

**Final Report
Utility Distribution Audit of
DTE Energy**

Part Two

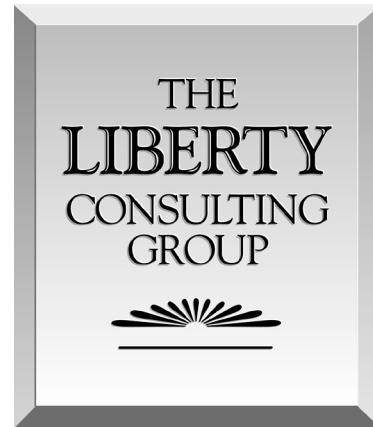
Presented to the:

*Michigan Public
Service Commission*



Presented by:

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September 23, 2024

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Table of Contents

Chapter I – Distribution System Organization, Management and Processes 1

- A. Background 1
- B. Executive Oversight 3
 - 1. Findings 3
 - 2. Conclusions 4
 - 3. Recommendations 4
- C. Electric Operations Organization 4
 - 1. Findings 4
 - 2. Conclusions 14
 - 3. Recommendations 15
- D. Planning 16
 - 1. Findings 16
 - 2. Conclusions 24
 - 3. Recommendations 26
- E. Infrastructure Program Management and Expenditures 26
 - 1. Findings 26
 - 2. Conclusions 29
 - 3. Recommendations 29
- F. Asset Management 29
 - 1. Findings 29
 - 2. Conclusions 30
 - 3. Recommendations 31
- G. Inspection and Maintenance 31
 - 1. Findings 31
 - 2. Conclusions 40
 - 3. Recommendations 43
- H. System Operations 45
 - 1. Findings 45
 - 2. Conclusions 46
 - 3. Recommendations 46
- I. Forestry 47
 - 1. Findings 47
 - 2. Conclusions 52

3.	Recommendations.....	53
J.	Managing Work Performance.....	53
1.	Findings.....	53
2.	Conclusions.....	53
3.	Recommendations.....	54
K.	System Records.....	54
1.	Findings.....	54
2.	Conclusions.....	55
3.	Recommendations.....	55
Chapter II – DGP Reliability Programs		56
A.	Background.....	56
B.	Overall DGP Programs, Measures, Activities, and Costs Observations.....	56
C.	DGP Summary	59
1.	Plan Goals and Pillars	59
2.	Reliability Performance Drivers	61
3.	Capital Investments.....	62
4.	DTE’s Reliability Model.....	63
5.	Conclusions.....	67
6.	Recommendations.....	68
D.	Pillar 1: Tree Trimming	68
1.	Background.....	68
2.	DGP Measures	69
3.	Conclusions.....	69
4.	Recommendations.....	69
E.	Pillar Two: Infrastructure Resilience and Hardening	70
1.	Background.....	70
2.	DGP Measures	70
3.	Conclusions.....	75
4.	Recommendations.....	76
F.	Pillar Three: Infrastructure Redesign and Modernization	78
1.	Background.....	78
2.	DGP Measures	78
3.	Conclusions.....	82
4.	Recommendations.....	84

G. Pillar Four: Technology and Automation	86
1. Background	86
2. DGP Measures	86
3. Conclusions	92
4. Recommendations	94
Chapter III – Emergency Planning and Response	95
A. Background	95
B. Findings	96
1. Emergency Preparedness and Response Plan and Organization	96
2. Pre-Event Planning	99
3. Event History and Restoration	106
4. Wire Down Process and Performance	110
5. Restoration Budgeting	118
6. Compliance with Reliability and Restoration Metrics	119
C. Conclusions	121
1. Conclusions – ERP Plan and Organization	121
2. Conclusions – Pre-Event Planning	122
3. Conclusions – Event History and Restoration	123
4. Conclusions – Wire Down Process and Performance	123
5. Conclusions – Restoration Budgeting	124
6. Conclusions- Compliance with Reliability and Restoration	124
D. Recommendations	124
1. Recommendations – ERP Plan and Organization	124
2. Recommendations – Pre-Event Planning	125
3. Recommendations – Event History and Restoration	125
4. Recommendations – Wire Down Process and Performance	126
5. Recommendations – Restoration Budgeting	126
6. Recommendations - Compliance with Reliability and Restoration Metrics	127
Chapter IV – Outage Communications	128
A. Background	128
B. Findings	129
1. Call Center & Digital Channels	129
2. Key Accounts	138
3. Corporate Communications	139

4. Government & Community Relations 142

5. Estimated Times of Restoration..... 144

C. Conclusions..... 146

D. Recommendations..... 151

Chapter I – Distribution System Organization, Management and Processes

A. Background

This engagement’s Part 2 consisted of an examination of distribution system management, programs, processes, and standards driving planning and execution of reliability-focused investments, and guiding inspection and maintenance activities. We examined these elements for sufficiency in meeting present and future system needs safely and reliably, and in recognition of changing weather conditions, loads, and the need for equitable treatment among service area communities and regions. The reliability programs captured in the 2023 Distribution Grid Plan (“DGP”) that DTE Electric (“DTE”) filed with the Michigan Public Service Commission (“MPSC” or “Commission”) on September 29, 2023 formed a primary focus of Part 2 work.

The organizations that this Chapter addresses, their structure, and resources, their alignment of responsibilities, and the processes, methods, systems, and activities by which they fulfill those responsibilities bear strongly on maintaining a safe and healthy system and for planning additional or changed measures for sustaining and for improving it. Securing improvement has particular importance for DTE, whose plans include very large investments and other expenses designed to move it very far forward in reliability performance. DTE’s DGP sets an extremely aggressive outage reduction goal that will move it from well into the fourth quartile to the middle of the second quartile. Achieving it means reducing outage minutes measured by the commonly-used System Average Interruption Duration Index (“SAIDI”) by almost two thirds (64 percent) for future years that experience average numbers of days when extreme weather disrupts the system; *i.e.*, Major Event Days, or (“MEDs”). The targeted reduction in outage frequency under the also commonly used System Average Interruption Frequency Index (“SAIFI”) requires a less extreme but still very significant 27 percent reduction in numbers of outages from the baseline level in normal weather years.

The organizations we examine in this chapter, along with their processes, methods, systems, and activities will also prove critical in executing the plans that DTE’s DGP proposes. Growth in work that drives the increase in expenditures will require carefully designed and rigorously executed means for continuing to inspect, maintain, and repair systems and equipment sufficiently to minimize needs for expensive replacement. Organizations we address in this chapter will also have to operate under well-structured means for prioritizing work based on priorities that take measured account of asset health. These organizations will also have significant responsibility for performing reliability program work at levels sufficiently increased to add complexity to already substantial needs for planning and executing field installations.

At the same time, DTE will need to advance the introduction of technology growing in use in the industry to provide real time information about system conditions and to control its configurations to perform optimally in normal conditions and respond quickly and effectively in adverse circumstances. Technology introduction challenges also include the development of systems that will support more efficient and timely dispatch of and support for field resources, again in circumstances ranging from the normal to the extreme. Increasing the ability to collect and analyze

information about the system and its needs is also important for planning to meet future investment needs and for prioritizing O&M activities to respond first to greatest areas of operational risk.

Even with substantial improvement in reliability performance, responses to upset conditions and outages will remain significant and particularly challenging for an electricity distribution utility, like DTE. For example, a very large portion of its system will remain served by ungrounded 4.8kV facilities that present significant safety risks. Their configuration leaves them energized in many cases when wires come down due to vegetation contacts, equipment failures, or third-party causes, such as motor vehicle hits. These legacy facilities, built to standards that have increased since, have lower strength, in addition to their significant age. Even after investments to convert the 4.8kV circuits planned for conversion through 2028, DTE anticipates that it will take another \$20 to \$25 billion dollars, a staggering sum, to convert the remaining 16,000 overhead miles of these circuits by 2040. Even before considering other system needs that will remain after 2028, the schedule for completing full 4.8kV conversion alone will require yearly costs equal to or greater than the yearly costs of investments to serve all system needs, as the DGP charts them. Addressing reliability and safety thus does not comprise an interlude for DTE, but a long journey that has significant execution risk and potentially very large electricity price consequences.

This chapter describes and presents the results of our review of the organizations that must perform effectively to meet needs like those just described. We focused on the structure and processes for forming plans, making decisions, and conducting utility operations. We considered in performing our examination whether management:

- Provides for adequate responsibility, accountability, and resources for identifying system reinforcement, addition, and reliability improvement needs
- Assesses the condition, resiliency and reliability of electric infrastructure and regularly employs comprehensive, objective, and quantifiable performance measures
- Employs sufficient numbers of employee and contractor resources to ensure sufficient attention to the condition of those facilities, their performance, identification of gaps, and planning for means to address such gaps.

The organization responsible for distribution system operations and maintenance should employ a structure, responsibility and accountability alignment, and resources sufficient to support timely and thorough identification, planning, budgeting, execution, control, performance measurement, and other activities required for long-term cost effective, reliable, and safe operation of the system. Leaders, executives and managers, and groups responsible for assessing the condition and needs of electric infrastructure should regularly employ comprehensive, objective, and quantifiable performance measures.

We examined where overall executive responsibility for system needs and operations lies. We assessed specific roles, responsibilities, accountabilities, and resources of groups having responsibility for planning, budgeting, installing, operating, inspecting, maintaining, and retiring system facilities. We learned how operations-related functions are organized and examined the nature and reasons for recent material changes. We charted and reviewed resource levels for major functions. We determined the metrics that leadership uses to assess system reliability, performance, and condition in making plans for additions, reinforcements, and enhancements.

B. Executive Oversight

1. Findings

DTE shares executive oversight of the planning, engineering, design, construction, operation, maintenance and restoration for distribution operations between three Vice Presidents, each of whom report to the President and COO of DTE Electric. The VP of Distribution Operations Engineering and the VP of Distribution Operations work together closely to oversee the planning, engineering, and control room and field operations of the electric grid and the supply of electricity to DTE customers. The Vice Presidents of Distribution Engineering and Electric Distribution Operations co-lead the assembly and analysis of data and Key Performance Indicators that inform a multi-layered review process.

The operational oversight process begins with a daily leadership call among the Vice President of Distribution Operations and the functional Directors and Managers in his organization, including those responsible for control room and field (Regional Customer) operations, as well as emergency preparedness and response. Real time system health, operating response metrics, dispatch effectiveness and any ongoing critical outages typify discussion content.

Operating Directors follow the daily calls with a weekly meeting to assemble and finalize Distribution Operations scorecard metrics that include public and employee safety, system status and asset health, emergency preparedness and restoration status, operational cost, productivity, reliability, and major reliability program and project management milestone progress. The Vice President of Distribution Operations then chairs a weekly assembly (the Electric Operational Review) of approximately 30 senior leaders, including each of the Electric Vice Presidents to review those operational goals and results. These meetings include:

- Review various Key Performance Indicators for initiative progress and success
- Revise and refine workplans to deliver improvement
- Focus on data-driven comparisons and results.

Those metrics and course corrections are in turn passed along with data from the other DTE lines of business to a weekly corporate-wide Operational Review that includes the CEO and direct reports. DTE's Storm Emergency Preparedness and Restoration organization has received significantly heightened executive attention since 2020. An experienced and qualified Director within the Distribution Operations organization heads this preparedness organization. The organization comprises a relatively large group of engineers, analysts, meteorologists and IT professionals who have responsibility for six critical functions, each led by a senior and operationally experienced Manager. The functions comprise:

- Public safety and emergency preparedness, including mutual assistance liaison responsibilities and leadership and coordination of wires-down response measures
- Event management, focusing on improvement of the life cycle of outage events from customer interruption through dispatch, monitoring and improving the restoration process
- Productivity, applying industrial engineering principles and practices, dashboard formation and monitoring processes to improve control rooms situational awareness and restoration performance

- Strategy and change management, improvement of initiative tracking and internal communications
- Regional Incident Command Structure (“ICS”) development and support – transitioning the enterprise level ICS methodology to the four distribution regions
- Damage assessment, developing staff capabilities and IT tools to gather, analyze and use damage assessment information and images in restoration prioritization and resourcing decisions.

Seasoned operations leaders head these six functions, all well-staffed. Their work has proven central to DTE’s storm performance improvement efforts. Group formation and staffing reflect executive leadership’s renewed and reemphasized focus on the critical importance of preparedness before and effective and swift restoration after storms.

2. Conclusions

1. The DTE leadership organization is appropriately structured and engaged in addressing the reliability challenges that face DTE.

Daily and weekly reviews at the operating leadership level are followed by other weekly review sessions involving top management, ultimately including the President of DTE Electric and peers. In individual and group interviews and interactions, Engineering and Operations executives articulated and demonstrated sound strategic and process-oriented alignment, integration and cooperative governance in all appropriate operational areas. We found evidence of teamwork, clear and real-time communication, rapid escalation through layers of executive management, and data driven decision making.

We found the DTE executive team apparently well informed, knowledgeable and well-focused on public safety and reliability improvement using a comprehensive set of metrics and frequent, detailed and structured operating views to track initiative progress and performance results. While both the VP of Distribution Operations and the VP of Distribution Operations Engineering were replaced by other individuals during the course of the audit, the new executives demonstrated both experience and detailed knowledge in their areas of responsibility.

3. Recommendations

We have no recommendations regarding Executive Oversight.

C. Electric Operations Organization

1. Findings

We examined the overall structure of the electric operations organization and changes in resources generally from 2019 through 2023, unless noted. We considered how those changes have corresponded to work level changes in recent years to identify whether there appeared to be any system issues causing or risking resource shortages and to determine whether any apparent areas of likely shortage may occur under work levels contemplated by DTE’s DGP.

a. Operations Groups

DTE has assigned a large number of director-level individuals providing for reasonably narrowly focused functions and activities. Twelve Distribution Operations Director-level organizations have specific responsibilities for the system and field operations, maintenance, reliability, automation, and modernization of DTE’s distribution and subtransmission systems. We next review the responsibility alignments and staffing levels and changes since 2019 for the groups led by these Directors.

DTE’s Director of Engineering and Planning has responsibility for:

- Engineering standards
- Substation planning, engineering, and design
- Distribution and subtransmission engineering
- Substation, relay, and control engineering
- Reliability engineering
- Equipment engineering
- Inspection and proactive maintenance program management
- Reliability program management
- Distribution automation engineering, operations, and support.

The next table shows DTE Engineering and Planning full time equivalent (“FTE”) levels by year for the past three years. Those levels have declined substantially, by approximately 20 percent, caused by the movement of Power Equipment Relay Test (“PERT”) and Primary Services Group personnel to the Substation group in 2022.

Engineering and Planning FTEs

Group	2019	2020	2021	2022	2023
Engineering	170	180	198	174	174
PERT	58	54	65		
Primary Services	21	21	15		
Total	249	255	278	174	174

DTE’s Director of Long Term Strategy has responsibility for managing activities necessary for capital program planning and budgeting and for the management of reliability programs. At the regional level, DTE employs three Directors of Regional Customer Operations (“RCOs”) with one responsible for two of the four regions. Their responsibilities include distribution system planning for the region(s) to which they are assigned and the 13 service centers within those regions and:

- Overhead and Underground equipment maintenance programs
- Distribution field operations
- AMI field operations
- Field collections and turn on and off
- Distribution safety and training.

The next table shows changes in RCO FTE levels since 2019.

Regional Customer Operations FTEs

RCO	2019	2020	2021	2022	2023
NE	280	285	274	272	325
NW	264	273	277	298	254
SE	481	467	441	469	472
SW	280	321	321	294	283
Total	1,305	1,346	1,313	1,333	1,334

The Director of System Operations (“SOC”) has responsibility for:

- Reactive maintenance
- Distribution system operations
- Distribution system operations engineering and support
- Outage management system planning, operations, and support
- Distribution automation engineering, operations, and support.

SOC FTE levels have remained stable since 2019, with the exception of a temporary increase in 2022, which corresponded with significant development work described in more detail later in this chapter and in the next. For example, DTE opened its new Electric System Operations Center (“eSOC”) in 2022 and began to operate the Outage Management System (“OMS”) and Distribution Management System (“DMS”) components of Advanced Distribution Management System (“ADMS”) in February 2023.

System Operations Center FTEs

2019	2020	2021	2022	2023
154	153	152	170	157

The Director of Storm Emergency Planning and Restoration (“EP&R”) has responsibility for:

- Emergency preparedness, planning, and emergency response plan maintenance
- Emergency response safety and training of ICS rules and responsibilities.

