86	0.28	2.14	0.54	2.88	0.81	2.88	0.81	
Osceola Bank 1	11.56	1.07	10.11	0.68	10.89	0.72	10.73	0.07	9.51	-0.08	5.77	0.90	5.90	1.11	6.26	1.09	9.21	0.52	6.34	1.44	6.07	1.23	
Osceola Bank 2									4.38	0.10	4.42	0.24	4.55	0.33	5.83	0.00	4.48	0.00	4.48	0.00	4.05	-0.09	
Perch Lake T1	1.06	0.18	1.05	0.13	1.07	-0.01	1.09	0.16	0.85		1.16	0.22	1.25	0.25	1.25	0.25	0.93	0.00	1.25	0.20	1.22	0.19	
Perch Lake T2																							
Rockland UPPCo	0.20	0.02	0.17	0.01	0.17	0.01					0.26	0.58											
Sawyer Lumber					1.01	0.33	3.08	N/A	3.08		3.08		0.84		3.06		3.06		1.45		3.02		
Seney - Bank 1	1.49	0.23	1.36	0.17	1.38	0.19	0.65	0.18	0.48	0.12	0.48	0.12	0.67	0.15	0.78	0.15	0.57	0.08			0.14	0.02	
Seney - Bank 2																					0.52	0.08	
Shingleton													1.20	0.56					1.00	0.50			
Timber Products	0.41	0.10	0.36	0.08	0.61	0.38	0.31		0.43	N/A	0.43		0.36		0.35		0.37		0.40		1.10		
Victoria	0.11	0.01	0.09	0.00	0.09	0.00									0.04	0.01	0.02	0.00	0.02	0.01	0.03	0.00	
White Pine Village T1	0.74	0.32	0.55	0.22	0.71	0.27	0.65	0.26	0.45	0.16	0.35	0.13	0.39	0.13	0.37	0.13	0.27	0.08	0.40	0.13	0.35	0.13	
White Pine Village T2																							
Winona	0.60	-0.03	0.51	-0.19	0.60	-0.16	0.29	-0.06	0.10	N/A	0.41	-0.24			0.68	-0.08	0.52	-0.13	0.65	-0.08	0.49	0.50	
<b>Total MW/MVAR</b>	<b>139.74</b>	<b>10.47</b>	<b>112.78</b>	<b>13.21</b>	<b>103.31</b>	<b>15.86</b>	<b>135.21</b>	<b>18.41</b>	<b>108.05</b>	<b>7.30</b>	<b>121.98</b>	<b>20.71</b>	<b>132.75</b>	<b>30.78</b>	<b>123.58</b>	<b>23.17</b>	<b>110.19</b>	<b>16.00</b>	<b>148.62</b>	<b>27.59</b>	<b>139.58</b>	<b>40.28</b>	
<b>Total MVA</b>	<b>140.13</b>		<b>113.55</b>		<b>104.52</b>		<b>136.46</b>		<b>108.30</b>		<b>123.73</b>		<b>136.27</b>		<b>125.73</b>		<b>111.35</b>		<b>151.16</b>		<b>145.28</b>		
± Inc/Dec from previous year			-26.58		-9.03		31.94		-28.16		15.43		12.54		-10.53		-14.38		39.81		-5.88		
% Inc/dec from previous year			-19.0%		-8.0%		30.6%		-20.6%		14.2%		10.1%		-7.7%		-11.4%		35.7%		-3.9%		
<b>10-year Ave inc/dec</b>																						<b>2.0%</b>	

10-Year Load Forecast

Interconnection Point	Summer 2025 Forecast		Summer 2026 Forecast		Summer 2027 Forecast		Summer 2028 Forecast		Summer 2029 Forecast		Summer 2030 Forecast		Summer 2031 Forecast		Summer 2032 Forecast		Summer 2033 Forecast		Summer 2034 Forecast		Summer 2035 Forecast	
	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR
Alger Total (Prison)	1.34	0.48	1.34	0.48	1.34	0.48	1.35	0.49	1.35	0.49	1.35	0.49	1.36	0.49	1.36	0.49	1.36	0.49	1.37	0.49	1.37	0.49
Atlantic	4.27	1.22	4.29	1.23	4.31	1.23	4.33	1.24	4.36	1.25	4.38	1.25	4.40	1.26	4.42	1.27	4.44	1.27	4.47	1.28	4.49	1.28
Barnum 1	0.81	0.71	0.81	0.71	0.82	0.71	0.82	0.72	0.82	0.72	0.83	0.72	0.83	0.73	0.84	0.73	0.84	0.74	0.85	0.74	0.85	0.74
Barnum 2	5.98	1.06	6.01	1.07	6.04	1.07	6.07	1.08	6.10	1.08	6.13	1.09	6.16	1.09	6.19	1.10	6.22	1.10	6.25	1.11	6.28	1.11
Barnum 3	5.56	0.74	5.58	0.74	5.61	0.75	5.64	0.75	5.67	0.76	5.70	0.76	5.72	0.76	5.75	0.77	5.78	0.77	5.81	0.77	5.84	0.78
Bayview Total	1.78	0.51	1.79	0.51	1.80	0.51	1.80	0.51	1.81	0.52	1.82	0.52	1.83	0.52	1.84	0.52	1.85	0.53	1.86	0.53	1.87	0.53
Chatham Total	0.81	0.18	0.82	0.18	0.82	0.18	0.82	0.19	0.83	0.19	0.83	0.19	0.84	0.19	0.84	0.19	0.85	0.19	0.85	0.19	0.85	0.19
Delta 1	3.23	-0.41	3.25	-0.41	3.26	-0.41	3.28	-0.41	3.30	-0.41	3.31	-0.42	3.33	-0.42	3.35	-0.42	3.36	-0.42	3.38	-0.42	3.40	-0.43
Delta 2	3.23	-0.61	3.25	-0.61	3.26	-0.61	3.28	-0.62	3.30	-0.62	3.31	-0.62	3.33	-0.62	3.35	-0.63	3.36	-0.63	3.38	-0.63	3.40	-0.64
Elevation Bank 1	3.58	1.21	3.59	1.22	3.61	1.22	3.63	1.23	3.65	1.24	3.67	1.24	3.68	1.25	3.70	1.26	3.72	1.26	3.74	1.27	3.76	1.27
Elevation Bank 2	3.23	0.71	3.25	0.71	3.26	0.71	3.28	0.72	3.30	0.72	3.31	0.72	3.33	0.73	3.35	0.73	3.36	0.74	3.38	0.74	3.40	0.74
Forsyth	1.72	0.30	1.73	0.30	1.73	0.31	1.74	0.31	1.75	0.31	1.76	0.31	1.77	0.31	1.78	0.31	1.79	0.32	1.80	0.32	1.80	0.32
Freeman-34.5kV	1.25	0.96	1.27	0.97	1.30	0.99	1.32	1.01	1.35	1.03	1.38	1.05	1.41	1.08	1.43	1.10	1.46	1.12	1.49	1.14	1.52	1.16
Gwinn Total	2.02	0.42	2.03	0.43	2.04	0.43	2.05	0.43	2.06	0.43	2.07	0.43	2.08	0.44	2.09	0.44	2.10	0.44	2.11	0.44	2.12	0.45
Henry St Total	6.94	2.10	6.97	2.11	7.01	2.12	7.04	2.13	7.08	2.14	7.11	2.15	7.15	2.16	7.19	2.18	7.22	2.19	7.26	2.20	7.29	2.21
Homer Road	3.69	1.97	3.71	1.98	3.72	1.99	3.74	2.00	3.76	2.01	3.78	2.02	3.80	2.03	3.82	2.04	3.84	2.05	3.86	2.06	3.88	2.07
Humbolt Mine Bank 1	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46	1.45	0.46
Humbolt Mine Bank 2	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10	2.95	2.10
Keweenaw	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15	1.35	0.15
KI Sawyer Bank 1	1.67	0.37	1.67	0.37	1.68	0.37	1.69	0.37	1.70	0.37	1.71	0.37	1.72	0.38	1.73	0.38	1.73	0.38	1.74	0.38	1.75	0.38
KI Sawyer Bank 2	4.04	0.99	4.06	0.99	4.08	1.00	4.10	1.00	4.12	1.01	4.14	1.01	4.16	1.02	4.18	1.02	4.20	1.03	4.22	1.04	4.25	1.04
Lake Mine	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Lakehead Rapid River	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43	4.80	0.43
L'Anse Bank 3 (UPPCO)	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43	2.85	0.43
Lincoln Ave Bank 1	3.33	0.33	3.35	0.33	3.37	0.34	3.38	0.34	3.40	0.34	3.42	0.34	3.43	0.34	3.45	0.35	3.47	0.35	3.49	0.35	3.50	0.35
Lincoln Ave Bank 2	3.43	0.34	3.45	0.35	3.47	0.35	3.49	0.35	3.50	0.35	3.52	0.35	3.54	0.35	3.56	0.36	3.57	0.36	3.59	0.36	3.61	0.36
M-38 Total	1.97	1.41	1.98	1.42	1.99	1.43	2.00	1.44	2.01	1.44	2.02	1.45	2.03	1.46	2.04	1.46	2.05	1.47	2.06	1.48	2.07	1.49
Masonville Bank 2	0.34	0.27	0.34	0.27	0.34	0.27	0.34	0.27	0.34	0.27	0.34	0.27	0.34	0.28	0.34	0.28	0.34	0.28	0.34	0.28	0.35	0.28
Masonville Bank 3	1.81	0.35	1.82	0.35	1.82	0.35	1.83	0.35	1.83	0.36	1.84	0.36	1.84	0.36	1.85	0.36	1.85	0.36	1.85	0.36	1.86	0.36
Mead (aka - Verso,Billerud )	33.10	11.11	33.26	11.17	33.43	11.22	33.60	11.28	33.77	11.33	33.93	11.39	34.10	11.45	34.27	11.51	34.45	11.56	34.62	11.62	34.79	11.68
MTU Bank 1	7.57	2.54	7.60	2.55	7.64	2.56	7.68	2.58	7.72	2.59	7.76	2.60	7.79	2.61	7.83	2.63	7.87	2.64	7.91	2.65	7.95	2.67
MTU Bank 2	2.94	0.51	2.96	0.51	2.97	0.51	2.99	0.52	3.00	0.52	3.02	0.52	3.03	0.52	3.05	0.53	3.06	0.53	3.08	0.53	3.09	0.53
Munising Bank 2	3.55	0.04	3.56	0.04	3.58	0.04	3.60	0.04	3.62	0.04	3.63	0.04	3.65	0.04	3.67	0.04	3.69	0.04	3.71	0.04	3.73	0.04
Munising Bank 3 (Mill 2.4 kV Load)	5.99	3.71	6.02	3.73	6.05	3.74	6.08	3.76	6.11	3.78	6.14	3.80	6.17	3.82	6.20	3.84	6.23	3.86	6.26	3.88	6.30	3.90
Munising Bank 4 (Mill 13.8 kV Load)	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20	0.40	0.20
Munising Bank 5	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01	1.33	0.01
Ontonagon Total	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80	2.70	2.80
Osceola Bank 1	8.26	0.06	8.30	0.06	8.34	0.06	8.39	0.06	8.43	0.06	8.47	0.06	8.51	0.06	8.56	0.06	8.60	0.06	8.64	0.06	8.68	0.06
Osceola Bank 2	4.75	0.12	4.77	0.12	4.79	0.12	4.82	0.12	4.84	0.12	4.87	0.13	4.89	0.13	4.92	0.13	4.94	0.13	4.97	0.13	4.99	0.13
Perch Lake T1	1.50	0.21	1.51	0.21	1.52	0.21	1.53	0.22	1.54	0.22	1.54	0.22	1.55	0.22	1.56	0.22	1.57	0.22	1.57	0.22	1.58	0.22
Perch Lake T2																						
Rockland UPPCo	0.21		0.21		0.21		0.21		0.21		0.21		0.21		0.21		0.22		0.22		0.22	
Sawyer Lumber	3.80		3.80		3.80		3.80		3.80		3.80		3.80		3.80		3.80		3.80		3.80	
Seney - Bank 1	0.19	0.02	0.19	0.02	0.19	0.02	0.19	0.02	0.19	0.02	0.19	0.02	0.19	0.02	0.20	0.02	0.20	0.02	0.20	0.02	0.20	0.02
Seney - Bank 2	0.60	0.10	0.60	0.10	0.61	0.10	0.61	0.10	0.61	0.10	0.61	0.10	0.61	0.10	0.61	0.10	0.62	0.10	0.62	0.10	0.62	0.10
Shingleton	1.21		1.21		1.21		1.22		1.22		1.22		1.22		1.23		1.23		1.23		1.24	
Timber Products	2.38		2.38		2.38		2.38		2.38		2.38		2.38		2.38		2.38		2.38		2.38	
Victoria	0.12		0.12		0.12		0.12		0.12		0.12		0.12		0.12		0.12		0.12		0.12	
White Pine Village T1	0.44	0.17	0.44	0.17	0.44	0.17	0.45	0.17	0.45	0.17	0.45	0.17	0.45	0.17	0.45	0.17	0.45	0.17	0.45	0.17	0.45	0.18
White Pine Village T2	0.30	0.05	0.30	0.05	0.30	0.05	0.30	0.05	0.31	0.05	0.31	0.05	0.31	0.05	0.31	0.05	0.31	0.05	0.31	0.05	0.31	0.05
Winona	0.66	0.56	0.66	0.56	0.66	0.57	0.66	0.57	0.66	0.57	0.67	0.57	0.67	0.57	0.67	0.57	0.67	0.58	0.67	0.58	0.67	0.58
<b>Total MW/MVAR</b>	<b>161.61</b>	<b>40.97</b>	<b>162.30</b>	<b>41.16</b>	<b>162.99</b>	<b>41.34</b>	<b>163.69</b>	<b>41.53</b>	<b>164.39</b>	<b>41.72</b>	<b>165.09</b>	<b>41.90</b>	<b>165.80</b>	<b>42.09</b>	<b>166.51</b>	<b>42.28</b>	<b>167.22</b>	<b>42.48</b>	<b>167.94</b>	<b>42.67</b>	<b>168.66</b>	<b>42.86</b>
<b>Total MVA</b>	<b>166.73</b>		<b>167.44</b>		<b>168.15</b>		<b>168.87</b>		<b>169.60</b>		<b>170.32</b>		<b>171.06</b>		<b>171.79</b>		<b>172.53</b>		<b>173.27</b>		<b>174.02</b>	