The next table shows that assignment of staffing specifically to EP&R began in 2022.

Storm Emergency Planning & Restoration FTEs

2019	2020	2021	2022	2023
-	-	-	19	30

The two Directors responsible for Distribution Operations Scheduling and Tree Trim have responsibility for:

- Operations and maintenance planning
- Vegetation program management
- Vegetation management field operations

- Vegetation management contractor management.

The next table shows Scheduling and Tree Trim staffing changes since 2019. Scheduling staffing declined by 94 FTEs across this period (42 percent) while Tree Trim FTE declined by 11 FTEs (11 percent).

Scheduling Organization FTEs

Item	2019	2020	2021	2022	2023
Scheduling	226	224	260	174	132
Tree Trim	46	35	33	41	35

The significant drop in Scheduling resources corresponds with the Project Management organization’s (“PMO”) staffing buildup in 2022. Recognizing the increasing investment levels to date and planned, DTE recently merged its Major Enterprise Projects and Distribution Operations Projects teams, forming the Project Management Organization described earlier in this chapter. This team has responsibility for execution of strategic investment programs including subtransmission system rebuilds, Pole and Pole-Top Maintenance and Modernization Program (“PTMM”), and 4.8kv hardening, for example. DTE plans for this group to support growing levels of project work, including planning, coordination functions, controls, and standard for growing project work levels. The next table shows the staffing of the consolidation PMO.

Project Management FTEs

2019	2020	2021	2022	2023
-	-	-	163	168

Much of the internal work for tree trimming involves oversight and supervision of contractor performance and costs. The increased numbers in internal Tree Trim resources correspond to a very large increase in contractor Tree Trim work in 2022 as explained in Section C.1.b of this chapter. The variation in internal Tree Trim resources appears to be related to the surge that began in 2018 to reduce vegetation cycles.

The Director of Substations has responsibility for:

- Distribution substation field operations and maintenance
- Substation, relay, and control field operations technicians
- Primary Services field representatives and engineers.

The next table shows Substation staffing level changes since 2019. FTE numbers have increased by 20 percent. As noted above, the movement of PERT and Primary Services Group FTEs drove a portion of this increase.

Substations FTEs

Group	2019	2020	2021	2022	2023
Substation	355	339	334	333	337
PERT				68	68
Primary Services				20	20
Total	355	339	334	421	425

The Director of ADMS (“Advanced Distribution Management System”) and Operating Technology (“OT”) Strategy has responsibility for:

- Meter and automated meter engineering, operations, and support
- Substation field contractor management.

We address later in this chapter and in the next the importance of ADMS to integrating systems that provide information regarding and control the operation of the distribution system. OT, like its companion IT, focuses on systems, platforms, and applications that play increasingly broad and critical roles in utility operations. IT focuses more on what is often termed an organization’s “front-end” activities for managing and making data available to users electronically; *e.g.*, information processing, networking, and cloud systems. By contrast, OT, sometimes referred to as serving the “back end” of an enterprise’s operations, focuses on capabilities that enable communication with machines and equipment to keep them operating on a controlled and coordinated basis.

The next table shows ADMS and OT Strategy FTE level changes since 2019.

ADMS and OT Strategy FTEs

2019	2020	2021	2022	2023
75	73	104	86	98

Five Directors of Projects and Automation have responsibility for capital project management, inspection and proactive maintenance, and engineering operations and support for distribution automation. The next table shows their staffing.

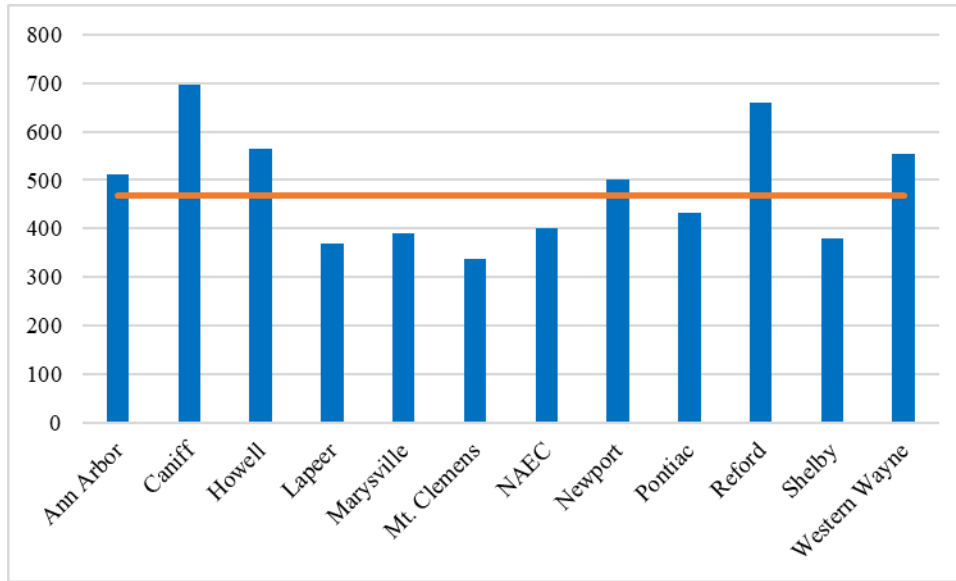
Projects and Automation FTEs

Organization	2022	2023
DO PMO	53	56
DO Logistics	47	58
Contractors-PMO	110	110
Contractors-Logistics	1	10

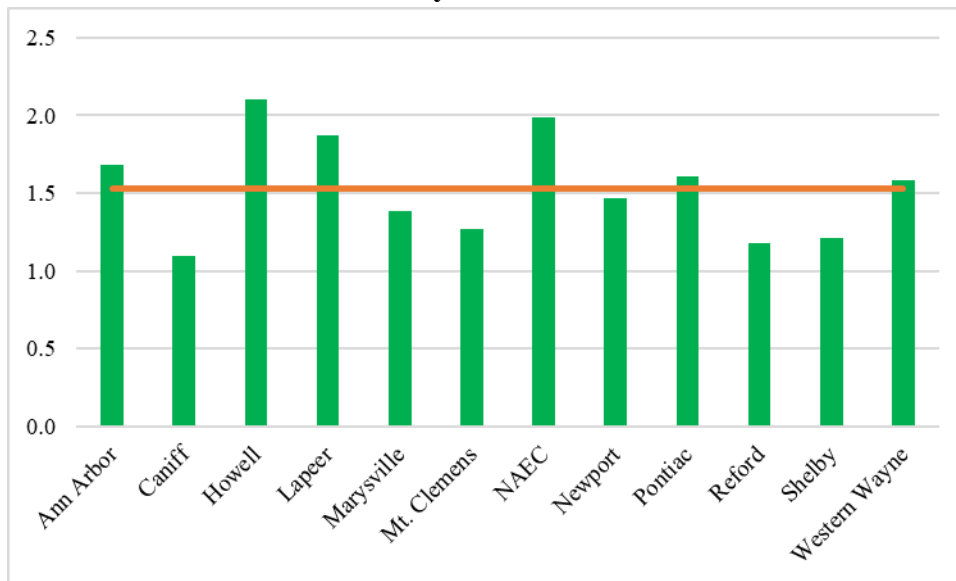
b. Outage Variations Across the System

The next tables show wide variation in outage durations as measured by the widely used CAIDI, SAIFI, and SAIDI. The tables show these index values including MEDs. Each chart shows the five-year average value for each of DTE’s service centers, and the median value.

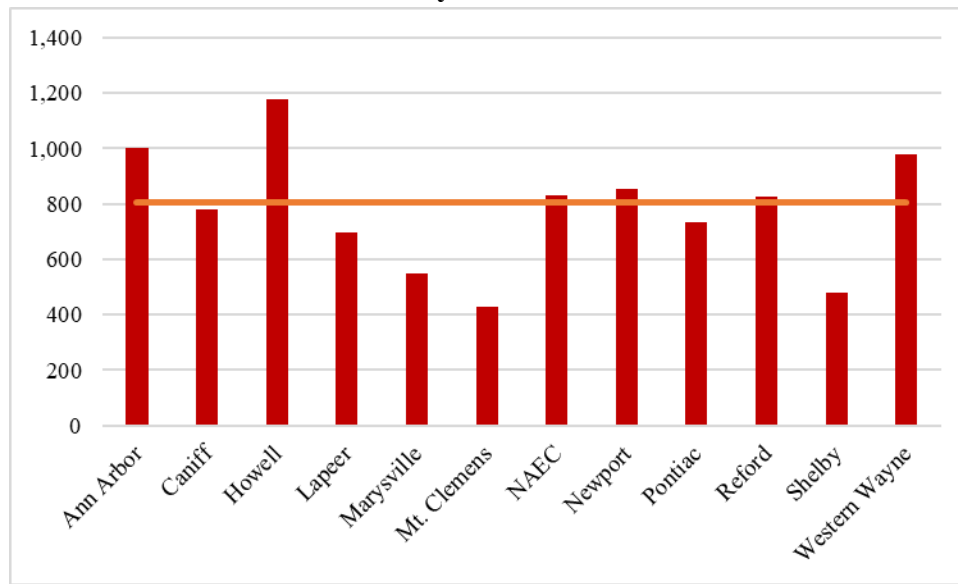
CAIDI by Service Center



SAIFI By Service Center



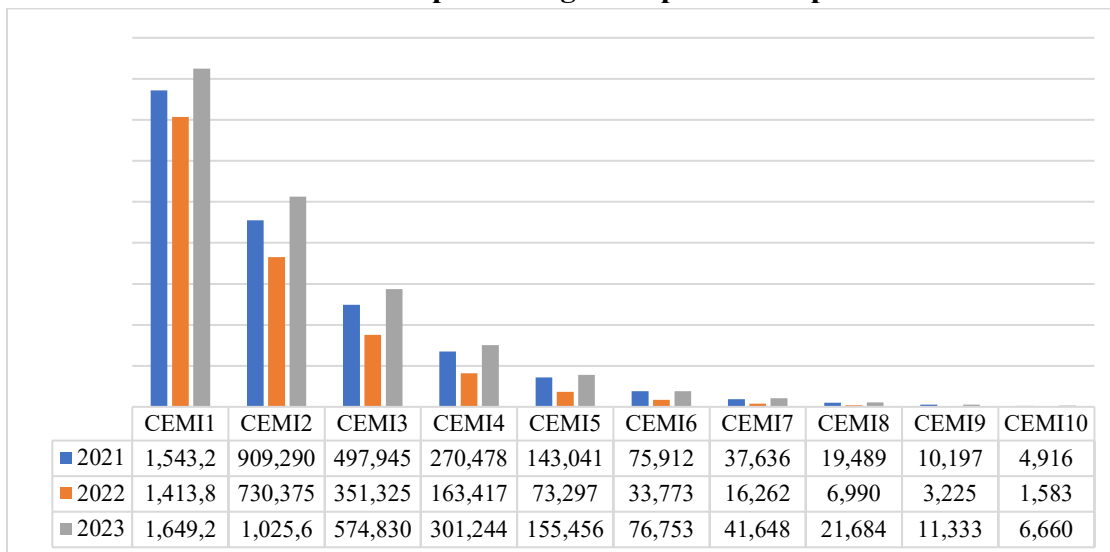
SAIDI By Service Center



Several factors contribute to the variation in these all-weather measures across the service centers, including storm paths, the timing of tree trimming, the condition of electric infrastructure, and the availability of resources for restoring service during multiple outages. Nevertheless, the variations are significant.

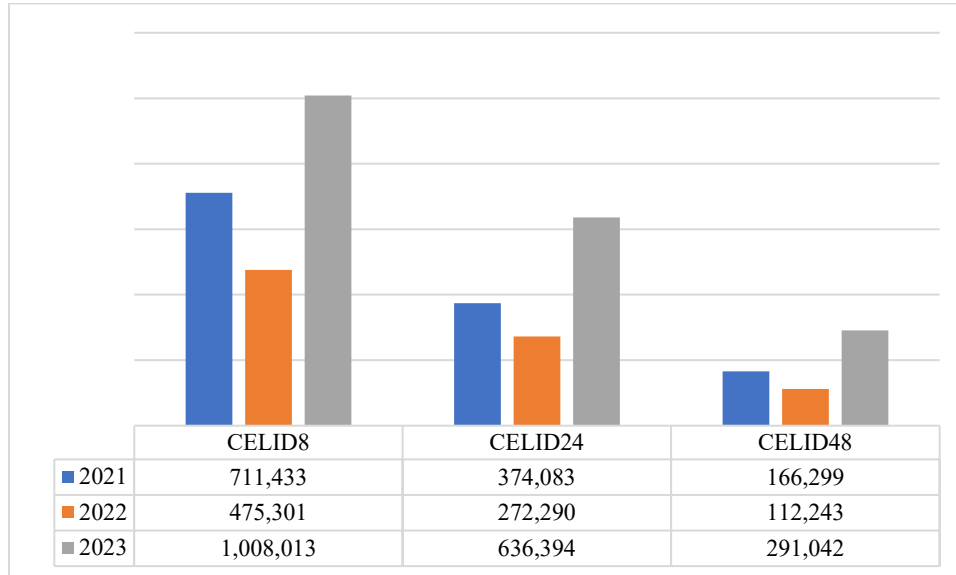
The next chart shows the numbers of DTE customers experiencing multiple interruptions, measured by the widely used Customers Experiencing Multiple Interruptions (“CEMI”). The digit following CEMI in the chart indicates the number of interruptions. The chart shows high numbers experiencing four or more interruptions during a year.

Customers Experiencing Multiple Interruptions



The numbers of customers experiencing long interruptions is also high. The next table shows those numbers, under the widely-used Customers Experiencing Long Interruption Durations (“CELID”). The number following CELID provides interruption length in hours.

Customers Experiencing Long-Duration Interruptions



c. Distribution Operations Labor O&M and CapEx History

This following table shows labor O&M spending from 2020 to 2023 excluding overhead costs, by distribution operations organization. It shows straight time labor (“ST”) and overtime labor (“OT”). The table shows that:

- Regional Customer Organization and tree trimming (except 2022) annual labor O&M costs have been stable
- Substation, engineering, and system operations labor costs have fallen
- Storm contractor costs surged in 2023 due to the ice storm
- In 2023, 76 percent of O&M was for Storm Contractors and Tree Trim Contractors.

Labor O&M Spending History

Type	2020	2021	2022	2023
RCO Labor ST	\$30.7	\$27.0	\$29.3	\$28.3
RCO Labor OT	\$6.3	\$8.4	\$8.9	\$8.0
Lines Contract Labor	\$8.0	\$10.5	\$23.1	\$10.9
Substation ST	\$15.9	\$13.7	\$15.4	\$13.6
Substation OT	\$2.5	\$2.1	\$2.2	\$1.4
Substation Contractors	\$1.7	\$2.4	\$3.3	\$1.8
Engineering ST	\$8.7	\$8.2	\$9.4	\$8.2
Engineering OT	\$0.4	\$0.4	\$0.3	\$0.4
Engineering Contractors	\$1.7	\$1.2	\$1.8	\$0.7
System Operations ST	\$7.9	\$6.0	\$6.2	\$5.7
System Operations OT	\$3.1	\$1.3	\$1.1	\$0.9
Storm ST	\$6.4	\$11.7	\$5.4	\$9.1
Storm OT	\$6.7	\$10.2	\$6.3	\$6.7
Storm Contractors	\$27.0	\$49.7	\$44.2	\$153.6
Tree Trim ST	\$2.9	\$3.1	\$3.1	\$3.2
Tree trim OT	\$0.9	\$1.3	\$1.6	\$1.4
Tree Trim Contractors	\$172.0	\$174.0	\$244.0	\$169.0

millions of dollars

The following table shows O&M labor costs for non-storm blue sky emergent trouble.

Emergent O&M Costs (in millions)

Asset	2019	2020	2021	2022	2023
Overhead	\$18.2	\$19.5	\$20.4	\$28.2	\$30.2
Underground	\$8.4	\$9.3	\$9.0	\$12.3	\$3.7
Substation	\$16.4	\$12.6	\$12.9	\$14.3	\$11.0

This table illustrates labor costs charged to capital expense (“CapEx”) from 2020 to 2023 by capital project program type. The CapEx values for the last three months of 2023 are estimated and do not include overhead costs. It shows that:

- Emergent CapEx was 43 percent of the total CapEx in 2023. Emergent spending has historically proven the greatest source of capital, but has fallen since 2021
- Historical infrastructure redesign, resilience, hardening, and automation investments have increased since 2020 and experienced a significant spike in 2022.