Worst Feeders Ranking 2021-2023

Feeder	#Ev	SAIDI	SAIFI	CAIDI	#Ev Rank	SAIDI Rank	SAIFI Rank	CAIDI Rank	Total Pts	Total Rank	Circuit Miles	Meters	Meters per Mile
1203	256	194.63	0.4014	484.83	2	1	2	8	13	1	194	2,160	11
1231	361	167.45	0.4099	408.54	1	2	1	10	14	2	200	2,378	12
2733	165	88.71	0.1596	555.71	9	3	9	6	27	3	127	1,035	8
401	222	68.85	0.1905	361.50	3	4	7	13	27	4	152	1,258	8
657	177	48.33	0.1192	405.47	7	6	11	11	35	5	106	1,073	10
719	179	44.68	0.2019	221.29	6	7	6	23	42	6	137	2,024	15
927	124	55.96	0.2754	203.19	13	5	4	28	50	7	146	1,238	9
585	141	27.38	0.1080	253.54	10	11	12	18	51	8	154	1,189	8
1275	114	31.73	0.1055	300.62	15	9	14	16	54	9	57	1,626	29
589	215	40.06	0.2836	141.28	4	8	3	44	59	10	147	1,438	10
583	125	18.93	0.0918	206.27	12	15	17	27	71	11	153	1,440	9
3063	116	16.51	0.0692	238.62	14	17	23	20	74	12	139	1,261	9
1017	174	31.62	0.2397	131.88	8	10	5	51	74	13	144	2,260	16
891	141	15.66	0.1018	153.79	11	18	15	40	84	14	147	1,282	9
1121	182	12.00	0.0835	143.79	5	22	20	43	90	15	89	1,442	16
617	104	22.20	0.1748	126.99	16	12	8	55	91	16	81	1,064	13
1205	83	21.85	0.1586	137.80	26	13	10	46	95	17	66	2,306	35
616	79	19.03	0.0232	821.68	28	14	50	5	97	18	60	408	7
515	92	9.60	0.0440	217.98	20	27	33	24	104	19	95	1,069	11
2735	50	17.22	0.0337	510.89	44	16	38	7	105	20	37	694	19
749	90	12.50	0.0929	134.57	21	20	16	49	106	21	73	615	8
615	103	9.24	0.0562	164.37	17	28	25	38	108	22	61	802	13
747	95	11.38	0.0893	127.37	19	23	19	54	115	23	121	781	6
618	83	8.70	0.0215	403.57	25	29	52	12	118	24	66	515	8
587	67	9.72	0.0524	185.38	34	26	28	33	121	25	59	973	17
403	38	15.29	0.0186	822.73	48	19	54	4	125	26	41	145	4
895	79	12.29	0.1066	115.30	29	21	13	62	125	27	71	1,291	18
987	75	8.68	0.0475	182.88	30	31	31	34	126	28	88	635	7
653	34	10.59	0.0447	236.92	51	25	32	21	129	29			
649	89	6.30	0.0334	188.70	22	40	39	31	132	30	116	631	5
3065	48	11.02	0.0739	149.03	45	24	21	42	132	31	82	1,460	18
323	66	6.88	0.0347	198.25	35	36	37	29	137	32	48	332	7
1405	97	7.65	0.0896	85.43	18	33	18	72	141	33	42	1,195	29
607	64	7.43	0.0488	152.37	37	34	30	41	142	34	14	147	10
717	85	6.65	0.0534	124.39	24	38	26	56	144	35	95	1,530	16
907	89	5.40	0.0334	161.80	23	44	40	39	146	36	59	478	8
863	82	6.90	0.0651	105.93	27	35	24	65	151	37	63	780	12
929	43	6.60	0.0317	208.15	47	39	43	26	155	38	36	321	9
659	8	8.70	0.0325	267.69	68	30	41	17	156	39			
3069	52	8.31	0.0699	118.77	43	32	22	59	156	40	56	1,017	18
663	54	4.29	0.0181	236.67	40	46	56	22	164	41	26	351	14
703	66	4.38	0.0262	166.95	36	45	47	37	165	42	76	1,177	15
1009	71	5.72	0.0530	107.89	33	42	27	64	166	43	50	1,576	31
989	46	5.54	0.0395	140.35	46	43	34	45	168	44	25	255	10
1273	23	6.86	0.0511	134.24	57	37	29	50	173	45	23	170	7
715	18	6.18	0.0324	190.43	61	41	42	30	174	46	0	1	
139	18	3.72	0.0031	1214.87	59	49	66	2	176	47	24	27	1
1125	53	4.26	0.0312	136.62	41	47	45	47	180	48	46	647	14

Worst Feeders Ranking 2021-2023

Feeder	#Ev	SAIDI	SAIFI	CAIDI	#Ev Rank	SAIDI Rank	SAIFI Rank	CAIDI Rank	Total Pts	Total Rank	Circuit Miles	Meters	Meters per Mile
985	71	3.16	0.0245	128.89	32	51	48	52	183	49	38	414	11
203	18	2.64	0.0026	999.36	60	56	67	3	186	50	10	20	2
861	55	3.79	0.0378	100.23	39	48	35	67	189	51	82	1,275	16
1237	23	3.06	0.0146	209.50	56	52	58	25	191	52	41	1,015	25
721	57	2.82	0.0221	127.78	38	53	51	53	195	53	59	1,743	30
1119	74	2.79	0.0316	88.19	31	54	44	70	199	54	42	1,052	25
623	30	3.62	0.0375	96.60	54	50	36	68	208	55	30	1,011	34
599	13	0.94	0.0026	359.59	64	63	68	14	209	56	13	127	10
205	5	0.46	0.0003	1420.77	70	67	72	1	210	57			
705	35	2.53	0.0206	122.70	49	57	53	57	216	58	27	848	32
1199	12	1.61	0.0086	187.49	65	59	61	32	217	59	17	222	13
321	30	2.78	0.0239	116.27	53	55	49	61	218	60	17	161	10
631	52	2.35	0.0281	83.80	42	58	46	73	219	61	76	520	7
133	8	0.06	0.0001	418.54	67	74	75	9	225	62			
864	24	0.83	0.0062	134.90	55	65	63	48	231	63	39	211	5
673	3	0.07	0.0002	347.89	73	72	73	15	233	64	1	5	4
911	3	0.14	0.0006	244.11	74	70	70	19	233	65	3	24	7
707	35	1.56	0.0176	88.55	50	61	57	69	237	66	31	658	21
1123	32	1.60	0.0184	86.99	52	60	55	71	238	67	28	1,344	48
860	16	1.12	0.0093	119.78	62	62	60	58	242	68	23	453	20
655	21	0.87	0.0078	112.81	58	64	62	63	247	69	20	404	20
393	3	0.06	0.0003	179.60	72	73	71	35	251	70			
3061	16	0.81	0.0099	80.95	63	66	59	75	263	71	23	502	21
225	1	0.01	0.0001	178.60	76	76	76	36	264	72			
833	4	0.27	0.0032	83.72	71	69	65	74	279	73			
(blank)	10	0.02	0.0002	105.19	66	75	74	66	281	74			
1403	3	0.44	0.0054	80.90	75	68	64	76	283	75	5	296	62
517	7	0.10	0.0016	60.04	69	71	69	77	286	76	7	96	14
1197	1	0.00	0.0000	116.38	79	77	78	60	294	77	1	7	9
751	1	0.00	0.0001	25.51	78	78	77	78	311	78	7	4	1
319	1	0.00	0.0000	#DIV/0!	77	79	79	79	314	79			

- NOTES:** 1) Includes MEDs but excludes transmission-caused.  
2) This data is not feeder-adjusted when loads were switched to other feeders.  
3) #1 = Worst in each category.

Line Clearance History

		HOU	IR	ONT	ISH	MUN	DEL	UPPCO
<b>2019</b>	Miles of Line Cleared	90	29	32	51	79	94	375
	Cost	\$447,845	\$144,306	\$159,234	\$253,779	\$393,109	\$467,750	\$1,866,023
<b>2020</b>	Miles of Line Cleared	101	11	31	116	56	67	382
	Cost	\$627,977	\$68,393	\$192,745	\$721,240	\$348,185	\$416,579	\$2,375,119
<b>2021</b>	Miles of Line Cleared	149	22	19	109	18	59	376
	Cost	\$1,139,889	\$168,306	\$145,355	\$833,878	\$137,705	\$451,365	\$2,876,497
<b>2022</b>	Miles of Line Cleared	124	33	0	85	44	89	375
	Cost	\$991,081	\$263,755	\$0	\$679,370	\$351,674	\$711,341	\$2,997,221
<b>2023</b>	Miles of Line Cleared	152	8	18	61	69	69	377
	Cost	\$1,292,945	\$68,050	\$153,112	\$518,879	\$586,929	\$586,929	\$3,206,845
<b>5-Yr Ave</b>	Miles of Line Cleared	123	20	20	84	53	76	377
	Cost	\$899,947	\$142,562	\$130,089	\$601,429	\$363,520	\$526,793	\$2,664,341

Pole Inspection History

		HOU	IR	ONT	ISH	MUN	DEL	UPPCO
2019	#Poles Inspected	2,339	381	399	1,360	649	990	6,118
	#Danger/Reject	55	5	6	38	12	39	155
	%	2.4%	1.3%	1.5%	2.8%	1.8%	3.9%	2.5%
	#TREATED	195	27	32	225	109	160	748
	%	8.3%	7.1%	8.0%	16.5%	16.8%	16.2%	12.2%
	COST	\$59,639.44	\$11,454.35	\$6,755.75	\$37,845.76	\$15,341.02	\$26,775.62	\$157,811.94
2020	#Poles Inspected	2001	397	252	1433	642	1141	5,866
	#Danger/Reject	24	7	6	12	3	9	61
	%	1.2%	1.8%	2.4%	0.8%	0.5%	0.8%	1.0%
	#TREATED	385	114	94	230	90	290	1,203
	%	19.2%	28.7%	37.3%	16.1%	14.0%	25.4%	20.5%
	COST	\$49,526	\$15,812	\$10,588	\$35,974	\$20,402	\$32,092	\$164,393
2021	#Poles Inspected	2179	359	267	1368	634	1042	5,849
	#Danger/Reject	24	6	5	23	5	14	77
	%	1.1%	1.7%	1.9%	1.7%	0.8%	1.3%	1.3%
	#TREATED	323	32	77	276	48	136	892
	%	14.8%	8.9%	28.8%	20.2%	7.6%	13.1%	15.3%
	COST	\$55,973	\$13,411	\$11,283	\$39,714	\$14,734	\$24,148	\$159,263
2022	#Poles Inspected	2430	447	321	1437	646	1020	6,301
	#Danger/Reject	23	2	2	11	7	10	55
	%	0.9%	0.4%	0.6%	0.8%	1.1%	1.0%	0.9%
	#TREATED	463	49	100	207	111	116	1,046
	%	19.1%	11.0%	31.2%	14.4%	17.2%	11.4%	16.6%
	COST	\$71,908	\$12,853	\$14,339	\$51,223	\$26,023	\$29,446	\$205,792
2023	#Poles Inspected	2546	449	290	1524	626	1049	6,484
	#Danger/Reject	39	4	2	42	6	25	118
	%	1.5%	0.9%	0.7%	2.8%	1.0%	2.4%	1.8%
	#TREATED	136	40	56	160	53	111	556
	%	5.3%	8.9%	19.3%	10.5%	8.5%	10.6%	8.6%
	COST	\$71,689	\$13,682	\$11,417	\$46,003	\$18,483	\$29,796	\$191,070
5-Yr Ave	#Poles Inspected	2,299	407	306	1,424	639	1,048	6,124
	#Danger/Reject	33	4.8	4.2	25.2	6.6	19.4	93
	%	1.4%	1.2%	1.4%	1.8%	1.0%	1.9%	1.5%
	#TREATED	300.4	52.4	71.8	219.6	82.2	162.6	889
	%	13.1%	12.9%	23.5%	15.4%	12.9%	15.5%	14.5%
	COST	\$61,747	\$13,442	\$10,876	\$42,152	\$18,997	\$28,451	\$175,666