The next chapter of this report shows significant further capital spending above 2023 levels through 2028 under DTE’s 2023 DTE DGP.

Labor CapEx Spending

Source	2020	2021	2022	2023
Customer Connections & Relocations	\$135.6	\$150.5	\$174.0	\$106.9
Infrastructure Redesign	\$19.1	\$37.8	\$110.9	\$69.4
Infrastructure Resilience & Hardening	\$117.6	\$129.6	\$288.2	\$173.3
Tech & Automation	\$6.9	\$29.5	\$49.4	\$38.8
<i>Subtotal</i>	<i>\$279.2</i>	<i>\$347.4</i>	<i>\$622.5</i>	<i>\$388.4</i>
Emergent	\$250.9	\$490.6	\$310.2	\$293.4
Total	\$530.1	\$838.0	\$932.7	\$681.8

millions of dollars

This table illustrates a breakdown of the CapEx labor investments, excluding overhead costs, for 2020 to 2023. This chart shows that:

- For emergent work, FTE overtime costs were near straight time spending and contractor costs were greater than FTE costs.
- For planned work, contractor costs were much greater than FTE costs.

Labor CapEx Breakdown

Source	2020				2021				2022				2023			
	ST	OT	OT%	Contractor	ST	OT	OT%	Contractor	ST	OT	OT%	Contractor	ST	OT	OT%	Contractor
Customer Connections & Relocations	\$57.7	\$13.6	24%	\$64.3	\$58.5	\$16.5	28%	\$75.5	\$52.2	\$16.5	32%	\$105.3	\$29.4	\$8.8	30%	\$68.7
Infrastructure Redesign	\$7.5	\$1.2	16%	\$10.4	\$12.9	\$1.9	15%	\$23.0	\$24.4	\$3.3	14%	\$83.2	\$16.9	\$4.8	28%	\$47.7
Infrastructure Resilience & Hardening	\$28.3	\$5.9	21%	\$83.4	\$26.4	\$6.8	26%	\$96.4	\$27.3	\$9.2	34%	\$251.7	\$19.6	\$6.8	35%	\$146.9
Tech & Automation	\$1.9	\$0.2	11%	\$4.8	\$8.5	\$0.4	5%	\$20.6	\$8.6	\$0.3	3%	\$40.5	\$8.4	\$0.3	4%	\$30.1
<i>Subtotal</i>	<i>\$95.4</i>	<i>\$20.9</i>	<i>22%</i>	<i>\$162.9</i>	<i>\$106.3</i>	<i>\$25.6</i>	<i>24%</i>	<i>\$215.5</i>	<i>\$112.5</i>	<i>\$29.3</i>	<i>26%</i>	<i>\$480.7</i>	<i>\$74.3</i>	<i>\$20.7</i>	<i>28%</i>	<i>\$293.4</i>
Emergent	\$76.1	\$71.0	93%	\$103.8	\$86.5	\$90.3	104%	\$313.8	\$83.8	\$86.1	103%	\$140.3	\$74.9	\$67.1	90%	\$151.4

millions of dollars

Section C of the following chapter addresses the high capital costs of DTE emergent work.

d. Promoting Best Practices

A utility should have formal processes to ensure that its practices and processes align with best practices, including training, skill building, knowledge transfer, and benchmarking. A DTE “Center of Excellence” program provides for the distribution operations organizations the sharing of best practices, skill development, consistency of processes, innovations, problem solving, benchmarking, and adapting industry trends and emerging technologies. These processes involve human resources, training, standards, operations and engineering, executive officer, supervisor, technician, and trainer personnel. The Center of Excellence processes has been in place for many years, except the Learning and Technical Development function was added in 2019.

DTE also employs Subject Matter Experts (“SMEs”) recognized as possessing expert knowledge about specific assets. These SME’s lead the Equipment Performance group. They analyze applications, performance, maintenance, and end of life for overhead, underground, substation, relay, and SCADA systems. They also serve as a source for transferring technical knowledge within the company.

2. Conclusions

2. Except for its asset management program, the structure that DTE has created under its Director-level managers is appropriate and appears to have responded to changing needs, particularly as they relate to the Company's substantial reliability program expansion to date and proposed by the DGP.

(Note: Section F of this chapter addresses asset management.)

DTE has logically organized functions and responsibilities and has shown a willingness to change resources as workloads have changed in size and shifted in required activities. Of particular note, the creation of a significant project management organization responds to sizeable increases in reliability programs underway and called for by the DGP. Similarly, added Substation resources reflect increased work levels there as well. Increases in ADMS/OT resources reflect increasing use of technology in the distribution system to date and planned. DTE has also increased EPR resources (addressed in Chapter Three of this report). Stability or moderate reductions in the remaining areas appear consistent with realignments of functions with new Director-level group creation and changing activity levels. To summarize changes since 2019:

- EPR FTEs that began at 19 in 2022 increased to 30 in 2023
- Substation FTEs increased from 356 in 2019 to 425 in 2023 (which includes the movement of PERT and Primary Service from Engineering to Substations)
- ADMS/OT FTEs increased from 75 in 2019 to 98 in 2023
- Project Management (organized in 2022) had 168 FTEs in 2023
- Numbers of FTEs in the four RCOs remained level from 2019 to 2023
- The number of Scheduling FTEs reduced from 41 in 2021 to 35 in 2023
- System Operations FTEs fell from 170 in 2022 to 157 in 2023.

We found that leadership in Central Engineering, Regional Distribution and Substation Planners and Engineers, the Field Operations, Project Management, Tree Trim, Long-Term Strategy, and System Operations works well together.

3. Growing use of contractors reflects the increased work levels of recent years, but along with steadily increasing overtime use, shows the strains that the greatly increased programs, measures, and activities will place on DTE's continuing ability to execute work efficiently. (See the Recommendations of the next chapter)

DTE, as is common, relies very substantially on contractors for performance of much of its capital work. In the short run, it is also common for work level increases, like DTE has experienced to be addressed through the use of overtime by inside resources and increases in contractor personnel. The data show both at DTE since 2020. However, DTE's 2023 DGP indicates not short term, but systemic, long term increases. The roughly one-to-one ratio between straight time and overtime for internal resources is not uncommon for emergent work, given the focus on restoring as many customers as quickly as possible. However, sustained overtime levels in excess of 15 percent raise questions of work efficiency, both in terms of dollars per hour of work and in the effectiveness of work performance. DTE has experienced levels above 20 percent and steadily rising since 2020.

DTE cannot effectively continue to perform expanding work in the future by continuing to increase overtime, or even to sustain it. Increased internal staffing and contractor use will clearly be required at very significant levels, even with significant reduction of annual 2023 DGP planned levels. As the next chapter describes, ensuring that DTE can acquire those resources and then further ensuring that its program and project management organizations grow and mature as the needs they must address do is essential to developing a realistic plan that can be achieved without degradation in work effectiveness, efficiency, and timeliness.

4. DTE appears to require significantly more engineering personnel. (See Recommendation #1)

Engineering and planning FTEs have fallen significantly, with 2023's count of 175 at only 70 percent of 2019 levels. Moreover, 2023 numbers were at half or less of budgeted levels. The very large reliability programs it will take to reach DTE's reliability targets appear to require significantly more engineering resources than exist now. The inability to provide them not only risks significant delay in program execution, but in effectiveness and efficiency if engineering and design do not produce necessary support to meet expectations that form the basis for committing field resources. Significant increases in Substation and ADMS/OT will play an important role, but as the large gap between budgeted and actual engineering positions shows an organization that, at the least, is in transition even as large DGP program increases loom.

5. DTE has adopted and executes sufficient means for promoting the use of best practices.

The Company's Center of Excellence appears to operate in a manner that broadly addresses improvements and innovations, considering trends and technological advances in the industry.

6. Regional variations in outage durations and comparatively large numbers of customers experiencing multiple and long duration averages per year warrant enhanced organizational focus on controlling them. (See Recommendation #2)

Programs exist for addressing outage durations and for those pockets of customers who experience more severe reliability outage frequency and duration impacts like those measured by CEMI and CELID. Management measures performance at the local level, but does not employ a central organization for closely tracking the areas of and reasons for areas or pockets with persistent, substantial outlying performance. Some organizations have employed a central source of data gathering, performance analysis, and even control over resource allocation among operating locations to ensure sufficient focus on minimizing variations among operating areas and on ensuring priority on CEMI and CELID problem pockets. Variation in CAIDI among field locations and the numbers of customers with particularly high CEMI (four interruptions per year) and CELID (durations of 24 hours or more) warrant DTE's attention.

3. Recommendations

1. Construct an intermediate and long-term engineering resource plan based on a range of expected work levels through and beyond 2028. (See Conclusion #4)

The DGP creates engineering resource planning challenges beyond those more typical of electricity distribution utilities. The plan calls for very large increases in work that will occur for the most part over five years, but must pass rate regulatory muster annually, adding risk to

extending employment (internal personnel) and contract (outside resources) commitments. Moreover, for work that will create a work expansion “bubble” optimizing the blend of internal and external resources becomes critical. The DGP describes large, but uncertain programs that have significantly longer durations (*e.g.*, completely eliminating the 4.8kV distribution facilities that comprise so large a part of DTE’s system).

DTE needs an engineering resource plan that takes account of the time and work level uncertainties it faces. This plan should account for a range that extends from little or no expansion from current work and program levels through to completion of a long and extraordinarily expensive process of converting essentially all 4.8kV circuits. It should identify incrementally how it can and should optimize internal/external resource balancing for a range of scenarios between the two if and as commitments to various program types and levels are enabled. The plan should not only address resources by roles, numbers, and relationships, but should also identify how the nature and timing of commitment enablement will affect the pace of major programs and in turn the securing and maintaining of resources to execute them timely, effectively, and efficiently as well.

2. Create a position dedicated to addressing the variation in outage durations across the service area and numbers of customers experiencing frequent multiple outages and those suffering particularly long outage durations. (See Conclusion #6)

There is attention to resources, programs, measures, and activities to address outage duration generally, long durations particularly, and to customers experiencing multiple interruptions. There is also measurement and reporting of the causes of such customer disruptions. However, no organization between vice presidential level and the director-level regional operations organizations focuses on these aspects of delivering reliable service.

Variation in outage levels by area and numbers of customers experiencing too many or too long interruptions call for creating a small group with that focus. It should not undercut the role of regionally organized resources for conducting required activities to address these areas timely, effectively, and efficiently. In terms of information, its role would be to ensure that information about reliability measures in these areas is routinely kept accurate and up to date, and to do the same for information about activities, resources, and methods used across the territory to influence that performance. In terms of analysis, this organization should ensure the application of methods and practices as designed and budgeted, identify any whose application to other regions could improve performance effectiveness or efficiency, and assess where altering the balance of resources among areas would better levelize performance, recognizing inherent differences that limit performance equalization.

D. Planning

1. Findings

The functions of electric utility planning and engineering organizations include monitoring and predicting system asset conditions, identifying where peak loads exceed or will exceed system component ratings and where reliability issues exist, and then to develop and prioritize best cost to benefit solutions.

DTE’s DGP proposes very large investments to address both capacity constraints and reliability and resiliency. The programs, projects, and activities driving improvements in these two areas require careful planning, coordination, assessment of the contribution that each makes in relation to capacity and to reliability and resiliency goals, particularly given the very short duration DTE has set for making very large improvements in the latter of these two areas. The pace of improvement needs to be carefully and continually assessed to ensure the ability to make inevitable adjustments as management assesses:

- Its ability to carry out greatly increased work levels timely, effectively, and efficiently
- How to rebalance programs, projects, and activities as it gains more insight into the effectiveness and individual contributions of all of them, particularly with respect to reliability and resiliency.

The DGP provides a baseline for proceeding, but DTE will need to continue to determine objectively and continually which programs, projects, and activities contribute most to tangible improvements for the least cost not only to date, but as can be expected going forward. Optimization requires confidence regarding the individual and incremental benefits that overlapping and mutually contributory programs and measures have on reliability results, soundly pacing new and expanded programs to gain information about benefits gained for dollars spent, and a clear understanding of potentially diminishing results as increasing penetration of measures across the system more and more picks the “low hanging fruit.” Prioritizing on the basis of worst performance, for example, can show impressive early results that prove misleading when advancing down a line of facilities having better baseline performance.

The director level Engineering and Planning organization has responsibility for planning to meet capacity and reliability needs. Regional Customer Operations (“RCO”) undertakes project planning for small projects and the Central Distribution or Substation Engineers located in the Central Headquarters plan for large projects. After authorization, the Project Management Organization, working with the Scheduling and Logistics (Contractors) Organizations, has responsibility for managing large capital programs and projects.

a. Capital Project Planning, Evaluation, and Approval

DTE uses its Global Prioritization Model (“GPM”) as the main tool in the prioritization of strategic capital programs and projects. Most capital improvement initiatives provide more than one reliability benefit, as well as other important benefits such as improved public safety, elimination of an overload situation, investment in an Environmental Justice (“EJ”) community, or a reduction in ongoing and repeat O&M costs. Overall, the GPM includes and evaluates ten different and important benefit areas when prioritizing investments. Each benefit area is called an “impact dimension” and each has one or more drivers which are measured to quantify a benefit.

Benefit Area List

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire down events	3
	• Reduction in secondary network cable manhole events	
Overload Relief	• Elimination of overloaded equipment	
SAIDI	• Reduction in duration of outage events	
SAIFI	• Reduction in frequency of outage events	
Regulatory Compliance	• MPSC staff’s recommendation (March 30, 2010 report) on utilities’ pole inspection program	2
	• Docket U-12270 – Service restoration under normal conditions within 8 hours	
	• Docket U-12270 – Service restoration under catastrophic conditions within 60 hours	
	• Docket U-12270 – Service restoration under all conditions within 36 hours	
	• Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
O&M Avoidance	• Trouble event reduction and truck roll reduction	1
	• Preventive maintenance investment reduction	
Capital Avoidance	• Trouble event reduction and truck roll reduction	
	• Reduction in capital replacement either during equipment failures or avoided planned capital work	

Projects and programs receive scores in each dimension (generally ranging from 0 to 100) based on the amount of expected benefit divided by the total investment (in most cases). This investment selection approach and structure seeks to evaluate programs and projects and prioritize the funding of investments that deliver the most effective system improvements and the broadest set of benefits to customers.

Projects that deliver more benefits per dollar invested receive higher scores in that dimension. The score in each dimension is multiplied by a weighting factor for that dimension. The weighting factors enhance the scores of projects that provide benefits in core reliability and safety. The dimension scores add together to provide a total project or program score. The projects and programs with higher scores provide more benefits and receive higher priority. The intended result is a portfolio which is optimized across all multiple benefit dimensions, where projects that deliver the most combined value in safety, reliability, and load relief improvements get executed first. DTE has employed evolving versions of this Global Prioritization Model (GPM) since 2018.

b. Addressing Capacity Needs

Capacity-related projects seek to prevent or relieve overloading system components caused by existing or forecast peak loads, and sometimes by specific load additions. Such “load relief” and “new business” projects include measures such as new or enhanced substations, transformer replacements, subtransmission rebuilds, and 4.8 kV substation and circuit rebuilds and

conversions. A number of DTE capital programs seek to harden or strengthen system components to maintain or enhance reliability in circumstances ranging from normal to extreme weather. DTE measures of this type include, for example, PTMM and 4.8 kV hardening, 4.8 kV substation and circuit conversions (which primarily serve capacity needs).

DTE’s load exceeding criteria, as required by its Distribution Design Orders (“DDOs”) guide the planning of capacity projects. When new business connections may threaten such overloads, RCO planners examine new business connection requests, engaging Central Distribution Engineers and Subtransmission Planning Engineers when initial review indicates potential loads large enough to require load studies to assess the capacity of the facilities involved to support the customer demands involved. Analysis of potential alternatives to system enhancement or reinforcement follows when these studies indicate system inability to handle increased loads at the levels expected. Capacity limits, which have become fairly common on portions of the DTE system, can also occur through more generalized growth not tied to specific large new business requests. DTE routinely assesses locations and likely levels of that growth, modeling the capability of the system to accommodate it and examining alternatives like reconfiguration, new or augmented facilities, and voltage conversions.

c. Addressing Reliability and Resiliency

Maintaining and improving reliability also drives planning, sometimes overlapping with addressing capacity-related needs. Projects focused on reliability and resiliency aim at reducing outage numbers, reducing the numbers of customers affected when outages occur, and reducing the duration of customer interruptions that follow outages.