Underground Inspection History

		HOU	IR	ONT	ISH	MUN	DEL	UPPCO
2019	#Cabinets Inspected	226	263	36	264	20	99	908
	Cost	\$15,978	\$17,064	\$2,193	\$16,637	\$1,745	\$6,544	\$60,160
	Cabinets Refinished	39	5	4	8	14	37	107
	Cost	\$11,061	\$1,418	\$1,135	\$2,269	\$3,971	\$10,494	\$30,348
2020	#Cabinets Inspected	654	54	84	363	100	190	1,445
	Cost	\$28,998	\$4,953	\$2,991	\$22,382	\$4,601	\$9,872	\$73,797
	Cabinets Refinished	0	0	0	0	0	0	0
	Cost	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
2021	#Cabinets Inspected	1147	61	176	332	95	381	2,192
	Cost	\$50,439	\$3,907	\$5,861	\$10,691	\$3,607	\$15,026	\$89,529
	Cabinets Refinished	52	1	0	7	4	34	98
	Cost	\$19,996	\$385	\$0.00	\$2,692	\$1,538	\$13,074	\$37,684
2022	#Cabinets Inspected	137	43	121	620	299	159	1,379
	Cost	\$8,974	\$3,185	\$4,142	\$30,598	\$22,047	\$8,670	\$77,615
	Cabinets Refinished	80	14	5	6	8	7	120
	Cost	\$30,884.86	\$5,407.00	\$1,932.06	\$2,316.62	\$3,090.37	\$2,701.18	\$46,332.09
2023	#Cabinets Inspected	574	68	46	167	138	31	1,024
	Cost	\$24,624	\$3,021	\$1,464	\$10,449	\$8,868	\$2,012	\$50,438
	Cabinets Refinished	33	3	0	40	50	1	127
	Cost	\$10,343	\$796	\$0.00	\$12,729	\$15,514	\$398	\$39,779
5-Year Ave.	#Cabinets Inspected	548	98	93	349	130	172	1,390
	Cost	\$25,802	\$6,426	\$3,330	\$18,151	\$8,173	\$8,425	\$70,308
	Cabinets Refinished*	51	6	2	15	19	20	113
	Cost*	\$18,071	\$2,001	\$767	\$5,002	\$6,028	\$6,667	\$38,536

\*The 5-year average does not include 2020 for the Refinished Cabinets, since none were completed that year.

Underground Outage History Compared to All Outages

	Year	# Events	#CUST	SAIDI	SAIFI
<b>All Events (Exc Trans)</b>	2019	2,359	140,593	782.5	2.4
	2020	2,127	107,360	230.9	1.8
	2021	1,792	80,546	249.1	1.4
	2022	2,056	130,224	553.5	2.2
	2023	1,652	80,461	411.5	1.4
	<b>Total</b>	<b>9,986</b>	<b>539,184</b>	<b>2,227.5</b>	<b>9.2</b>
	<b>Average</b>	<b>1,997</b>	<b>107,837</b>	<b>445.5</b>	<b>1.8</b>
<b>UG Dig-Ins</b>	2019	18	130	0.31	0.0022
	2020	13	24	0.06	0.0004
	2021	13	162	0.30	0.0028
	2022	10	15	0.04	0.0003
	2023	4	10	0.04	0.0002
	<b>Total</b>	<b>58</b>	<b>341</b>	<b>0.75</b>	<b>0.0058</b>
	<b>Average</b>	<b>12</b>	<b>68</b>	<b>0.15</b>	<b>0.0012</b>
<b>UG Equip</b>	2019	53	88	0.45	0.0015
	2020	45	78	0.15	0.0013
	2021	38	204	0.72	0.0035
	2022	5	5	0.02	0.0001
	2023				
	<b>Total</b>	<b>141</b>	<b>375</b>	<b>1.33</b>	<b>0.0064</b>
	<b>Average</b>	<b>35</b>	<b>94</b>	<b>0.3</b>	<b>0.0016</b>
<b>UG Other</b>	2019	101	327	1.17	0.0056
	2020	119	243	0.43	0.0041
	2021	67	375	0.63	0.0064
	2022	6	248	0.43	0.0042
	2023				
	<b>Total</b>	<b>293</b>	<b>1,193</b>	<b>2.65</b>	<b>0.0203</b>
	<b>Average</b>	<b>73</b>	<b>298</b>	<b>0.66</b>	<b>0.0051</b>
<b>UG Total</b>	2019	172	545	1.92	0.0093
	2020	177	345	0.64	0.0059
	2021	118	741	1.64	0.0126
	2022	21	268	0.49	0.0046
	2023	4	10	0.04	0.0002
	<b>Total</b>	<b>492</b>	<b>1,909</b>	<b>4.73</b>	<b>0.0325</b>
	<b>Average</b>	<b>98</b>	<b>382</b>	<b>0.95</b>	<b>0.0065</b>
<b>UG % of Total</b>	2019	7.29%	0.39%	0.25%	0.39%
	2020	8.32%	0.32%	0.28%	0.32%
	2021	6.58%	0.92%	0.66%	0.92%
	2022	1.02%	0.21%	0.09%	0.21%
	2023	0.24%	0.01%	0.01%	0.01%
	<b>Total</b>	<b>4.93%</b>	<b>0.35%</b>	<b>0.21%</b>	<b>0.35%</b>
	<b>Average</b>	<b>4.69%</b>	<b>0.37%</b>	<b>0.26%</b>	<b>0.37%</b>

Data above excludes transmission and includes major event days.

**Historical Maintenance Costs**

Year	Overhead \$	Underground \$	Total \$	% UG Cost	OH Miles	UG Miles	OH \$/Mi	UG \$/Mi
2019	\$6,631,532	\$489,806	\$7,121,338	7%	3,374	1,095	\$1,965	\$447
2020	\$5,772,104	\$426,063	\$6,198,167	7%	3,357	1,128	\$1,719	\$378
2021	\$6,516,136	\$671,781	\$7,187,917	9%	3,340	1,160	\$1,951	\$579
2022	\$8,338,676	\$670,732	\$9,009,408	7%	3,323	1,190	\$2,510	\$564
2023	\$8,088,391	\$694,700	\$8,783,091	8%	3,286	1,232	\$2,462	\$564
Average	\$7,069,368	\$590,616	\$7,659,984	8%	3,336	1,161	\$2,119	\$509

Historical line miles not available for 2020, therefore, it is an average of 2019 and 2021.

**By-Foot Estimate Capital Investment Cost Calculation**

**By-foot Costs from Staking Feb. 2024 (see next page)**

<u>System</u>	<u>OH-OH</u>	<u>OH-UG</u>	
1-Phase:	\$37.49	\$28-\$35	<i>Boxes Indicate Inputs</i>
3-Phase:	\$67.85	\$85-\$109	

**Line Clearance Costs**

<u>Prev. Year</u>	<u>Annual Cost</u>	<u>% Pri Sys</u>	<u>Per Mi</u>	<u>Per Ft</u>
Line Clear:	\$3,206,845	100%	\$8,506	\$1.61

**Maintenance Costs**

<u>Annual</u>	<u>2023</u>	<u>% Pri Sys</u>	<u>Per Pri Mi</u>	<u>Per Pri Ft</u>	<u>Cost per Ft</u>
OH Maint:	\$8,088,391	90%	\$3,354.63	\$0.64	\$26.68
UG Maint:	\$694,700	90%	\$771.89	\$0.15	\$6.14
Maint Diff:	\$7,393,691		\$2,582.74	\$0.49	<b>\$20.54</b>

<u>Input</u>		<u>Maint. + Inflation</u>	
<u>Infl. %:</u>	<u>2.00%</u>	<u>Year</u>	<u>Maint Diff</u>
		1	\$20.54
<u>System</u>	<u>Miles</u>	2	\$20.96
OH Pri	2,170	3	\$21.37
OH Sec	596	4	\$21.80
OH Svc	520	5	\$22.24
UG Pri	810	6	\$22.68
UG Sec	45	7	\$23.14
UG Svc	378	8	\$23.60
		9	\$24.07
<u>Expected Project Life (Yrs)</u>	<u>42</u>	10	\$24.55
		15	\$27.11
		20	\$29.93
		25	\$33.04
		30	\$36.48
		35	\$40.28
		40	\$44.47
		45	\$49.10
		50	\$54.21
		55	\$59.86
		60	\$66.09

**Total Cost of Initial Capital & On-gong Maintenance of OH versus UG**

<u>OH-OH</u>	<u>Staking</u>	<u>Initial LC</u>	<u>OH Mt Adder</u>	<u>OH-OH Tot</u>	<u>OH-UG Tot</u>
1-Phase	\$37.49	\$1.61	\$46.27	<b>\$85.37</b>	<b>\$28-\$35</b>
3-Phase	\$67.85	\$1.61	\$46.27	<b>\$115.73</b>	<b>\$85-\$109</b>

## Capital Investment Cost

### Inputs to Staking (2-8-24):

#### 1-ph OH to OH rebuild

U:\Job Packs\Per foot estimates\1PH OH EST COST

Basic: **\$197,398.97/mi = \$37.49/ft**

- Install 1 mile of 1ph 1/0 ASCR, 240' spans, 22-40' class 3 poles, 8 tangent poles, 2 DE pole, 12 various sized angles, 14 anchors/guys, flagging for whole project, 1 person/truck, 2 hours extra labor each day. Removal of 22 poles and 1 mile of wire.
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included.

#### 3-ph OH to OH rebuild

U:\Job Packs\Per foot estimates\3PH OH EST COSTS

Basic: **\$358,273.63/mi = \$67.85/ft**

- Install 1 mile of 3ph 336 ASCR with 1/0 neutral, 240' spans, 22-45' class 3 poles, 10 tangent poles, 2 DE pole, 10 various sized angles, 12 anchors/guys, flagging for whole project, 1 person/truck, 2 hours extra labor each day. Removal of 22 poles and 1 mile of wire.
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included.

#### 1-ph OH to UG conversion

U:\Job Packs\Per foot estimates\1PH EST COST

Basic (design 1): **\$147,635.21/mi = \$27.96/ft**

Worst (design 2): **\$186,831.66/mi = \$35.38/ft**

- **Basic:** Install 1 mile of 1ph 25kV 1/0, 75% plow 25% bore (in 2" conduit), 5 jboxes, 2-40'3 risers. Removal of 22 poles. 10 tangent, 10 various angles, 2 DE, 1 person/truck.
- **Worst:** Install 1 mile of 1ph 25kV 1/0, 50% plow 50% bore (in 2" conduit), 10 jboxes, 2-40'3 risers. Removal of 22 poles. 10 tangent, 10 various angles, 2 DE, 1 person/truck.
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included.

#### 3-ph OH to UG conversion

U:\Job Packs\Per foot estimates\3PH EST COST

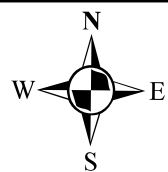
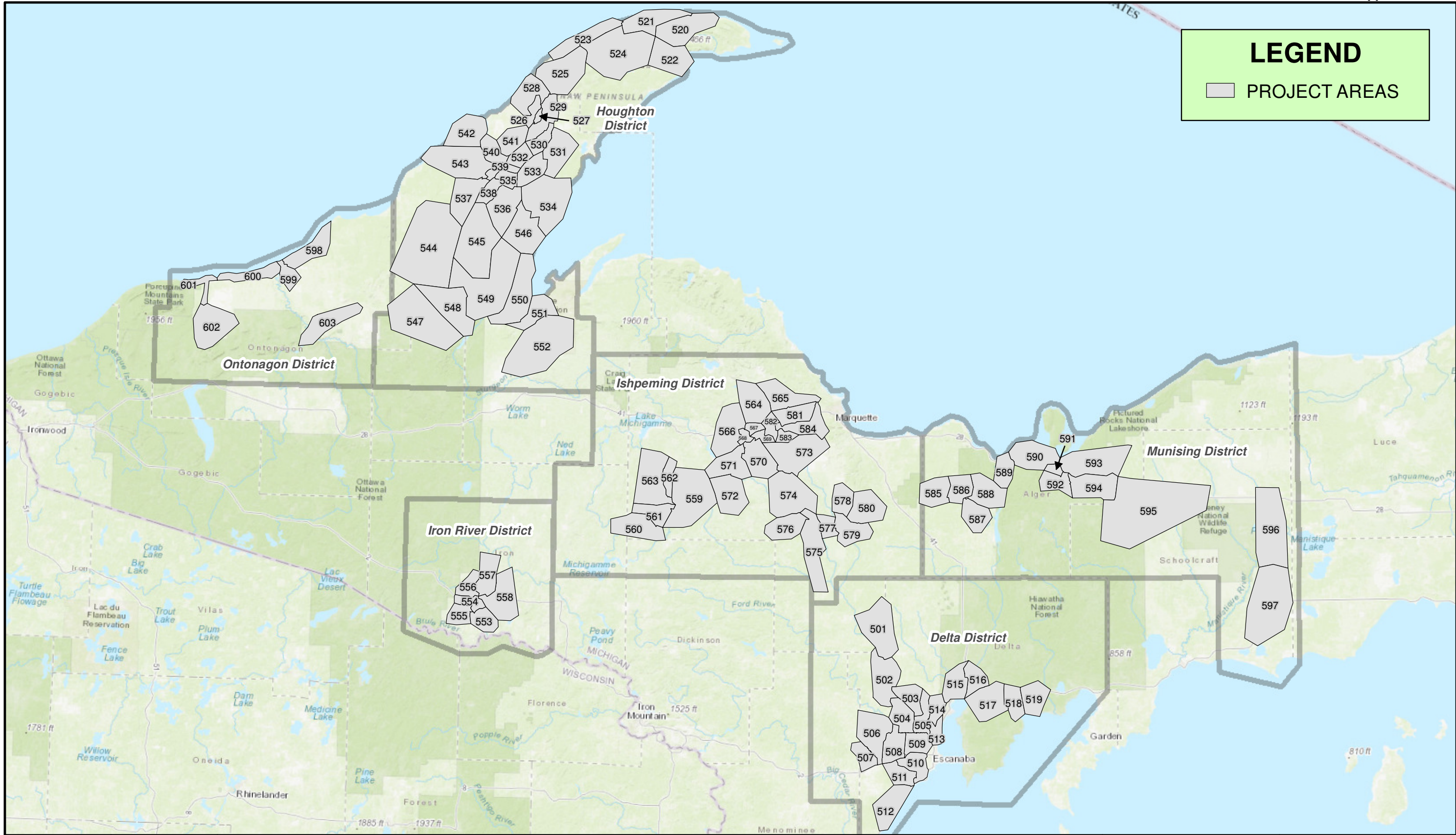
Basic (design 1): **\$448,872.48/mi = \$85.01/ft**

Worst (design 2): **\$580,761.22/mi = \$109.99/ft**

- **Basic:** Install 1 mile of 3ph 25kV 4/0, 75% plow 25% bore (in 6" stick conduit), 5 jboxes, 2-45'3 risers. Removal of 22 poles. 15 tangent, 5 various angles, 2 DE, 1 person/truck.
- **Worst:** Install 1 mile of 3ph 25kV 4/0, 50% plow 50% bore (in 6" stick conduit), 10 jboxes, 2-45'3 risers. Removal of 22 poles. 15 tangent, 5 various angles, 2 DE, 1 person/truck.
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included.

**LEGEND**

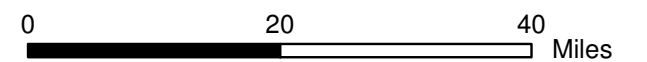
PROJECT AREAS



**UPPCO LINE CLEARANCE PROJECT AREAS**

DATE: 7/30/2024

AUTHOR: JAA



Tentative Line Clearance Project Schedule

LC Area	District	Sch.Year	Line Clearance Area Description	Line Miles
506	ESC	2025	69	40
515	ESC	2025	De Noc	27
516	ESC	2025	Alton 509	14
523	HOU	2025	Eagle Harbor	15
526	HOU	2025	Calumet	23
543	HOU	2025	Redridge	27
544	HOU	2025	Donken	16
555	IR	2025	Stanley Lake	12
572	ISH	2025	581 South	22
586	MUN	2025	M-94 west	23
593	MUN	2025	Lake Shore CR 612	31
601	ONT	2025	Silver City	12
602	ONT	2025	White Pine	24
503	ESC	2026	CR 601 (Boney line)	24
524	HOU	2026	Central	25
528	HOU	2026	Waterworks	18
529	HOU	2026	Trap Rock River	30
533	HOU	2026	Point Mills	15
546	HOU	2026	Portage & Entr'ys	10
554	IR	2026	Iron River	33
561	ISH	2026	Fence River Rd.	23
563	ISH	2026	County Road 601	26
564	ISH	2026	Dead River Basin west	23
565	ISH	2026	Hoist Dam and N. Basin Dr	19
578	ISH	2026	K.I. Sawyer	29
584	ISH	2026	Negaunee 33, Morgan Ht 33, Mather tap, Linburg 33 & Tracy mine	18
596	MUN	2026	Seney	29
597	MUN	2026	Blaney Park	27
600	ONT	2026	M-64	24
603	ONT	2026	Rockland	8
502	ESC	2027	Boney Falls	35
505	ESC	2027	Escanaba River	34
513	ESC	2027	Wells	22
531	HOU	2027	Boot Jack	21
534	HOU	2027	White City	34
536	HOU	2027	Paradise	23
540	HOU	2027	Hancock	31
542	HOU	2027	Canal	15
550	HOU	2027	Baraga	30
575	ISH	2027	Princeton South, and Cataract 33	25
576	ISH	2027	Princeton West	11
579	ISH	2027	Gwinn Rural	29
581	ISH	2027	McClure 33 & Hoist 33	11
582	ISH	2027	Steamplant to N. City Sub	10
594	MUN	2027	Prison and Shingleton	18
598	ONT	2027	Tenmile	19
504	ESC	2028	21st street	25
510	ESC	2028	Ford River	28
514	ESC	2028	Hwy 35	20
521	HOU	2028	Mandan	21
527	HOU	2028	Laurium	23
532	HOU	2028	Dollar Bay	12
547	HOU	2028	M-38 west	23
553	IR	2028	Caspian	18
556	IR	2028	Bates	15
557	IR	2028	Sunset Lake	23