Resulting reliability and related resiliency measures can, and at DTE are planned to involve a portfolio of capital programs and projects of potentially long duration and high cost. Reliability maintenance and improvement also depend significantly on O&M activities. Planning for resiliency and reliability projects considers the numbers of outages and the numbers of customers affected by outages localized to permit planners to associate these data with the particular facilities that affect them.

d. Changing Weather, Electrification, and Interconnection Impacts on Planning

DTE’s 2021 DGP addressed the implementation of scenario planning to assess possible effects on the grid from the rise in Electric Vehicle (“EV”) adoption, more frequent extreme weather events, and the evolving integration of Distributed Generation/Distributed Storage technologies (“DG/DS”). The 2023 DGP describes three scenarios driven by a range of assumptions about climate, EV, and distributed energy:

- Electrification Scenario
- Increasing Catastrophic Storm Scenario
- Distributed Generation/Distributed Storage Growth Scenario.

The Electrification Scenario mainly emphasizes the move to electric vehicles of all types and sizes. This scenario anticipates that efforts to decarbonize will generate a significant rise in residential EV penetration and a partial transition to electric vehicle fleets. These changes would produce higher demand for electricity on the distribution system. December 2022 estimates placed the number of EVs in DTE’s service territory at 31,000, with projections from the automotive industry

predicting a significant increase in EV sales in the near future. Cited assumptions include 50 percent of light-duty vehicle sales, 30 percent of medium- and heavy-duty sales and 100 percent of bus sales as electric by 2030.

Significant EV industry and marketing challenges will need to be overcome to support short- and long-run EV targets and the penetration rates needed to reach them. However, the challenge that electric utilities, DTE included, face is to be prepared to meet them if and as those challenges are met, while making the improvements in a way that avoids premature commitment of resources to a system already facing other needs that will drive electricity pricing. It will remain important for DTE's scenario development to consider a significant range of actual penetration and to incorporate the flexibility to respond as changes in the industry or its markets drive EV penetration in both directions. With government requirements and incentives playing so large a part in industry development and market conditions, fast response to changes that have significant investment consequences will remain important.

Already significantly stressed at the present time, these electrification assumptions would further reduce the ability of DTE's grid to respond to capacity needs. Increasingly heightened demand on substations and circuits would limit grid flexibility and resilience, making it difficult to shift loads among different areas during either normal operations or in emergencies. More extreme demand increases would also increase risk of faster equipment aging and more frequent failures, as resources not reinforced fast enough become required to deal with loads ever further above their operating and emergency ratings.

The Increasing Catastrophic Storm Scenario focuses on climate change causing a rise in both the frequency and intensity of extreme weather events in the upper Midwest, including Michigan. The DGP addresses the risk to the Company's infrastructure stemming from weather shifts. Despite large uncertainties in projecting catastrophic weather events due to limitations in existing weather models and missing or inaccurate historical data, the scenario anticipates "a future where severe weather events increase in intensity" and where the numbers of customers affected grow. DTE observes that its already aged equipment and already significant distribution system capacity limitations will make it increasingly susceptible to the effects of severe weather as time passes. The Increasing Catastrophic Storm Scenario pointedly reinforces the need for DTE to identify programs, projects, and initiatives whose expansion can accommodate that scenario if significant weather worsening comes to challenge the assumptions driving Company plans.

The Distributed Generation/Distributed Storage ("DG/DS") scenario focuses on the ongoing penetration of distributed generation and storage technologies in DTE's service territory, lowering electricity demand for some customers providing for the export of power back to the distribution system. The scenario anticipates that technical advances and lowering costs of wind, solar and other generation and energy storage technologies will catalyze customer installations. DTE also cites as a factor ongoing Midcontinent Independent System Operator ("MISO") implementation of FERC Orders 841 and 2222, which, when implemented can provide residential as well as commercial and industrial customers opportunities to participate in the wholesale market. DTE reports that incorporating Distributed Energy Resources ("DERs") into the distribution system could offer several advantages, including decreased distribution system losses and alleviation of some local overload issues. However, there can be negative implications for the distribution system

and its operation as well. Significant levels of DERs can lead to localized challenges within the grid, such as voltage and thermal problems that affect power quality, as well as problems affecting the coordination of fuses, distribution automation, and other protective devices. As more customers adopt these resources, the DTE plans to continue the analysis of the effects of DER, both positive and negative.

e. Service Equity

DTE is incorporating addressing environmental justice (EJ) areas of its system in its Global Prioritizing Model. EJ vulnerable areas include approximately 20 percent of the distribution circuit mileage and 550,000 customers. Over the last few years EJ SAIFI has been better than the system SAIFI, and for most of the years the EJ SAIDI has been better than system SAIDI. The Company has made increasing investment in vulnerable areas: sixty-four percent of the 4.8 kV conversions; *e.g.*, 85 percent of the 4.8 kV hardening, and 25 percent of the tree trimming investments since 2018. These percentages are greater for proposed investments in 2024 and 2025. These measures have direct bearing on reliability measures.

Following DTE's filing of its 2021 DGP, the State of Michigan introduced the MiEJScreen tool, which the Company now uses to identify at-risk communities among its customer base. DTE classifies vulnerable communities as those with a composite MiEJScreen score at or above the 80th percentile. The 483 census tracts in the Company's service area that fit this criterion include 550,000 customers, or about 25 percent of total DTE residential customers. DTE has mapped its reliability and investment initiatives in relation to the locations of these customers. The following map shows with green highlighting customers in first quartile (*i.e.*, best reliability measured by all-weather SAIDI minutes) and with red highlighting those in the fourth quartile (worst reliability) tracts.

2022 All Weather SAIDI by Census Tracts with 80 to 100% MiEJ Score



Analysis by DTE has led the Company to conclude that investments, particularly in the City of Detroit, have led to enhanced reliability for at-risk customers. DTE’s aging 4.8kV distribution system serves a large majority of the 483 MiEJScreen at-risk tracts, particularly in the city of Detroit. DTE’s significant investment in 4.8kV Conversion and the 4.8kV Hardening programs thus will prove particularly beneficial customers in these tracts, as the next table summarizes.

Investments in Census Tracts with 80 to 100% MiEJ Score

Investment Program	% Of Investment in Vulnerable Communities	
	(2018 – 2022)	(2023-2026)
Conversion	75%	86%
4.8kV Hardening	89%	93%
Tree Trim	30%	14% ⁵²

The DGP explains three Environmental Justice-focused objectives incorporated into DTE's distribution planning process going forward:

- ***Update Global Prioritization Model:*** integrates into the revised GPM model a factor that prioritizes projects for vulnerable communities over others with comparable scores
- ***Improve System Performance:*** pinpoints 191 at-risk community circuits that rank in the lowest reliability performance quartile, one third of them already improved and the remainder specifically to be included in DGP investment programs
- ***Outage Response:*** measures include van delivery of essential supplies, support for warming and cooling centers, safety checks for senior customers, and communications with customers and community leaders during storm events.

In summary, there is evidence that DTE has made strides in incorporating Environmental Justice into its distribution planning processes and intends to continue enhancing these efforts over time. Additionally, the Company's ongoing plans to significantly invest in the hardening and the replacement of aging 4.8kV infrastructure, while not specifically targeted to Detroit's most vulnerable communities, will benefit electric reliability of those communities.

f. Project Review and Approval

We found fairly typical guidelines and processes for identifying, examining, and comparing alternative solutions for addressing problem areas or circumstances. Projects over a set value threshold undergo a Project Value Analysis, securing peer group review by engineering, operations, construction, and project management organization members. This review compares a proposed solution with identified needs to alternative solutions. The Engineering Leadership team reviews recommended solutions. Upon approval, planning engineers working with the Project Management team to establish project material, personnel, and other requirements and set schedules for execution.

As they exceed estimated cost thresholds, projects undergo schedule, plan, and budget review by a Project Governance Review Board, and require CFO and COO approval. The Project Management Organization works with the Logistics Organization to create resource forecasts and to align contractor resources as needed for the projects.

g. Municipal Coordination

The Company reports that its policy is to meet with representatives of affected localities to discuss project benefits and details. DTE also reported that its policy includes consideration of work coordination opportunities before requesting permits. DTE also reports that its policy is to provide periodic updates and opportunities for raising questions and concerns as work progresses.

DTE has reported recent opportunities for joint or collaborative work, citing the city of Ann Arbor with respect to coordinating on its electric and gas work city projects in overlapping areas. DTE also reported efforts to coordinate a conduit replacement project at Southfield with the Oakland County Road Commission's planned road resurfacing. DTE also cited its efforts to coordinate its undergrounding electric and gas improvement work with planned work by the Detroit Water and

Sewage department and Public Lighting Authority. DTE has also cited work with the Detroit Land Bank to obtain easements on its property.

We did not examine activities to execute these policies, or the results of the cited examples.

h. Failure Analysis

Identifying the root causes of equipment failures and operational errors contributes significantly to the identification of needed changes in equipment choices, configurations, maintenance practices, and contribution of operational error. A comprehensive and effectively executed practice for analyzing failures and operational errors comprises an important element of planning to prevent or mitigating the impacts of systemic outage and safety risks, to protect equipment in order to avoid costly replacements and repairs, and to identify needed changes in equipment types, classes, or providers for particular applications.

Management investigates the causes of outages of events that exceed certain thresholds, *e.g.*, outages of 200 or more customers for eight hours or more, interruption of 5,000 or more customers regardless of duration, and all substation de-energizations. For equipment caused outages, DTE retains the failed artifacts for investigation and examination, engaging engineers and technicians as required to apply expert insights applicable to the type of equipment involved. Equipment Specialists in the Engineering organization conduct a formal root cause analysis in cases where early examination cannot explain the cause of a failure or where there exists a risk of repeat failures across the system; *e.g.*, faulted cable and a substation transformer or circuit breaker.

Management factors the results of root cause analysis (where warranted) into asset health scoring for similar equipment. Identification of operational error as a potential contributing cause leads to the conduct of an Anatomy of an Event Investigation. DTE operates a hazardous energy control program that seeks to eliminate employee injury risk during equipment service or maintenance. Field operational errors or violations identified may generate the issuance of a report to the Hazardous Energy Control Committee for consideration. System Operations operator errors identified produce a human performance document and retraining as required.

Management engages expertise as required to support these processes. Those sources include the Warren Service Center metallurgy lab, vendors, EPRI, NEETRAC, and peer utilities. NEETRAC (the National Electric Energy Testing, Research & Applications Center) operating under Georgia Tech University guidance, includes as members utilities serving nearly two thirds of U.S. electricity customers. NEETRAC provides research and testing services for utilities and manufacturers.

2. Conclusions

7. We found DTE’s modeling used for evaluating, comparing, and prioritizing reliability initiatives, sound.

DTE’s Global Prioritization model, which systematically compares and evaluates competing system improvement and reliability-enhancing projects and programs across 10 important improvement dimensions, seems a balanced and logical application of the “best fit, most

reasonable cost” economic approach to investment optimization. Its application at DTE is consistent with other utility strategic investment good practices that Liberty has experienced.

8. DTE employs a sound organization to conduct distribution system planning.

System planning falls under the Director of Engineering, with some groups located at Central Headquarters and others with more local responsibilities resident in regions that their work addresses. The division of responsibilities ensures focus on systems and issues of broader consequence, while keeping those responsible for particular areas co-located with other regional resources and close to the areas for which they are responsible. Planners and engineers work together to ensure that electric system conditions are understood and addressed.

9. We found planning methods comprehensive and effective.

Methods for forecasting peak loads, identifying reliability issues and system component overloading conditions, and for developing solutions, for conducting peer and management reviews, for authorizing, for scheduling, and for project management are consistent with the needs of the electric system and good utility practice. DTE coordinates its plans with those of public authorities whose own infrastructure needs involve common locations and address synergies that its own electrical and gas infrastructure work present.

10. The load forecasting and load modeling processes appear adequate for capacity needs currently identified, and operate under a range of future weather- and electrification-driven scenarios that entail significant uncertainty. (See Recommendation #3)

The data assembled for planning purposes shows increasing weather risk over time. Large variability in weather makes prediction over periods with durations like those of the DTE DGP uncertain, but we found sound the scenarios considered. Development of electrification scenarios responds to state decarbonization objectives, as it must. At present there is significant uncertainty over issues such as the likely growth in penetration of electric vehicles or the degree to which emphasis on decarbonization will influence the availability and price of energy sources other than electricity for customer use. DTE’s development and use of scenarios needs to continually address how changes in such factors affect the need for and timing of the large body of investments that its DGP plans.

The Company’s use of scenarios seeks to preserve its ability to respond timely. Nevertheless, it remains important to match the pace of expenditures with actual changes in electricity demand sources and weather. Data that becomes available over the course of the years the DGP covers may not much influence weather expectations for the planning horizon. Nevertheless, DTE needs to continually re-examine and at least annually reconfirm or adjust, as may prove necessary, the pace of programs, in consideration of the benefits that reducing the impacts of very large DGP period investments would have on electricity prices. While it appears less likely as of the time of this report’s completion, DTE needs to remain aware of data that may accelerate the impact of electrification on capacity-related investments as well.

11. DTE has undertaken steps to identify the intersection between environmental justice communities and its electrical facilities, and has identified and directed DGP measures to those communities, including a number that target circuits with low reliability.

The relative newness of Commission directives and DTE responses to them underscore a need for continuing stakeholder dialogue to assess the sufficiency of the investment natures and levels. For the present, we believe that the Company has shown:

- Willingness to engage in defining the intersection between its distribution system configurations and environmental justice communities
- The capability to design and take measures needed to assess equity in service provision
- Target investments to affected communities and particularly to portions ranking low in service reliability.

From the perspective of assessing practices and methods as we were engaged to do, these are material factors. It appears that the stakeholders and Commission have continued to engage in refining understanding of particular community service needs, expectations, and consequences of system upset conditions, all necessary to define what equity requires at an executable level. DTE has shown the capability to respond timely, adequately, and measurably, as those requirements evolve.

12. DTE employs sound measures for examining the causes of equipment failure and investigating operator error.

DTE applies appropriate methods for retaining failed equipment, investigating and conducting root cause analysis of equipment failures, and taking actions to prevent repeat failures. A formal program exists for investigating operator error and for taking actions to prevent recurrence of errors found. The Company engages sufficient outside expertise to inform its assessments and investigations.

3. Recommendations

3. Coordinate the pace of capital program execution with continually updated electrification scenarios. (See Conclusion #10)

DTE recognizes the planning challenges related to weather, in relation to outages during extreme conditions and to events or increased demand due to electrification and warming temperatures in cooling seasons. These evolving factors require modifications to grid modeling methods, and work is underway to address these needs. The cycles between DGP revision invite revision of scenarios on the basis of enhanced methods and changes in data about load influencing customer uses of electricity. Between those revisions, however, it remains important in optimizing capital resources for DTE to remain current with and promptly analyze policy changes and market developments that may drive changes in assumptions that can affect the need for the significant investment levels at issue here.

E. Infrastructure Program Management and Expenditures

1. Findings

High value capital infrastructure projects are necessary for improving component capacity and reliability and should be managed by a project management organization that takes full responsibility for managing the projects from planning to completion and ensuring that the project costs are optimized, and project completions are timely and verified as designed.

a. Project Management

Central Planning and Engineering develops and monitors CapEx Infrastructure Redesign, Resilience and Hardening, and Technology and Automation programs managed by the Project Management Organization, using contractors managed by the Logistics organization. The Infrastructure Redesign and Modernization program includes long-term programs to upgrade the distribution and subtransmission systems, and substations. The Infrastructure Resilience and Hardening programs are generally near-term programs to harden the system for severe storms. DTE intends Technology and Automation programs to improve reliability by providing better grid monitoring and control, and automatic sectionalizing. For quality control, the Company has an inspection team that inspects capital work within 30 days of completion. Vendors are expected to correct errors within five days of the inspections. In 2019, the Company began managing contractors under a Logistics Manager who manages two groups, one for overhead and one for underground capital projects. The overhead general supervisor manages three regional supervisors and facilitators located in the service centers. The underground general supervisor manages two supervisors located in the regions, and underground technicians located in the regions.

b. Infrastructure Expenditures

The following tables indicate the expenditures for the programs in each category each year from 2019 to 2023.