Tentative Line Clearance Project Schedule

LC Area	District	Sch.Year	Line Clearance Area Description	Line Miles
562	ISH	2028	Republic West	19
570	ISH	2028	Ishpeming South	29
574	ISH	2028	Princeton North	27
577	ISH	2028	Gwinn	21
589	MUN	2028	Au Train	13
591	MUN	2028	Munising	14
595	MUN	2028	Clear Lake	11
509	ESC	2029	Portage	29
511	ESC	2029	State Forest North	23
512	ESC	2029	State Forest South (Hwy 35)	24
517	ESC	2029	Township Hailx & 22nd	24
519	ESC	2029	Big Bay De Noc	10
520	HOU	2029	Copper Harbor to Lake Medora	19
522	HOU	2029	Mt. Bohemia and Lac La Belle & 1P to Lake Gratiot	14
525	HOU	2029	Seneca Lake	34
535	HOU	2029	Broemer rd north to Houghton City line	16
539	HOU	2029	Houghton City of	32
548	HOU	2029	Nisula	30
549	HOU	2029	M-38 east	31
552	HOU	2029	Dynamite Hill south & Alberta	25
558	IR	2029	Rogers Loc & East	15
566	ISH	2029	Ely	22
573	ISH	2029	Palmer	17
580	ISH	2029	Little Lake	22
583	ISH	2029	Tracy Mine 33kv.	3
585	MUN	2029	Eben	20
587	MUN	2029	Chatham south	24
590	MUN	2029	Christmas & Grnd Island	22
592	MUN	2029	Wagner	16
599	ONT	2029	Ontongon	20

## Customer-Owned Distributed Generation Process Checklist 7/2021

Customer: \_\_\_\_\_ Acct #: \_\_\_\_\_

Category: \_\_\_\_\_ Date: \_\_\_\_\_

Process Step	Date Completed	UPPCO RP
Application Received		SAP Note:
Application reviewed and forwarded to engineer for approval		Jason Schaen
Verify proposed system kWh production forecast is no greater than recent 12 mo usage.		Jason Schaen
Application and Interconnection Fee Received		Lisa Peterson
Application Approved by Engineer		Dale Hemmila
Information entered into Queue		Jason Schaen
Notice Sent to Metering to Detent Existing Meter		Jason Schaen
No Go Letter or Go Letter and Interconnection Agreement Sent to Customer		Jason Schaen
Inspection Received from Local Electrical Inspector		Jason Schaen
Site commissioning has been completed		Jason Schaen
Request Rate Change / Meter Upgrade		Jason Schaen
Signed Interconnection Agreement Received		Jason Schaen
Interconnection Agreement Countersigned by UPPCO		Jason Schaen
Send Formal In-Service Letter to Customer including copy of signed interconnection agreement		Jason Schaen
Update Queue Spreadsheet with Dates		Jason Schaen
Send Information to Mapping		Jason Schaen
E-mail Kathy Bigger a Copy of Interconnection Agreement for Corporate Records		Jason Schaen
File Copy of Executed Documents in Distributed Generation File Cabinet		Jason Schaen
Notes:		
<a href="U:\Parallel Generation Net Metering\Process Documents\[Process Checklist v7 2021.xlsx]Checklist">U:\Parallel Generation Net Metering\Process Documents\[Process Checklist v7 2021.xlsx]Checklist</a>		



**Distribution and Substation Projected Capital Expenditures by Business Driver**

	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>
<b><u>Distribution</u></b>					
04 Improve Reliability / Load Growth	\$8,523,709	\$8,698,536	\$8,876,948	\$9,059,020	\$9,244,827
05 New Equipment / Equipment Upgrade	\$4,265,000	\$4,352,478	\$4,441,750	\$4,532,853	\$4,625,825
06 New Customer / Service	\$1,662,000	\$1,696,089	\$1,730,877	\$1,766,378	\$1,802,607
07 Contractual / Regulatory / Statutory	\$205,000	\$209,205	\$213,496	\$217,875	\$222,343
08 Special Projects	\$0	\$0	\$0	\$0	\$0
<b>Distribution Subtotal</b>	<b>\$14,655,709</b>	<b>\$14,956,307</b>	<b>\$15,263,070</b>	<b>\$15,576,126</b>	<b>\$15,895,602</b>
<b><u>Substations</u></b>					
03 Facility / Land	\$750,000	\$0	\$0	\$0	\$0
04 Improve Reliability / Load Growth	\$0	\$0	\$0	\$0	\$0
05 New Equipment / Equipment Upgrade	\$2,150,063	\$2,959,545	\$3,020,247	\$3,082,195	\$3,145,412
08 Special Projects	\$0	\$0	\$0	\$0	\$0
<b>Substation Subtotal</b>	<b>\$2,900,063</b>	<b>\$2,959,545</b>	<b>\$3,020,247</b>	<b>\$3,082,195</b>	<b>\$3,145,412</b>
<b>Total Distribution &amp; Substation</b>	<b>\$ 17,555,772</b>	<b>\$ 17,915,852</b>	<b>\$ 18,283,318</b>	<b>\$ 18,658,320</b>	<b>\$ 19,041,015</b>

**System Hardening and Reliability Projects (SHARP)**

Distribution SHARP CapEx Projects > \$50,000				RASCL	Cust	Miles	2025 Est.
1	East	1000.04.02	DLT - OH-UG DELTA 589 Fuller Park rebuild	RA	14	1.1	\$225,000
2	East	1000.04.02	ISH - Barnum substation feeder exit rebuild	R	4,533	0.4	\$150,000
3	East	1000.04.02	ISH - OH-OH BARNUM 133/139 Negaunee sub retirement	A	28	0.6	\$150,000
4	East	1000.04.02	ISH - OH-OH FREEMAN 203 CR 480 rebuild	RA	11	1	\$150,000
5	East	1000.04.02	ISH - OH-UG BARNUM 1231 N. Rose Street	RA	19	0.4	\$125,000
6	East	1000.04.02	ISH - OH-UG FORSYTH 2733 Little Shag Road-South Tap	RA	51	1.3	\$290,000
7	East	1000.04.02	ISH - OH-UG PERCH LAKE 401 Part 1 Horseshoe Lake	RA	177	1.3	\$250,000
8	East	1000.04.02	ISH - OH-UG BARNUM 1231 Lake Breeze Lane	RA	21	1	\$290,000
9	East	1000.04.02	ISH - OH-UG FORSYTH 2733 Escanaba River UG Cable Replacement	RA	123	0.4	\$175,000
10	West	1000.04.02	HOT - OH-UG KWN 927 Mainline hardening	RS	1,234	1.5	\$150,000
11	West	1000.04.02	HOT - UG-UG ATL 891 Liminga Rd replacement part 1	ASL	468	5	\$750,000
12	West	1000.04.02	IRV - OH-UG LIN 3063 Sunset Lake tie	RA	318	2	\$600,000
13	West	1000.04.02	HOT - UG-UG Replace underwater Canal crossings	AL	6,587	0.5	\$108,209
14	UPCO	1000.04.02	UPPCO - Cutout Replacement	RAS	n/a	n/a	\$900,000
15	UPCO	1000.04.02	UPPCO - 2024 Carryover Costs	n/a	n/a	n/a	\$250,000
16	UPCO	1000.04.01	UPPCO WIDE URD Replacement (tied to unforeseen failures)	RA	UNK	UNK	\$235,000
17	UPCO	1000.04.01	MID-CAP SYS. HARDENING, OH TO URD CONV, AND COPPER REPLC (\$50k-\$100k)	RA	UNK	UNK	\$325,500
18							
19							
20							
21							
22							
23							
24							
25							
<b>Total SHARP CapEx</b>					<b>13,584</b>	<b>16.5</b>	<b>\$5,123,709</b>

*RASCL: R – Reliability/Storm Hardening A – Age & Condition S – Safety C – Compliance/Voltage L – Load/Capacity*