Infrastructure Redesign and Modernization Expenditures

Item	2019	2020	2021	2022	2023
4.8 kV Conversion	\$6.6	\$3.4	\$12.2	\$53.8	\$70.2
8.3 kV Conversion	\$0.2	\$0.5	\$0.9	\$4.2	\$16.1
CODI Conversion	\$10.1	\$18.4	\$25.7	\$48.5	\$101.4
Subtransmission	\$1.4	\$6.0	\$19.6	\$40.7	\$63.4
System Loading	\$1.5	\$5.6	\$4.0	\$3.6	\$18.3
Station Upgrade			\$3.6	\$14.7	\$24.6
Transformer High Side				\$1.9	

millions of dollars

Infrastructure Resilience & Hardening Expenditures

Item	2019	2020	2021	2022	2023
4.8 kV Hardening	\$48.5	\$57.4	\$66.7	\$161.4	\$86.0
4.8 kV Relay Improvement	\$1.8	\$2.1	\$3.2	\$5.0	\$0.0
PTMM	\$27.4	\$34.9	\$31.6	\$83.5	\$67.4
CEMI	\$21.5	\$34.9	\$31.6	\$83.5	\$67.4
System Res-Efficient	\$6.3	\$1.8			
URD Cable Replacement	\$3.5	\$1.0	\$4.7	\$7.0	\$15.6
Breaker Replacement	\$9.1	\$10.9	\$17.4	\$14.4	\$15.0
Cable Replacement	\$10.9	\$12.2	\$14.1	\$28.9	\$29.4
Porcelain Cutout Replacement	\$4.8	\$1.8	\$0.1	\$0.4	\$0.5
Disconnect Replacement	\$1.6	\$2.1	\$3.9	\$4.2	\$9.1
Mobile Fleet Program	\$2.1	\$2.4	\$6.0	\$15.2	\$5.2
Relay Replacement	\$2.7	\$2.7			
Pontiac Vaults	\$9.0	\$4.9	\$3.0	\$1.3	\$0.8
Highway Crossing				\$1.9	\$2.0
PTD Replacements					\$1.7
Regulator Replacements				\$1.7	\$1.3
Batteries/Chargers					\$2.9
Strategic UG Pilot				\$0.5	\$4.6
Substations	\$5.4	\$5.3	\$9.0	\$9.8	\$32.0

millions of dollars

Technology and Automation Expenditures

Item	2019	2020	2021	2022	2023
Line Sensors	\$5.0	\$2.5	-	-	-
AMI	\$31.9	\$8.0	\$1.5	-	-
Pilots	\$3.0	\$3.2	\$8.5	\$2.1	\$10.9
Distribution Planning Process Capability	-	-	-	\$21.7	\$17.6
13.2 kV Telecom	\$1.2	\$0.8	-	-	-
40 kV Subtransmission Switch Replacement	\$0.8	\$0.8	\$1.3	\$4.4	\$6.3
Analog Lines Elimination	\$0.4	-	-	-	-
Engineering Technology	-	-	\$3.0	\$0.6	-
Operations Technology	-	-	\$13.0	\$0.6	-
Telecom & Automation	-	-	\$18.4	\$22.9	-
Distribution Automation	-	-	-	\$0.5	\$20.5
Modernize Grid Management				\$12.0	\$24.9
Grid Automation				\$14.3	\$20.1
Asset Management				\$1.7	\$2.8

NWA				\$8.6	
Delta Ground					\$10.4
Substations Cyber Security					\$1.2
Other					\$14.4
Sensing					\$1.8

millions of dollars

c. *Outage Reduction by Reliability Infrastructure Programs*

This following table provides the Company’s estimated reduction in outages by the PTMM, 4.8kV Hardening, 4.8 kV conversion programs, and the reduction of the size of outages by the automation programs.

Estimated Outage Reductions

Year	Tree Trimming	PTMM	4.8kV Hardening	Circuit Conversion	Automation (Start of circuit) ¹	Automation (Loop scheme) ¹
	Event Reductions				Size of Outage Reductions	
N+1	-40%	-30%	-80%	-90%	-26%	-42%
N+2	-30%	-26%	-75%	-90%	-26%	-42%
N+3	-25%	-22%	-70%	-90%	-26%	-42%
N+4	-8%	-18%	-65%	-90%	-26%	-42%
N+5	0%	-14%	-60%	-90%	-26%	-42%
N+6		-6%	-55%	-90%	-26%	-42%
N+7		-2%	-50%	-90%	-26%	-42%
N+8		0%	-45%	-90%	-26%	-42%
N+9			-40%	-90%	-26%	-42%
N+10			-35%	-90%	-26%	-42%

2. *Conclusions*

13. DTE’s expenditures for infrastructure capital expenditures and O&M for tree trimming have, to date, been reasonable and the spending will provide SAIDI reduction over time.

3. *Recommendations*

We have no recommendations regarding Infrastructure Program Management and Expenditures. However, the next chapter provides our assessment of DGP reliability program expenditures.

F. Asset Management

1. *Findings*

The asset management function requires it to systematically, in the most cost-effective manner, track assets and asset conditions, maintain assets, upgrade assets, and if necessary, replace assets based on asset maintenance costs, asset failure risks and consequences of failure, and asset performance. Asset Management also includes specifying new and modernized assets and directing the asset inspection, maintenance, retirement, and failure analysis criteria. Electric

utilities usually have an Asset Management organization led by a director focused on managing assets using software applications to assist with the functions required for all electric system assets. Major assets are of high value and may cause high numbers of outages when they fail.

a. Asset Management Organization

Asset Management is one of the responsibilities of the Director of Engineering. The Engineering organization in the Central Headquarters includes 30 or more engineers, including the Equipment Performance group made up of equipment specialists who monitor the condition of 20 asset classes based on inspection and maintenance results, manufacturer and industry data, and asset performance. Using Maximo software to track asset health, they determine the inspection and maintenance practices and cycles for each asset and determine when special off-cycle condition-based maintenance and testing is necessary to monitor deteriorating asset health. Based on asset health scores based on condition, failure risk, and availability for parts, as described in Part 1, the Company prioritizes maintenance requirements and retirements, and tracks asset health scores which are reported annually for planning reasons.

b. Condition Based Maintenance

DTE is working on using more remote monitoring via SCADA, and less time-based maintenance, to identify when breakers, relays, and substation transformers require condition-based maintenance, with the purpose of reducing maintenance costs while improving asset condition monitoring.

c. Improving Asset Management Processes

In the DGP, DTE indicates plans to invest nearly \$30 million from 2024 through 2028 to improve the management of its assets to minimize the costs of maintaining them while also improving asset caused reliability. It plans to improve the asset data in its Geographic Information system (“GIS”) and implement a distribution network to automatically update asset changes for the ADMS and planning tools. The new asset management tools will provide a real time assessment of asset location and health on a visible screen available to asset engineers and on mobile devices. Condition based maintenance primarily applies to substation transformers and oil circuit breakers.

2. Conclusions

14. DTE’s enhancements to its systems for supporting asset management are sound, but invite consideration of how best to continue to improve this function. (See Recommendation #4)

The changes made and continuing to be made will move the Company forward. We believe that best practice calls for assigning responsibility for ensuring effective application of a sound asset management program to a director-level role. We understand the importance of promoting the accountability of operations personnel making those in operations organizations responsible for operating and maintaining assets by emphasizing their “ownership” of the assets. Diminishing that sense of ownership can substantially mitigate an otherwise effective asset management program.

Others have found it possible to provide an empowered source, for example, in:

- Overseeing effectiveness in applying program elements in the field

- Providing insight into how realignment of resources among many divisions and locations competing for resources can better “level” performance results among them to produce optimized net results
- Providing the experience and insight necessary to continue program evolution as the “science” of asset management advances.

3. *Recommendations*

4. **With completion of the current changes contemplated in asset management measures, continue to assess the merits of moving to a more empowered organization, led at the director-level, responsible for ensuring optimized execution and continuing development and execution of the program.** *(See Conclusion #14)*

Best practice in our view favors such an approach, but we recognize that making it operate effectively requires a supportive culture and prevention of diminishment of asset “ownership” by those who direct and conduct work in the field. Central responsibility under a senior management individual reporting to the vice presidential level can bring more focus to keeping the program current with developments in the industry, ensure vetting and instituting new systems, tools, and methods, and, perhaps most importantly, ensuring a common level of focus and discipline on effective asset management across the full spectrum of asset types managed across different organizations. DTE has reported the recent creation of an Asset Management organization.

G. Inspection and Maintenance

1. *Findings*

Overhead distribution lines are exposed to wind, trees, and ice and any weak or broken components can cause outages under severe conditions. Reliability records must be used to identify the amount overhead distribution lines contribute to outages and to SAIDI. Balancing reliability and the cost of emergent outages caused by failures of equipment to the cost of maintaining these assets is the responsibility of an Asset Management organization.

a. *Equipment Caused SAIDI*

The next two tables summarize DTE’s reported causes of outages by asset type (Subtransmission, Substation and Distribution) excluding and including MEDs. Subtransmission and Substations have very little impact on SAIDI. The Distribution system accounts for 88 percent of the DTE SAIDI minutes in 2022 whether including or excluding MEDs.

Outage Cause by Asset Type – SAIDI

Year	Excluding MEDs			Year	All Weather		
	Subtrans	Substation	Distribution		Subtrans	Substation	Distribution
2013	0.233	0.000	43.448	2013	0.233	0.000	70.371
2014	0.164	0.000	47.851	2014	0.403	0.000	91.998
2015	0.177	0.800	50.553	2015	0.177	0.800	57.026
2016	3.842	3.469	46.973	2016	3.842	3.828	54.454
2017	3.201	6.956	55.397	2017	3.201	8.332	164.550
2018	9.255	1.927	48.445	2018	10.512	1.932	84.158
2019	4.727	1.140	49.281	2019	6.079	1.140	79.080
2020	4.902	0.144	43.097	2020	5.018	0.144	76.368
2021	2.082	0.044	41.985	2021	7.552	0.382	138.605
2022	4.531	2.127	47.710	2022	9.473	3.166	92.582

The next tables list the causes of equipment failures since 2018, in descending order by asset class.

Subtransmission Equipment Failure Causes

2022	2021	2020	2019	2018
Transformer	Reclo/Sect/BRK	Reclo/Sect/BRK	Conductor/Cable	Conductor/Cable
Reclo/Sect/BRK	Connections	Conductor/Cable	Reclo/Sect/BRK	Transformer
Conductor/Cable	Conductor/Cable	PTS / PSC switch	Crosarm/Standoff	Reclo/Sect/BRK
Insulator	Transformer	Fuse Cutout	Disconnect	Crosarm/Standoff
Mtr,relay,cntrl	Insulator	Transformer	Transformer	Pole or Struct

Distribution Equipment Failure Causes

2022	2021	2020	2019	2018
Conductor/Cable	Conductor/Cable	Conductor/Cable	Conductor/Cable	Conductor/Cable
Fuse	Fuse Cutout	Fuse Cutout	Fuse Cutout	Fuse Cutout
Transformer	Transformer	Transformer	Transformer	Transformer
Crosarm/Standoff	Pole or Struct	Pole or Struct	Pole or Struct	Pole or Struct
Pole or Struct	Reclo/Sect/BRK	Crosarm/Standoff	Reclo/Sect/BRK	Crosarm/Standoff

Substation Equipment Failure Causes

2022	2021	2020	2019	2018
Transformer	Reclo/Sect/BRK	Reclo/Sect/BRK	Reclo/Sect/BRK	Reclo/Sect/BRK
Reclo/Sect/BRK	Fuse	PTS / PSC switch	Conductor/Cable	PTS/PSC Switch
Conductor/Cable	Conductor/Cable	Conductor/Cable	Connections	Transformer
Fuse	Disconnect	Fuse Block	Fuse	Conductor/Cable
Capacitors	Transformer	Disconnect	Disconnect	Arrester

b. Overhead Circuits

Equipment Failures comprise a leading outage cause for DTE. The time between equipment inspections must be sufficiently short to identify and repair or replace broken or degraded asset components to minimize failures that cause outages. Common practice in our experience employs four-to-five year inspections of overhead circuits to identify pole and pole-top equipment as defective from visual inspection. These overhead circuit inspections need to form a central element of program methods and practices to prevent equipment failures. Common industry practice accompanies overhead circuit inspections with pole strength inspections, generally occurring at 12 to 15-year cycles, in our experience. These pole strength inspections of older poles (20 years of age is a common criterion) employ methods that include:

- Examining pole condition in total
- Excavating soil surrounding the pole base to below the ground line to examine for decay
- “Sounding” the pole with a hammer to identify voids from below the ground line to eight feet or so above the pole base
- Boring holes in the pole where voids are identified
- Measuring the thickness of the shell at the bore holes between the voids and the external pole surface to determine pole strength
- Applying chemicals on the pole base and in the voids to retard further deterioration from decay and insects.

Pole-strength inspections produce results that vary from: (a) acceptable, to (b) suitable for strengthening by installing a reinforcement device, to (c) rejection and thus scheduling for replacement. Note that visits to pole locations occur for other reasons as well; *e.g.*, inspection of facilities on poles jointly used with others, or trouble callouts. These visits have more limited scope or operate under the time pressures that emergent circumstances create. They do, however, provide other opportunities to “get eyes on” pole and pole-top equipment condition.

DTE does not employ the common industry practice of conducting four-to-five year visual overhead circuit inspections. Its inspections come under the Company’s PTMM and 4.8 kV Hardening programs, which include both visual overhead circuit inspections and pole strength testing on what has been a 20-year cycle. The Project Management organization manages both of these programs. These programs seek to reduce emergent capital and O&M costs and improve reliability and safety by replacing damaged and deteriorated poles and pole top equipment.

The PTMM program has operated on a roughly 20-year cycle, addressing about 1,500 miles per year of the system’s total 31,000 circuit miles. Planned 2023 work, however, covered only 1,000 miles, more in line with a 30-year cycle. Plans for completing the 4.8kV Hardening program will address all of the approximately 1,600 circuits it includes (677 miles addressed before 2023, 345 expected in 2023, and 589 remaining). Counting visits for other purposes, the time between “eyes on” poles and pole tops averages 12 to 13 years, as the next table shows.

Last Pole Visits

Years		Share	Weighted Duration
Range	Avg.		
0 to 5	2.5	13%	0.3
6 to 10	8	28%	2.2
11 to 15	13	27%	3.5
16 to 20	18	15%	2.7
21 to 25	23	13%	3.0
26 to 30	28	3%	0.8
Total		99%	12.7

PTMM inspections identify poles and equipment that fail visual examination. DTE generally replaces poles failing PTMM inspection and testing with higher class, stronger ones. Replacement of pole-top equipment that fails inspection similarly uses equivalents now in use and generally having greater durability and reliability. This enhancement upon replacement results in, for example, replacement of legacy wooden crossarms, porcelain cutouts, and porcelain insulators with fiberglass crossarms, polymer cutouts, and polymer insulators. DTE has enhanced its testing and inspection processes recently, considering other Northeast and Midwest utility practices, Rural Utility Bulletin 1730-121, and its pole failure performance. DTE reports that the enhancements have increased the identification of poles and pole-top equipment slated for replacement by two to three times.

A tree crew first clears circuits to allow safe and efficient access to equipment, after which PTMM and hardening work can proceed. Management prioritizes circuits for near-term inspection based on reliability criteria and on 4.8 kV System sectors where downed wires most expose the public to safety risk. DTE’s DGP plans to accelerate PTMM work to reduce the cycle for completing the entire distribution and subtransmission system to a 10-year cycle, and, as noted, to complete the hardening program on the remainder of the City of Detroit 4.8 kV system in 2026.

DTE commenced its 4.8 kV hardening and arc wire removal program in and around the City of Detroit in 2018, initially to respond to the need to remove the City’s long retired de-energized arc lighting circuit wires mounted on DTE poles. Fallen arc wires entangling with energized wires present a public safety hazard. The 4.8 kV Hardening program replaces or reinforces weak poles and upgrades the 4.8 kV pole top components to 13.2 kV rated equipment, preparing them for conversion to 13.2 kV. DTE also removes unused 4.8 kV service lines and primary circuits that no longer serve loads. Brush, trees, and other debris commonly obstruct access to the alleys that many of these 4.8kV circuits occupy. DTE does not plan to harden those 4.8 kV circuits scheduled under another program for conversion to 13.2 kV in the next several years to avoid duplication of effort.

The next table summarizes combined work units and investments historically and as planned under the DGP for the PTMM and 4.8 kV Hardening programs, poles replaced and reinforced and the number of poles replaced because of storms and other trouble. The last row shows poles replaced historically due to storms and other trouble circumstances such as vehicle hits.

PTMM and 4.8kV Hardening Work Summary

Category	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital \$	\$27.4	\$34.9	\$31.6	\$83.5	\$57.4	\$62.0	\$121.0	\$151.0	\$192.0	\$188.0
PTMM Circuit Miles Inspected	1,027	1,496	1,541	1,562	N/A	~700	1,604	2,043	2,651	2,651
PTMM Poles Inspected	58,100	2,400	25,300	131,000	12,650	1,700				
Poles Replaced	2,822	1,431	1,016	4,537	3,814					
Poles Reinforced	994	26	251	604	150					
4.8 kV Hardening Miles	128	209	203	475	371	145	296	154		
Subtransmission Circuits Inspected	18	3	7	12						
Distribution Circuits Inspected	132	43	101	259						
Other Pole Replacements	2,365	2,009	2,226	2,013	3319					

c. Overhead Devices

Overhead distribution and subtransmission circuits include poles, crossarms, insulators, and conductors. They also frequently include fused cutout switches, capacitors, voltage regulators, isolation transformers, service transformers, lightning arrestors, and reclosing devices. These components require time-based inspection and maintenance activities to continue to operate as required. Balancing reliability and the cost of emergent outages caused by failures of these assets to the cost of maintaining these assets is the responsibility of an Asset Management organization.

In addition to PTMM and 4.8 kV Hardening programs, the Distribution Regions inspect overhead circuit mounted devices such as capacitor banks, voltage regulators, and SCADA enabled reclosers on periodic cycles. As this table illustrates, the Company had backlogged approximately 46 percent of the SCADA devices (reclosers) at the end of 2022.

Backlog Summary

Activity	Target Inspection Cycle (Yrs.)	# of Devices	Year-End Backlog			
			2019	2020	2021	2022
40 kV PTS	4	870	32	46	59	76
SCADA Devices	1	1,455	652	466	673	719
Towers	10	322	3	82	-	10
Caps and Regulators	1	4,765	1,327	3,521	3,075	-
Device Battery Replacements	4	1,455	148	166	213	60
Equipment in High Rise Structures	45	20	-	-	6	5

d. Subtransmission Underground System

DTE’s system includes over 1,200 miles of underground subtransmission circuits. Balancing reliability and the cost of emergent outages caused by failures of subtransmission underground cables to the cost of maintaining these assets is the responsibility of an Asset Management organization.

DTE’s Subtransmission Planning Engineering group monitors the condition and needs of the subtransmission underground system. The DTE underground subtransmission system includes 732 circuit miles of 24kV cable, 465 circuit miles of 40kV cable, and eight circuit miles of 120kV cable. Between years 2019 and 2023, DTE experienced 369 subtransmission cable failures: two hundred and seven (207) 24kV cable failures (41 per year average), one hundred and sixty-one (161) 40kV cable failures (32 per year average). By contrast, it experienced only one 120kV cable failure. Subtransmission cable failures generally result in transfer by automatic transfer switches

of distribution substation loads to other circuits. However, DTE has experienced loss of one or more distribution substations resulting in outages for customers served because of insufficient capacity of the alternate circuit, because the alternate circuit had also failed, or because its substation transformer is shut down for maintenance. DTE then must conduct costly emergent work, including making ties to other adjacent substation circuits or by deploying mobile generation.

e. System Mainline Feeder Cables

In addition to subtransmission cables, distribution system cables provide an underground distribution system's backbone. System cable failures may result in a large number of customer interruptions and emergent CapEx and O&M costs. Balancing reliability and the cost of emergent outages caused by system cable failures to the cost of maintaining these assets is the responsibility of an Asset Management organization. DTE's underground system circuits include approximately 2,534 miles of mainline "system" cable circuits; *i.e.*, excluding URD. Between years 2019 and 2022 DTE experienced 615 mainline system cable failures.

Approximately 30 percent of DTE's electric system consists of underground facilities, much of them extremely aged. Approximately 80 percent of the system cable is vintage lead sheath PILC (paper insulated lead covered oil filled cable) or gas-insulated cable. Nineteen percent of DTE's vintage 4.8 kV PILC system cable system cable was installed before 1910.

Utilities generally limit underground cable maintenance to reactive repair or replacement. Other than possibly injecting underground residential distribution ("URD") cables, proactive cable replacement offers the only way to reduce cable-caused outages. DTE's Regional Customer Operations group and Equipment Engineering group monitor the condition and needs of the distribution system underground cable, which has an average age approaching 50 years. Workers in the Southeast Service Center that DTE refers to as the "Trombley Service Center" have responsibility for pulling, testing, and splicing system cables. DTE uses contractors for directional boring when replacing URD cables and DTE personnel repair and make final URD terminations. DTE employees utilize various methods for testing the condition of cable.

DTE experienced 615 system cable failures¹ during the years 2019 to 2023, including 4.8 kV, 8.3 kV, and 13.2 kV facilities. Approximately 72 percent of the failures occurred on 4.8 kV system cable. DTE reports that it proactively replaces system cable based on a criteria and ranking matrix including number of failures, cable loading, type of insulation and age for PILC cable.

Whether for subtransmission or distribution, DTE's mainline "system" cables run through conduit, usually in concrete-encased ducts for protection. The majority of DTE system cables operate radially, but DTE has designed redundancy in its underground system cable circuits by forming circuit loops or by having spare cable in place. Some circuits in downtown Detroit and Ann Arbor operate in a looped configuration. Otherwise, system cable has an energized parallel back up cable. If a substation circuit exit cable fails, the load manually or automatically transfers to backup cable circuit by operation of a transfer switch at street level or on a pole. Cable circuit sections running through manholes have lengths less than 500 feet long. When a system cable fails between

¹ DTE also provided an inconsistent number of 887 system cable failures from 2019 through 2022.

manholes, the faulted section is replaced, while circuit load is transferred to another cable. However, if the backup cable fails, and the load cannot be transferred, the result may be an extended customer outage and high emergent O&M costs. DTE sometimes uses generators as needed to provide capacity during cable repairs.

Between years 2019 and 2023 DTE experienced 615 mainline system cable failures. DTE replaces vintage PILC cable with modern Ethelene Propylene Rubber insulated cable. DTE ranks system cables for replacement based on a matrix of criteria, including loading, type of insulation, and the number of failures; and including age for PILC cables. During the years 2019 to 2022, DTE replaced approximately 164 miles of system cable, of which 83 percent was due to failures and 17 percent due to proactive replacements. Other utilities with significant amounts of PILC cable still in operation follow generally similar practices.

At the beginning of 2024, DTE had a backlog of 25 system cable repair/replacement projects open. Until a system cable repair or replacement system redundancy is unavailable, DTE's goal is to keep the backlog of system cable restoration under 30 projects, but it sometimes reaches 50 projects backlogged during summer months. DTE annually ranks the need for replacing its mainline system cables based on failure history, on the type of cable insulation, on loading conditions, and on age for paper insulated, lead-covered PILC cable.

f. URD Cables

Utilities began installing URD cables in subdivisions and business centers in the late 1960s and early 1970s. The early installed URD cables have high failure rates, and it was not until the mid-1980s that the quality of URD became sufficient to withstand the effects of moisture on the insulation and exposed neutral wire. The Company should be repairing or replacing failed URD cable segments in a URD loop within a reasonable time to provide redundancy for customers. Balancing reliability and the cost of emergent outages caused by failures of URD cables to the cost of proactive replacement or rejuvenation is the responsibility of an Asset Management organization.

Approximately 89 percent of the URD cables operate at 13.2 kV. Between 2019 and 2023, DTE experienced 4,264 URD cable failures. DTE uses URD cable for lateral single-phase distribution primary circuits usually formed in circuit loops to serve residential customers and three phase circuits for commercial customers. The URD loops provide redundancy if a cable segment fails. However, until a failed segment is repaired or replaced, some customers are exposed to extended interruptions if a second segment in the loop fails.

The type of direct buried URD cable installed by electric utilities before the mid-1980s is subject to multiple insulation failures because the cable was not sufficiently designed to withstand water intrusion and corrosion of unjacketed neutral conductors. Because of high failure rates, utilities typically have URD cable replacement programs for pre-1986 vintage URD cable. Modern, more reliable jacketed direct buried URD cable has a life expectancy of more than 40 years.

DTE places priority on restoring URD cable loops, and its target for restoring URD loops is 60 days. DTE replaces pre-1986 unjacketed URD cable after two or more failures. DTE digs up a failed cable and repairs the cable with a splice. DTE reports it relies on the number of cable failures

and other factors when replacing URD cable, such as unjacketed pre-1986 URD cables. As of November 15, 2023, DTE had 488 open URD loops being monitored in its Maximo and Sharepoint systems monitored by the Service Centers. When an URD loop is open, meaning that a cable in the loop fails and is out of service, if a second cable in the loop also fails then some customers will experience a long duration interruption until one of the cables is repaired.

Under its cable rejuvenation program, Consumers Energy has been injecting its URD cable for 60 percent less cost than for replacing URD cables with successful results. DTE has not considered injecting its URD cables and has no plans to rejuvenate URD cables. DTE was an early adopter of rejuvenating its URD cables in 1998, but after a bad experience with the fluid injection process, stopped using the method and no longer considers doing so. Of 178 total cables it injected in 1998, 17 failed between 2011 and 2023. DTE uses larger 4/0 and 350 kcmil conductor in addition to No. 2 conductor in its URD circuits. That size may prevent it from using injection on some of its URD cables. Consumers Energy has found limits to its low pressure injection method at cable sizes greater than 3/0.

g. Underground Equipment Backlogs

This next tables summarizes inspection cycles for underground switch cabinets, padmount transformers, and manholes. The data show significant padmount transformer and manhole inspection backlogs

Asset	Target Cycle (Years)	Number of Devices	Backlog			
			2019	2020	2021	2022
Primary Switch Cabinets	5/20/15	1,731	61	191	196	112
Manholes	10	18,035	6,193	4,582	3,575	2,345
Padmount Transformers	10	145,610	No Program	145,610	145,610	126,191

Surface-mounted padmount transformers are the service transformers used to connect customers to underground cable circuits. The issue is that these can be damaged by vandals who remove locks that prevent public access to energized parts. Padmount transformers and switchgear should be periodically inspected for safety reasons. DTE’s underground system dates to the early 20th century as do a number of remaining manholes. Manholes should be systematically inspected for safety conditions, damaged cable splices, and crushed cable duct.

DTE underground distribution circuits provide the connection between substations and padmount (on surface) transformers that serve one or more customers. DTE has approximately 146,000 padmount transformers. Although padmount equipment cabinets are locked to provide safety to the public, locks can be vandalized. Conducting periodic inspections is required to ensure that padmount transformers and switchgear do not expose the public to an electrical hazard. DTE suspended its padmount transformer inspection program more than 12 years ago. DTE restarted in 2022 the inspection of the transformers for hazards and locks and to apply warning labels. Live front transformers are on a 10-year cycle and dead front switchgear is on a 15-year cycle, or on a five-year cycle in areas of heavy contamination. All but approximately 350 padmount transformers are identified in the asset management program and approximately 90 percent of the padmount transformers are identified in the GIS system. DTE had a backlog of 126,191 padmount inspections as of the end of 2022.

DTE’s acquisition of the Pontiac 8.3 kV system in the 1980s included 33 electric vaults located under sidewalks containing transformers and switchgear with exposed live parts. DTE reported plans to retire some of these vaults, upgrade approximately 10 of them by 2024, and upgrade the remainder by 2030. These vaults had exposed live parts and confined spaces in the vaults present safety and operational issues, including the unavailability of minimum arc flash working distances, the need to de-energize for inspection and maintenance, and the unavailability of obsolete spare parts. Circumstances like these contribute to the time required to restore service to customers. Balancing reliability and the cost of emergent outages caused by conditions in manholes to the cost of maintaining these assets is the responsibility of an Asset Management organization.

DTE’s underground system cables, some of which are over 100 years old, run through conduits between approximately 18,000 manholes in all four DTE Regions. Cables running conduits or duct banks pass through the manholes and lay together on wall racks. Cable sections are spliced in these manholes. Some of the manholes are made of bricks or asbestos and face issues that include leaking splices, fallen racks, collapsed conduits, and manhole cover issues. DTE targets a 10-year manhole inspection cycle, but reported that it can only fund the most overdue manhole inspections. DTE had a backlog of 2,345 manhole inspections as of end of 2022. As illustrated by this table, the average annual number of manholes inspected between 2019 and 2023 was 1,100, equivalent to a 17-year manhole inspection cycle.

Manhole Inspections

2019	2020	2021	2022	2023
1,477	1,064	851	1,500	501

h. Substations Inspections and Maintenance

DTE conducts visual inspections of the assets in its substations on monthly cycles and infrared inspections (for overheated connections and transformers) every three years. The next table indicates the total numbers of each type of asset, the asset type, the maintenance cycles, and the Company’s backlog of maintenance tasks at the end of each year.

Substation Inspection Summary

Activity	Cycle	System Devices	Year End Backlog			
			2019	2020	2021	2022
120 kV Breakers	10/12	31	4	0	0	0
120 kV Breakers	10	371	234	162	136	35
40 kV Breakers	3/10/12	493	121	38	32	18
40 kV Gas Breakers	12	536	77	10	136	168
Distribution Breakers	3/10/12	5,360	265	79	120	100
Buses	10	238	51	33	46	31
Regulators	10	373	83	34	28	25
Single Tap Substations	10	120	65	54	54	35
Portable Subs	1	14	1	2	4	1
AC Net Banks	5	505	65	51	37	16
AC Structures	10	368	0	0	0	0
13.2 kV Enclosed Cap Banks	1	231	0	0	0	0
Station Batteries	1	651	0	0	0	0
Voltage Controls	1	1,717	0	439	0	0
Relays NERC	3/7/9	603	0	0	0	0
Relays Non-NERC	3/7/10	9,284	4,335	5,680	5,736	5,816
Substation Poles	10	-	-		450	446
DGA	1	3,369	0	0	0	0
SPdm (Infrared)	3	2,162	0	0	0	0

2. *Conclusions*

15. The longer cycles of the PTMM and the Detroit 4.8 kV Hardening programs do not meet requirements for a more frequent overhead circuit inspection program. (See Recommendation #5)

DTE does not conduct the four-to-five year visual overhead circuit inspection program cycles its benchmarking and our experience demonstrate as typical. The current 20-year PTMM cycle falls well outside the range of good practice. DTE’s 2023 plans did not even meet the level of work needed to sustain a 20-year cycle. The planned 1,000 circuit miles for 2023 better reflected a 30-year duration. Even planned movement to a ten-year PTMM cycle (accompanied by completion of 4.8kV Hardening) falls well beyond the range of utility practice, as demonstrated by typical overhead circuit inspection programs.

Distribution equipment failure has remained a major cause of outages for DTE. As we believe DTE acknowledges, the Company needs to gain first the visual control over its system that more frequent inspections will bring, followed by the physical control that will come by repairing and replacing broken or deteriorated poles and pole-top equipment that pose immediate threats. DTE has recently provided information that demonstrates large cost increases from moving to cycles that it appears to agree it needs. That information indicates pole and equipment repair and replacement rates well in excess of those that appear to underlie projected costs of the first years (2027 and 2028) under which plans call for employing a ten-year PTMM cycle.

The potential for such large costs makes it appropriate to consider how to lessen the scale of work called for under a first four-to-five year overhead circuit inspection cycle, in order to mitigate first cycle costs. After the first cycle, costs will drop significantly; over time, both shorter and longer cycles should produce roughly the same repair and replacement rates. Thus, the principal challenge

lies in finding ways to spread over a longer duration the costs of repairs and replacements identified from completing the inspections within the first cycle's duration.