**Districts:** HOT-Houghton, IRV-Iron River, ONT-Ontonagon, ISH-Ishpeming, MUN-Munising, DLT-Delta (Escanaba)

**Substation CapEx**

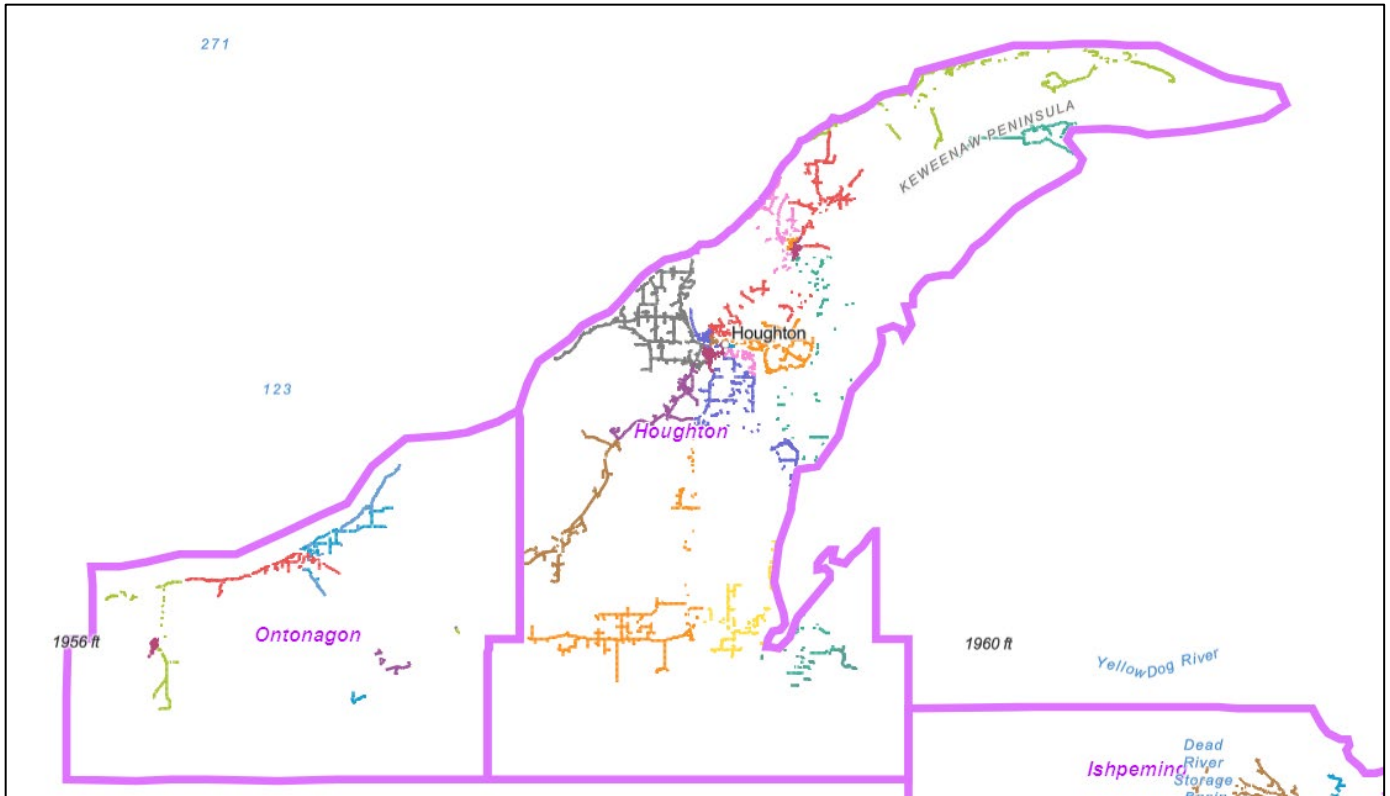
<b>Substation CapEx &gt; \$100,000</b>			<b>2026 Est.</b>
1	2000.03.01	18th Road Substation	\$500,000
2	2000.03.01	CR 480 Substation	\$250,000
3	2000.05.05	Osceola Add 12.5KV Feeder CJ20N Complete 4000090260	\$26,220
4	2000.05.08	328A Voltage Regulators 100wk lead time	\$209,762
5	2000.05.08	Barnum Add 2 Feeders	\$314,643
6	2000.05.08	Chatham Replace Aging Transformer (UHV-1733) - Mfg 1964 - New 5/7 MVA	\$293,667
7	2000.05.08	Delta RTU and R&C upgrade (Replace 4 351R's)	\$314,643
8	2000.05.08	M38 - 138/12.5KV XFMR and High side protection	\$209,762
9	2000.05.08	Ontonagon Bank 2 (UHV-1220) Replace Aging Transformer - MFG 1967 - New 5/7 MVA	\$293,667
10	2000.05.08	Delta Bank 1 Transformer High Side Protection Equipment 4000088098	\$209,762
11	2000.05.08		
12	2000.05.08		
13	2000.05.08		
14	2000.05.08		
15	2000.05.08		
<b>Total Substation Capital</b>			<b>\$2,622,126</b>

**Distribution and Substation Projected Operations & Maintenance Expenditures by FERC Account**

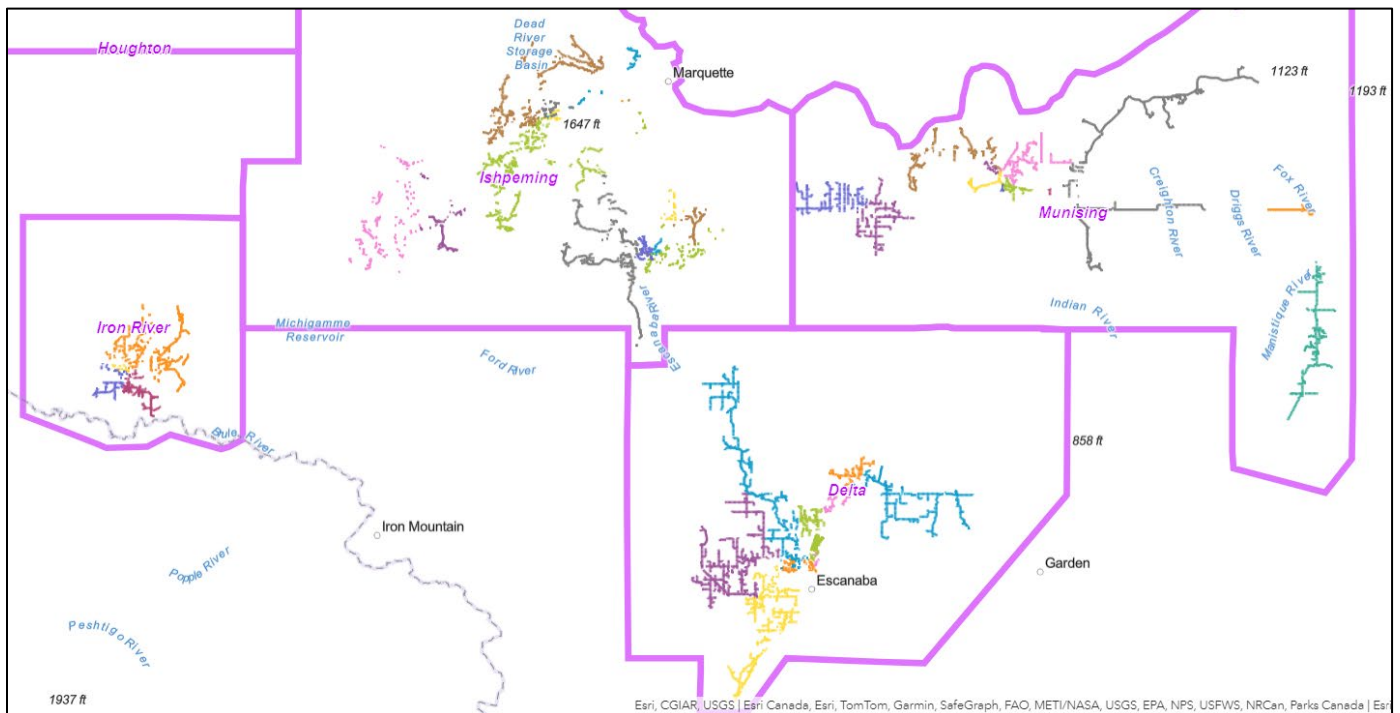
<b>FERC O&amp;M Account</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>
582000 Dist-Station Expenses	\$1,321,143	\$1,387,201	\$1,456,561	\$1,529,389	\$1,605,858
583000 Dist-Overhead Line Expenses	\$82,581	\$86,710	\$91,045	\$95,598	\$100,378
584000 Dist-Underground Line Expenses	\$21,746	\$22,833	\$23,975	\$25,173	\$26,432
585000 Dist-Str Lighting & Signal Sys	\$8,167	\$8,575	\$9,004	\$9,454	\$9,927
586000 Dist-Meter Expenses	\$1,017,707	\$1,068,593	\$1,122,022	\$1,178,123	\$1,237,029
588000 Dist-Miscellaneous Distribution	\$2,659,386	\$2,792,356	\$2,931,973	\$3,078,572	\$3,232,501
589000 Dist-Rents	\$124,908	\$131,154	\$137,711	\$144,597	\$151,827
592000 Dist-Maint of Station Equipment	\$921,923	\$968,019	\$1,016,420	\$1,067,241	\$1,120,603
593000 Dist-Maint of Overhead Lines	\$9,034,382	\$9,486,102	\$9,960,407	\$10,458,427	\$10,981,348
594000 Dist-Maint of Underground Lines	\$951,909	\$999,504	\$1,049,480	\$1,101,954	\$1,157,051
595000 Dist-Maint of Line Transformer	\$580,985	\$610,034	\$640,535	\$672,562	\$706,190
596000 Dist-Maint of St Lighting & Signal Sys	\$7,640	\$8,022	\$8,423	\$8,845	\$9,287
597000 Dist-Maint of Meters	-\$49,079	-\$51,533	-\$54,110	-\$56,815	-\$59,656
598000 Dist-Maint of Misc Distribution	\$14,204	\$14,914	\$15,659	\$16,442	\$17,265
<b>Total Distribution &amp; Substation</b>	<b>\$16,697,602</b>	<b>\$17,532,482</b>	<b>\$18,409,107</b>	<b>\$19,329,562</b>	<b>\$20,296,040</b>

Interim Hosting Capacity Map

The following maps indicates UPPCO's three-phase system. The colors indicate the conductor size. UPPCO staff will use these maps with prospective developers to help determine optimal locations for DG.




UPPCO Houghton and Ontonagon Districts



UPPCO Iron River, Ishpeming, Munising, and Delta Districts

Interim Hosting Capacity Map  
Legend

**3PH OH**

-  477 ACSR
-  336 ACSR
-  4/0 B CU
-  3/0 B CU
-  2/0 B CU
-  4/0 ACSR
-  1/0 B CU
-  1/0 CW
-  1/0 WP CU
-  3/0 ACSR
-  1 B CU
-  2/0 ACSR
-  2 A CW
-  1/0 ACSR
-  2 B CU
-  2 WP CU
-  OTHER

**3PH UG**

-  750 AL STR
-  500 AL STR
-  350 AL STR
-  4/0 AL STR
-  OTHER

**Substation Inspection Report**

To complete a proper substation inspection, refer to the Substation

Inspection form guide, BWP-1303

A "√" represents a successful inspection ( a )

An "X" specifies follow-up ( r )

Station: BARNUM

Abbr: BRM

Date:

Time:

Temp:

Inspector:

Substation Supvr. Ishpeming

Ownership Type: UPPCO

Control House		√	X	Bus Work, Switches		√	X
1	Building, Appearance, Inside/Outside			15.2	Observe bushings for flash marks, cracks, chips		
1.2	Inspect Control Circuitry			15.3	Verify PT fuses are intact and no tails hanging		
2	Heat, Ventilators, Air Cond., Temperature			16	Potheads, Cables		N/A
3	Battery, Rack & Area - General Appearance			17	Leads & Connections		
3.1	Proper Level of Electrolyte			<b>Fence, Grounds, Structures</b>			
3.2	Terminals & Connectors Secure and Corrosion Free			18	Buildings		
4	Switchboard Lites			19	Fence, Gates, Locks, Signs, Sabotage or Vandalism		
5	Spare Swbd. Fuses, Lites, & Hold Cards (ATC & UPPCO)			20	Washouts, Weeds, Landscaping, Shrubs, Erosion,		
6	Relay Targets - Record under Remarks, Reset			21	Foundations		
7	A.C. & D.C. Lights			22	Yard Lites & Posts - Test Lights		
8	Door Operation (Inc. Panic Hdw.)			23	Ground Wires		
9	Telephone - Check Ringer (Indoor & Outdoor) Correct No's			24	Conduit & Fittings		
<b>Bus Work, Switches</b>				25	Underground Cable		
10	S&C Circuit Switches, Circuit Interrupters-Gas-Target		N/A	26	Paint		
11	Switch Motor Operators		N/A	27	Lightning Mast		
12	Switches - Contacts Fully Closed			28	Oil Leaks - Explain in Remarks		
13	Switch Locks & Signs			<b>Accessories</b>			
14	Insulators, Bus Supports			29	Cabinets & Boxes, ID Tags		
15	Arrestors, Current & Potential Transf.			30	Switch Sticks & Boxes		N/A
15.1	Terminals & Connectors Secure and Corrosion Free			31	Feeder Metering Panels - ID Tags		

**Transformers**

HV# (Power & Instrument Transformers -if applicable)	Bank#	(32) Maintank Pressure (+, -, 0)	(33) Nitrogen Tank Pressure - Lbs. (Turn off if below 200 lbs.)	(34) Oil Temp. (Reset if over 70) Note Drag Hand Ind.	(35) Winding Temp.	(36) Bushings - Oil Level (X if low) & CT Bushing	(37) Oil Leaks - (S-Serious, M-Minor)	(38) Oil Level (X if low)	(39) Gauges (X if broken)	(40) Fans, Pumps (R if on)	(41) Paint / Foundation
UHV-4001	1										
UHV-6150	2				N/A						
10273529	3										

**OCB, VCB, OCR, GCB, VCR**

B#	Line/ FDR#	(42) Operator, Oil or Air Pressure - Lbs. Gas	(43) Operation Counter Rdg. (Update Card)	(44) Oil Leaks - (S-Serious, M-Minor)	(45) Oil Level (X if low)	(46) Bushings - Oil Level (X if low) & CT Bushings	(47) Heaters (On-Off)	(48) Compressor Hour Rdg. (Record Hours)	(49) Cabinet Interior (X needs attention)	(50) Paint	(51) Foundation
UB-1203	1203	N/A						N/A			
UB-1205	1205	N/A						N/A			
UB-2215	1213	N/A		N/A	N/A			N/A			
UB-2216	1281	N/A		N/A	N/A			N/A			
UB-2217	133	N/A		N/A	N/A			N/A			
UB-2218	139	N/A		N/A	N/A			N/A			
UB-1237	1237	N/A						N/A			
UB-0653	1231	N/A						N/A			

**Motor Operated Switch**

B#	Line/ FDR#	(42) Operator, Oil or Air Pressure - Lbs. Gas	(43) Operation Counter Rdg. (Update Card)	(44) Oil Leaks - (S-Serious, M-Minor)	(45) Oil Level (X if low)	(46) Bushings - Oil Level (X if low) & CT Bushings	(47) Heaters (On-Off)	(48) Compressor Hour Rdg. (Record Hours)	(49) Cabinet Interior (X needs attention)	(50) Paint	(51) Foundation
MO-425	1221	N/A	N/A	N/A	N/A	N/A		N/A		N/A	N/A

**Capacitors**

Bank #	Unit#	(52) Blown Fuse	(53) Bulged Tanks	(54) Oil Leaks - (S-Serious, M-Minor)	(55) Danger Signs						
N/A											

**Voltage Regulators**

R# & FDR #	Phase	(56) Operation Counter	(57) Drag Hand Min	(58) Drag Hand Spot	(59) Drag Hand Max	(60) Volts	(61) Amps	(62) Oil Level/Leaks (X if low)	(63) Temperature (X if hot)	(64) Control	(65) Paint / Foundation
UR-1734, 1237	A										
UR-1735, 1237	C										
UR-1736, 1237	B										
UR-5419, 1231	B										
UR-5420, 1231	C										
UR-5421, 1231	A										
UR-5416, 1203	B										
UR-5417, 1203	C										
UR-5418, 1203	A										
UR-5410, 1205	B										
UR-5411, 1205	C										
UR-5412, 1205	A										

**Circuit Switcher**

CS #	(66) Operation Counter	
CS-0725		
CS-131		
CS-127		

Device #	Inspector Comments

**Display Preventive Maintenance Order 400089926: Central Header**



Order

TRFMR POWER TEST - ST-BRM-BANK01-XF01

Sys.Status REL PCNF PRT NMAI PRC SETC

- HeaderData
- Operations
- Components
- Costs
- Objects
- Additional Data
- Location
- Planning
- Control
- Enhancement

**Person responsible**

PlannerGrp <input type="text" value=""/> / <input type="text" value="1026"/>	Notifctn <input type="text" value=""/>
Mn.wk.ctr <input type="text" value="26-SUBST"/> / <input type="text" value="1026"/> Substation Crew I...	Costs <input type="text" value="0.00"/> USD
	PMActType <input type="text" value="PFS"/> SUB XFMR PF T...
	SystemCond. <input type="text" value=""/>

**Dates**

Bsc start <input type="text" value="03/14/2024"/>	
Basic fin. <input type="text" value="03/14/2024"/>	Revision <input type="text" value=""/>

**Reference object**

Func. Loc. <input type="text" value="ST-BRM-BANK01-XF01"/>	TRANSFORMER-1-BARNUM-ABC	
Equipment <input type="text" value="10001555"/>	TRANSFRMR-PWR; KUHLMAN ; 12-16-22.4 MVA;	

**First operation**

Operation <input type="text" value="TRFMR POWER TEST - ST-BRM-BANK01-XF01"/>	CcKey <input type="text" value="Calculate duration"/>	
WkCtr/Plnt <input type="text" value="26-SUBST"/> / <input type="text" value="1026"/>	Ctrl key <input type="text" value="SM01"/>	Acty Type <input type="text" value="LSTE01"/> <input type="checkbox"/> PRT
Work durtn <input type="text" value="0.0"/> HR	Number <input type="text" value="0"/>	Oprtn dur. <input type="text" value="0.0"/> HR <input type="checkbox"/> Comp.
Person. no <input type="text" value="0"/>		

Distribution Plant Depreciation Table  
Per Case U-21513

FERC ACCOUNT		Proposed Ave. Life
361.00	Land Rights	60
361.00	Substation Structures & Improvements	56
362.00	Station Equipment	44
364.00	Poles, Towers & Fixtures	49
365.00	Overhead Conductors & Devices	56
367.20	Underground Conductors & Devices	40
368.00	Line Transformers	45
369.10	Overhead Services	56
369.20	Underground Services	56
370.00	Meters	15
371.00	Installations on Customers' Premises	30
373.00	Street Lighting & Signal Systems	30