We did not find a source of reliable DTE data or analysis for estimating the first and subsequent cycle costs for instituting an industry-standard overhead circuit inspection program. DTE needs to establish one to craft such a program, taking proper account of short-and long-term costs implications. Several factors make estimating problematic now:

- The long durations between inspections leave DTE without good “visual control” of its system; *i.e.*, knowledge of the full scope of work needed to produce understanding of overall repair and replacement work levels and the cost estimates those levels will drive
- The long durations between inspections and repair that have applied on the DTE system clearly will require a much more costly first shortened cycle to get the system on a four to five year cycle that can be sustained
- PTMM standards, methods, and scope expansion create unit costs well in excess of what is needed to address immediate threats from poor equipment condition; the size of DTE's challenge makes scaling back of first cycle work important in establishing an affordable path toward sustainably short inspection cycles over the longer term
- The high rates of defects DTE reports finding now, under expanded PTMM standards, methods, and scope help in identifying immediate term needs, but likely well overstate rates that should decline substantially as continuing work progresses over time
- With overhead circuit equipment failure so large a cause of outages, shortening inspection and repair/replacement cycles should substantially reduce restoration capital and O&M expenditures, thus significantly offsetting the increased costs of the shorter cycle
- With the entire system covered at the end of a shortened cycle, costs per mile will come down very substantially as compared with continuation under a longer cycle.

The PTMM and Detroit 4.8 kV Hardening programs certainly have contributed to reliability improvement, but the current 20-year cycle and even the proposed 10-year cycle allow damaged and deteriorated equipment to continue to pose reliability threats for too long. They also contribute to higher restoration costs. Over time, apart from the costs of more frequent inspections themselves, a shortened cycle will not produce greater repair and replacement costs than will a longer cycle. Where replacement is required, use of modern equipment is appropriate, but with so many competing needs for capital and O&M programs and work, scaling back the scope of replacement work and deferring less critical work items over a first shortened cycle require exploration by DTE. Gaining full control over the system across the first cycle and keeping it through more frequent inspections will contribute to reliability improvement and reduced restoration costs that, as others in the industry commonly find, are worth the costs of those inspections.

16. DTE conducts typical inspection and maintenance practices for distribution devices but has experienced large backlogs in addressing inspection results. (See Recommendation #6)

DTE's inspection and maintenance practices and cycles for distribution devices are consistent with good utility practices. However, we found the backlog of SCADA devices (reclosers) at the end of 2022 very high. While it is normal to schedule some work for next year completion, a 50 percent backlog is too high.

17. DTE’s subtransmission cable failure rate has been too high. *(See Recommendation #7)*

The 737 failures in five years exceeds what one should expect. One should expect minimum numbers of subtransmission cable failures.

18. DTE has experienced excessive mainline system cable failure rates. *(See Recommendation #8)*

The failure rate of DTE’s mainline system cables (615 over five years) is excessive and beyond that expected by electric utilities. One should expect minimum numbers of mainline system cable failures.

19. DTE experiences a comparatively high number of URD cable failures which results in a high number of backlogged repairs. *(See Recommendations #9 and 10)*

Its nearly 1,000 failures per year is high compared to other utilities with similar numbers of URD loops. The high backlog of 488 cable segments that require repair is material; the lack of redundancy pending repair exposes customers to long interruptions on failure of another cable in the loop.

20. Apparent advances in rejuvenation warrant reconsideration of its use in addressing URD cable. *(See Recommendation #9)*

The circumstances at DTE and Consumers differ. Nevertheless, the promising use of rejuvenation (injection of fluid insulation) at Consumers warrants its examination by DTE, recognizing advances since the unsuccessful application DTE made of the practice historically.

21. Recent restoration of padmount inspections has resulted in a very large backlog. *(See Recommendation #11)*

Since resuming padmount inspections, DTE has not inspected them at rates consistent with its 10-year cycle, producing an extremely large inspection backlog not consistent with good practice. Its 10-year cycle also exceeds the more normal five- to six-year cycles we have seen elsewhere.

22. DTE faces substantial operating and safety issues with its manholes. *(See Recommendation #12)*

DTE has not been inspecting its 18,000 manholes on its targeted 10- year cycle. DTE’s performance of approximately 1,100 inspections per year produces a cycle of approximately 17 years.

23. DTE’s monthly substation inspection and circuit breaker maintenance programs and cycles conform to common industry practice, but should employ expanded measures. *(See Recommendation #13)*

DTE employs annual dissolved gas analysis testing and oil dielectric strength testing to monitor substation transformer condition. It does not perform annual infrared inspections or conduct regularly-cycled testing of transformer oil for acidity and interfacial tension.

3. Recommendations

5. **Adopt a four-to-five year visual overhead circuit inspection program, focusing on securing visual control of the system and adjusting repair/replacement scope in the first cycle to account for what can be expected to be very high first-cycle costs.** (See Conclusion #15)

Both the current PTMM cycle and the proposed 10-year one are too long to allow the identification and remediation of immediate equipment failure threats. Visual pole and pole-top equipment inspections need to be brought under a four-to-five year cycle. While we consider this a priority, it remains important as well to recognize that the early-year costs of doing so are likely to be significantly higher than what DTE has proposed under its 10-year cycled PTMM program.

DTE has provided an estimate of the difference, employing the results of inspection reject rates it has been experiencing of late. Given work to date on circuits prioritized by performance, those reject rates should prove significantly higher than those one should expect as the cycle proceeds to ever lower priority circuits until reaching the entire system. It also needs to be recognized that work, and therefore costs per year on a four-year cycle, will be higher. However, once having addressed the entire system, this cycle will lead to much reduced costs for the following years. Over time, a shorter cycle will not produce greater work. However, it will remove damaged and deteriorated poles and equipment more timely from the system and reduce restoration costs.

Getting inspections completed on schedule comprises the first priority over this recommended first four-year overhead circuit inspection program cycle. The reason is to establish visual control over the system. This control will come from establishing with a useful degree of certainty, how much out there is defective, where it is, and what needs to be done to get physical control by repairing and replacing poles and pole-top equipment. Making substantial progress on repairs and replacement is also critical, but measures to spread out the expected high first-cycle costs are likely in order, given the many other needs on the DTE system. The Company can, through sound prioritization, defer some of the less critical work that can be bundled for completion later. DTE should also revisit its recent PTMM changes that have more than doubled the identification of poles and equipment slated for replacement. That examination should seek to identify provisional measures that would mitigate first-cycle cost increases. Measures of this type can spread out early-year cost increases under the needed shorter pole and pole-top equipment inspection cycle.

DTE also needs to undertake two important refinements in estimating the costs of this cycle change. First, it needs to determine how fast defect rates will fall as it proceeds through the entire body of overhead circuits and apply that rate of decline uniquely to a ten versus four or five year cycle. The decline will happen much faster under shorter cycles, which address work needed on circuits at twice the pace. Second, there is a clear connection between correction of pole and pole-top equipment rates and the amount of emergent work required as system defects are eliminated faster. Understanding the cost consequences of declining repair and replacement needs and of reduced restoration costs are essential to designing a plan for introducing a more industry typical overhead circuit inspection cycle over a period that spreads out first cycle costs without unduly delaying the gaining of visual control over the system and getting highest priority work done.

In the long run, the shorter cycle is clearly preferable for reliability purposes and can serve those purposes without cost penalties. The issue here is finding a way to get visual control over poles and pole-top equipment promptly, to address as many threatening conditions as practicable in the short term given other costly demands, and to reach over a reasonable period of time an acceptable steady state. Substantial data needs and DTE analysis are required to do these things.

Management should also ensure a future practice that pole replacements be condition-based, not age-based.

6. Clear SCADA device backlogs. *(See Conclusion #16)*

The backlog of some overhead distribution devices (SCADA reclosers) was excessive at the end of 2022. The Company should maintain assets as scheduled. Once the backlog is cleared, DTE should examine whether it remains necessary to stay on the same inspection and maintenance cycle.

7. Plan for replacement of poor-performing subtransmission cable types over the long term. *(See Conclusion #17)*

The next chapter of this report addresses DGP plans and investment levels for addressing subtransmission cable.

8. Plan a long-term program to replace poor performing types of mainline system cables. *(See Conclusion #18)*

The next chapter of this report addresses DGP plans and investment levels for addressing mainline system cable.

9. Continue proactive URD cable replacement, assessing the potential for using rejuvenation as a method. *(See Conclusions #19 and 20)*

Proactive replacement is an industry accepted method for addressing vintage cable whose multiple failures cause long outage durations and are expensive to continue to repair. However, experience at Consumers indicates significant merit in examining rejuvenation for cable sizes to which it may apply. The next chapter of this report addresses DGP plans and investment levels for addressing URD cable.

10. Dedicate the resources required to manage the high number of backlogged loop repairs. *(See Conclusion #19)*

Distribution Operations management and work management should ensure that resources are available to repair or replace failed cables in URD loops within 30 days or less.

11. Provide the resources to reduce the padmount transformer inspection backlog and determine an optimum inspection cycle. *(See Conclusion #21)*

The first challenge is to bring the backlog to a reasonable level. After doing so, management will have sufficient results data to determine whether its 10-year cycle should be reduced to a more customary five to six years.

12. Complete manhole inspections on the established cycle. *(See Conclusion #22)*

The Company should sufficiently fund its system-wide manhole inspection program to complete manhole inspections on its conservative 10-year cycle.

13. Evaluate the cyclical conduct of substation infrared and oil testing. *(See Conclusion #23)*

DTE’s operations have stressed its substation transformers beyond what we have typically seen. Therefore, DTE should examine whether it should consider: (a) conducting substation equipment infrared inspections on an annual basis and (b) testing transformer oil for acidity interfacial tension on a 3-year cycle to monitor oil conditions that lead to insulation deterioration and transformer failure. The oil tests are a standard test according to the International Electrical Testing Association. These inspections and tests can be done at fairly nominal costs.

H. System Operations

1. Findings

System Operations has responsibility for monitoring and controlling the electric system. System Operations also directly dispatches first responders and crews to address trouble reports, critical in ensuring reliability. System Operators have responsibility for ensuring that the electric grid operates within design voltage and load criteria, identifying and monitoring for abnormal grid voltages and current flows in real time. They also work with dispatchers and responders to identify circuit fault locations. System Operations, under the Director of System Operations, manages the emergent work assignments of the RCO line specialists and substation operators and crews. The next table indicates the employee FTEs assigned to the System Operations Organization.

System Operations Center FTEs

2019	2020	2021	2022	2023
154	153	152	170	157

The new DTE eSOC, which the Company opened in 2022, has brought significant enhancement to operations monitoring and control capabilities. It enhances internal system operations communications by co-locating the Dispatchers, System Operators, support engineers, an IT team, a mapping team and the SCADA support team, who have access to modern system displays and improved tools for monitoring and controlling the system.

Dispatchers communicate with on-duty first responders called line specialists to take trouble calls. DTE assigns journeymen as line specialists during day shifts in numbers determined by numbers of trouble calls. Outside normal hours, DTE provides for 24/7 coverage adding to these day shift resources line specialists assigned to the service centers. These additional assignments use eight hour shifts for evening and morning hours and 16 hour shifts (7:30am to 11:30pm and 11:30pm to 3:30pm) for the weekends. These service center assignments typically include from one to four line specialists at each service center outside normal hour shifts. As required, a line specialist can move to another service center to address high volumes. However, our review of schedules showed some shifts for which no assignments were evident for several service centers.

About the same time that System Operations and Dispatch moved into the new Center, the Company implemented its Advanced Distribution Management System (“ADMS”). Prior to that, System Operations personnel had access to the Supervisory and Data Acquisition (“SCADA”)

system, the eMap GIS, the OMS, the Energy Management System (“EMS”) and state estimator for subtransmission, the Advanced Metering Infrastructure (“AMI”) system, the Customer Information System, and Smart Sensor data. The ADMS integrated a new OMS application with those functions as well as providing the platform for future applications including:

- Fault sensor data presentation on the SO’s monitor for fault locating
- Improved load flow analyses
- Identifying available fault current at any location on eMap
- Distribution circuit power flow estimator
- Voltage and reactive current optimization
- Coordination of protective devices
- Distributed Energy Resource Management System (“DERMS”).

Adding Fault Location Isolation and Service Restoration (“FLISR”) comprises a primary next step in the continuing development of ADMS at DTE. FLISR uses fault sensor data to identify fault locations automatically and then determines any switching appropriate to transfer load in consideration of historical and forecast load and weather data. FLISR-supported switching can occur automatically or by system operator action. DTE has individual automatic loop schemes, but FLISR can address the entire grid when accompanied by sufficient remote-controlled switching. DTE is installing additional SCADA enabled fault sensors and reclosers for sectionalizing and circuit tying to expand FLISR capability.

2. Conclusions

24. DTE operations employ a sound organization, eSOC, and monitoring and control procedures, systems, and tools to manage grid operation effectively.

DTE operates a well-equipped eSOC, staffs it adequately, and has co-located a broad array of resources to support communications needs, important at all times, and critical in system upset conditions. The advances that DTE has made in its ADMS comport with industry practice and support material improvement in system monitoring and communication.

25. Assignment of line specialists as first responders comports with good practice, but needs to ensure coverage for service centers with small or shared coverage. (See Recommendation #14)

DTE provides 24/7 coverage by qualified field personnel and considers trouble call numbers in determining how many to locate at each service center. However, numbers assigned, particularly to areas where line specialists cover multiple service centers, may contribute to longer outage durations at some locations.

3. Recommendations

14. Examine means for reducing outage durations at service centers where they commonly prove outlying by re-examining line specialist assignment. (See Conclusion #25)

Significantly longer interruption durations in some service centers appear to be recurrent. Smaller numbers of customers may mean that faster response and restoration times will not affect overall system reliability substantially. However, DTE should examine factors driving response and

restoration time in recurrently anomalous interruption durations to determine how to improve reliability measures, and use the information to optimize first responder resource levels and locations.

I. Forestry

1. Findings

Tree and large limb contact on conductors can reduce the strength of the conductors and supporting structures. Tree contacts with overhead power lines, especially during adverse weather conditions, represent a leading cause of power outages at DTE. Maintaining sufficient clearance between tree branches and wires during trimming cycles seeks to prevent contact in all weather conditions. Additionally, management must identify and address on and off right-of-way dead or dying trees that could fall onto power lines. Fallen trees significantly contribute to outages during severe storms. Effective grid operation across the DTE service territory requires comprehensive and effective vegetation management programs aimed at reducing tree contact and ensuring electric reliability. This section examines the impact of vegetation management programs, subtransmission and distribution circuits cycle times, and management’s approach to developing and employing sound trimming standards. We also address spending on vegetation management.

a. Forestry Management and Staffing

The Director of Tree Trim has responsibility for the Tree Trim program, field operations, and vegetation contractor management. As of 2023, the Tree Trim organization included 35 personnel including manager, supervisor, and arborist positions. This level reflected a drop from 2022’s 41 persons. The Tree Trim Team provides contractors with lists of circuits for trimming each year, and the contractors respond with trimming plans. Contract Planners track trim completion work using the work management system and DTE and ECI foresters inspect and audit the work completed. Contractors must correct unsatisfactory work.

Before removing hazard trees, the Company’s Tree Planners contact tree owners for approval by telephone or by leaving a door card signature. Owners here, as generally true, can refuse removal of their trees, and the Tree Planners may not be able to locate owners or may encounter abandoned property.

The next table summarizes average annual tree trim contractor personnel, expressed on an FTE basis. The average tree crew includes 3.5 personnel. In 2022 extra personnel were contracted for the surge of trim work that year.

**Contractor Tree
Trim FTEs**

Year	FTEs
2019	1,133
2020	1,164
2021	1,256
2022	1,639
2023	1,180

b. Tree Trim Specifications and Cycles

DTE began applying an Enhanced Tree Trimming Program (“ETTP”) in 2016. The program seeks to execute trimming under the program’s Enhanced Specification on all of the system’s 31,000 overhead circuit miles by the end of 2025. The new ETTP standard for subtransmission (40 kV) circuits calls for ground clearing to 20 feet from the pole, tree trimming to produce a clearance of 15 feet from conductors, no overhanging limbs, and removal of hazard trees 35 feet from the pole. Distribution overhead lines standards call for ground clearing to 15 feet, trees trimmed to produce a clearance of ten feet from conductors, and removal of hazard trees outside of 25 feet from the pole. DTE considers spans from the substation to the first protective device as comprising its first protective zone. Standards call for removal of all overhanging limbs to the sky in the first protective zone. The standards allow overhangs more than 10 feet above conductors, including lateral circuits, in the remaining zones. Remaining overhang must be trimmed to 45 degrees defined relative to ground, with no dead overhang remaining. About 80 percent of DTE’s trim work must take place in backlots off roadways, where lack of bucket truck access requires climbing trees to perform trim work. The extent of these conditions makes clearing more difficult to perform than what we have typically seen in the industry.

DTE has employed since 2019 a program to “surge,” or intensify, tree trimming to bring the entire subtransmission system to a three-year cycle and the distribution system to a five-year cycle by the end of 2025. DTE plans to continue these cycles after the 2025 completion of the surge. Recognizing the stress on local tree crews that such cycles present, the Company funds a Tree Trimming Academy to qualify through training applicants, primarily from Detroit as a first-level Woodsman and secure for them additional IBEW Local 17 “boot camp” training.

The Company is exploring whether to later shorten the five-year cycle to four years for some distribution circuits or protective zones, maintaining the five-year cycle for some circuit zones and increasing it to six years for others. Management has developed a risk-based model that considers tree density and tree species growth rates to identify protective zones at greater risk of tree contact. This model will help determine optimum trim cycles and where to apply mid-cycle, hot spot trimming of identified circuit protective zones before storms. Surge trimming has not generally included mid-cycle or hot spot trimming, except for instances of customer complaints, to focus resources on bringing the entire system to the planned cycles. There have been some exceptions, such as the short cycle work under the Customer Excellence program. DTE plans to conduct more extensive hot spot trimming after surge completion, supported by the new model’s operation. Management also trims at locations where it has planned PTMM, 4.8 kV conversion, and 4.8 kV hardening work.

DTE applies new work management processes and cost analyses to identify opportunities to improve efficiency once steady-state cycles begin to apply in 2026, targeting a 40 percent reduction in cost from completing the initial surge. We did not find that target unrealistic, given experience elsewhere with steady state flight cycles following substantial “catch-up” efforts on circuits previously cleared much less frequently.

c. Tree Caused Outage Metrics

DTE’s 2023 Grid Plan observes that trees cause two-thirds of the time customers spend without power. Tree and limb falls can cause excessive damage to conductors, crossarms and poles. About

40 percent of DTE’s system operates on small-diameter poles that have lower strength than do those now typically employed for rebuilding existing circuits and installing new ones. These legacy poles that still operate are not inherently or categorically unfit for service. However, their greater susceptibility to failure from tree contact underscores the risks of insufficiently frequent and complete vegetation treatment. The next table shows that tree contact with overhead lines proved the largest cause of 2022 customer outages in all weather conditions and the second highest in 2022 and 2023.

Number of Customer Outages by Cause

Cause Code	2021		2022		2023	
	Number	Percent	Number	Percent	Number	Percent
Equipment Failure	752,702	21.04%	904,204	31.48%	906,649	27.79%
Tree	793,472	22.18%	508,376	17.70%	740,012	22.68%
Wind	212,297	5.93%	391,864	13.64%	706,454	21.65%
Weather (Lightning & Ice)	690,014	19.29%	115,097	4.01%	371,890	11.40%
Intentional	214,571	6.00%	163,167	5.68%	195,967	6.01%
Animal	95,736	2.68%	125,240	4.36%	130,172	3.99%
No Issues Found	160,433	4.48%	131,491	4.58%	118,026	3.62%
Public Interference	58,763	1.64%	73,999	2.58%	42,648	1.31%
Unknown (Removed in 2023)	211,208	5.90%	85,027	2.96%	23,646	0.72%
Equipment Loading	20,733	0.58%	12,650	0.44%	14,173	0.43%
Other	340,784	9.53%	348,794	12.14%	6,483	0.20%
Customer Equipment	1,308	0.04%	1,988	0.07%	4,876	0.15%
Meter/Blocks (New)	-	0.00%	-	0.00%	1,422	0.04%
Switch	25,746	0.72%	10,555	0.37%	84	0.00%
Total	3,577,767	100.00%	2,872,452	100.00%	3,262,502	100.00%

Distribution circuits suffer the greatest tree consequences as measured by SAIFI and SAIDI. The next two tables summarize numbers (SAIFI) and minutes (SAIDI) of customer interruption from tree-related causes since 2013.

Tree-Related SAIFI

Year	Excluding MEDs			Year	All Weather		
	Subtrans	Substation	Distribution		Subtrans	Substation	Distribution
2013	0.001	0.000	0.121	2013	0.001	0.000	0.196
2014	0.000	0.000	0.127	2014	0.000	0.000	0.233
2015	0.001	0.000	0.165	2015	0.001	0.000	0.204
2016	0.010	0.000	0.193	2016	0.010	0.001	0.207
2017	0.007	0.002	0.238	2017	0.007	0.003	0.360
2018	0.014	0.001	0.177	2018	0.015	0.001	0.271
2019	0.009	0.000	0.210	2019	0.012	0.000	0.285
2020	0.002	0.000	0.155	2020	0.003	0.000	0.241
2021	0.004	0.000	0.145	2021	0.010	0.000	0.352
2022	0.003	0.000	0.121	2022	0.009	0.000	0.216

Tree-Related SAIDI

Year	Excluding MEDs			Year	All Weather		
	Subtrans	Substation	Distribution		Subtrans	Substation	Distribution
2013	0.11	0.00	42.17	2013	0.11	0.00	124.68
2014	0.00	0.00	42.05	2014	0.00	0.00	185.55
2015	0.35	0.06	45.82	2015	0.35	0.06	80.96
2016	1.76	0.00	48.07	2016	1.76	0.34	58.95
2017	0.62	0.20	59.77	2017	0.62	3.11	343.29
2018	3.10	0.06	46.40	2018	4.57	0.06	140.33
2019	2.43	0.19	56.86	2019	4.08	0.19	153.54
2020	0.35	0.00	34.14	2020	0.71	0.00	112.79
2021	1.10	0.00	34.92	2021	13.30	0.00	332.57
2022	1.05	0.36	28.70	2022	17.04	0.36	196.25

Tree-caused outages on the distribution circuit primaries caused virtually all (more than 96 percent) of all-weather tree-caused customer interruptions (SAIFI) in 2022 with the remaining 4.0 percent on subtransmission lines. As measured by all-weather SAIDI, distribution circuit primaries also bear nearly all the impacts of tree-caused outages e.g., 92 percent in 2022.

d. Trim Miles and Costs

The next table summarizes miles of circuit rights of way trimmed since 2021 and those planned through 2027. DTE recently provided updated planned miles on a combined distribution and subtransmission basis. Surge completion in 2025 will produce annual trimming requirements of approximately 6,000 circuit miles (5,300 distribution and 700 subtransmission) to remain on the cycles established at surge end. The planned miles shown in the next table fall marginally below the 6,000 required.

Circuit Miles Trimmed

System	Total System	Trimmed			Planned			
		2021	2022	2023	2024	2025	2026	2027
Distribution	28,493	5,021	5,991	4,566				
Subtransmission	2,586	726	723	733				
Total	31,079	5,747	6,714	5,299	3,391	6,150	5,710	5,710

The next table shows that work since 2019 has kept pace with plans, but at an approximate 10 percent increase above expected costs.

Budgeted Versus Actual Trim Miles and Costs

Year	Trim Miles			Cost (millions)		
	Planned	Actual	Variance	Planned	Actual	Variance
2019	4,100	4,187	2%	\$140	\$153	9%
2020	5,500	5,589	2%	\$165	\$179	8%
2021	6,156	5,747	-7%	\$169	\$180	7%
2022	6,300	6,714	7%	\$218	\$251	15%
Total	22,056	22,237	1%	692	763	10%

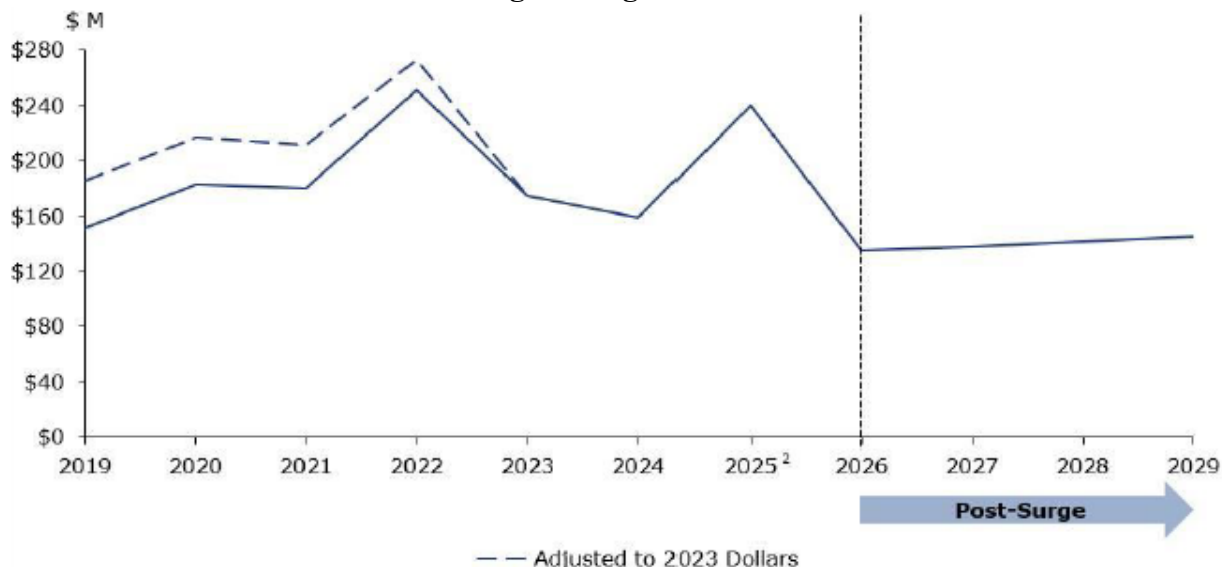
The next table shows that work performed by contractor crews has consistently accounted for more than 95 percent of historic trim costs and essentially all of the variance between budgeted and actual costs.

Tree Trim Cost Drivers

Tree Trim (\$M)	2019		2020		2021		2022	
	Actual	Target	Actual	Target	Actual	Target	Actual	Target
Cost								
ST Labor	\$3.1	\$3.2	\$2.9	\$3.6	\$3.1	\$3.5	\$3.1	\$3.5
OT Labor	\$0.7	\$0.8	\$0.9	\$0.6	\$1.3	\$1.0	\$1.6	\$1.2
Contractor Labor	\$147.2	\$134.9	\$172.4	\$159.3	\$174.4	\$161.6	\$243.9	\$210.8
Materials	\$0.0	\$0.0	\$0.3	\$0.0	\$0.1	\$0.1	\$0.1	\$1.2
Other	\$1.6	\$1.1	\$2.2	\$1.5	\$1.5	\$2.5	\$2.2	\$1.5
Total	\$152.6	\$140.0	\$178.7	\$165.0	\$180.4	\$168.7	\$250.9	\$218.1
<i>Contract Labor %</i>	<i>96%</i>	<i>96%</i>	<i>96%</i>	<i>97%</i>	<i>97%</i>	<i>96%</i>	<i>97%</i>	<i>97%</i>

The next chart illustrates the effects of the surge and the reduction in costs expected to maintain post-surge cycles, with ongoing annual costs of \$135 million per year beginning in 2026.

Post-Surge Change in Annual Costs



Shortening the five-year distribution cycle to a four-year cycle would increase costs. A four-year cycle will require treating an additional 1,400 miles per year, which would produce added annual costs in the range of \$40 to \$50 million. While difficult to calculate, the lesser overgrowth that will occur between treatment on a four-year cycle will serve to reduce that annual incremental cost.

e. Outage Reductions After ETTP Trimming

Management has compared the numbers of outage reductions after ETTP-trimmed circuits to those occurring in the five years before the ETTP trim. This comparison, as the next table summarizes, indicates fewer outage numbers for the first four of the five years that will apply under the going forward five-year distribution trim cycle.

Outage Reductions Following ETTP Trims

Year 1	Year 2	Year 3	Year 4	Year 5
40%	30%	25%	8%	0%

f. Off-Right-of-Way Hazard Trees

DTE removes hazard trees outside rights-of-way where it secures permission. Hazard trees consist of those tall enough to strike a line when falling, and dead, diseased, destructive insect-infected, or structurally weakened trees. The next table summarizes numbers of hazard tree removals and their cost from 2019 through 2022.

Hazard Tree Removals

Year	Number	Cost (in mm)
2019	6,927	\$0.7
2020	4,232	\$1.5
2021	5,696	\$1.2
2022	7,544	\$1.5

2. Conclusions

26. Substantially accelerated forestry cycles have led to significant reliability improvements, with their continuation and potential further acceleration forming a core element of measures that will move reliability cost effectively toward achievement of DGP reliability targets. (See Recommendation #15)

The tree trimming surge combined with an Enhanced Specification for clearance standards has contributed cost effectively to reductions in tree-related interruptions and shorter restoration times during storm recovery. DTE has neared the establishment of improved clearances between limbs and conductors across its system both at the time of the initial pruning and over time as the limbs grow back between cyclical treatment. We found the five-year tree trimming cycle consistent with good practice, but it is not clear that reducing it by another year or so would not add, as others have commonly found, additional reliability benefits on a cost effective basis. While the five-year cycle establishes a sound baseline for now, given the many other needs DTE faces in securing substantial reliability improvements, its plan to examine cycle alterations should remain a priority.

27. DTE’s hazard tree removal practice comports with good utility practice.

The Company’s off-right-of-way hazard tree removal practices contribute to reliability and at moderate cost. Such programs have at other utilities generated sometimes significant owner and public opposition. However, it appears that DTE has adopted measures to ensure owner cooperation. The removal practice should continue until hazard trees no longer cause any subtransmission system outages and minimal distribution system outages.

3. Recommendations

15. Make the planned examination of further adjustments to trim cycles a priority. (See Conclusion #26)

Trees remain a major contributor to SAIDI minutes as the surge in treatment has continued. The shorter cycles and enhanced methods now in place should continue, and, if they do, will continue to make such a contribution. The question that requires examination is whether they can do more at effective cost if shortened for certain areas. DTE plans to study further cycle changes, seeking to optimize the balance between reliability results and the costs to achieve them. Using information gained through controlled analysis of post treatment results and consideration of the unique and incremental impacts of other reliability enhancing measures, management should complete its study of cycle changes as soon as it can.

J. Managing Work Performance

1. Findings

We addressed earlier in this chapter the responsibility of the Director of Distribution Operations Scheduling, Construction, and Tree Trim for scheduling work. The Distribution Operations Scheduling Team, using work management processes, schedules, and, if necessary, adjusts schedules, and ensures that resources are available for the scheduled period. The Scheduling Team works with Regions for DTE workers, with the Logistics Organization for contractor workers, and with the Tree Trim organization for when trim work is required for a job.

Earlier in this chapter we also addressed the responsibility that the Project Management Organization has for capital projects. DTE generally uses contractors under management by this internal organization for work on larger capital projects.

2. Conclusions

28. DTE has dedicated substantial resources to work planning, scheduling, and management; ensuring their operation under best management practices will be essential for ensuring work effectiveness, efficiency, and timeliness. (See Recommendation #16)

The dedication of groups and substantial resources to managing field work planning, scheduling, and management soundly recognizes the pressures that large work levels will bring to effective and efficient work performance. These work levels will directly add to the work required by internal resources to provide sufficient oversight and control. Apart from the direct increase in amount of work to be managed, the need for new outside providers, like installation contractors,

and even large increases in what is expected from existing ones, will present continuing risks in maintaining work effectiveness and efficiency.

3. Recommendations

16. Establish a focused effort for identifying required resources and for closely monitoring program effectiveness and efficiency. (See Conclusion #28)

DTE pays substantial attention to work effectiveness, efficiency, and timeliness, but the more important question at this point is ensuring that such attention recognizes that the future will clearly bring increasing threats to maintaining effectiveness and efficiency in completing the work that the DGP contemplates.

Balancing internal and external resources is critical to getting work done and doing it most economically becomes more challenging when expanded greatly. Creating a management and supervisory structure large and well directed enough to oversee greatly expanded work levels is also critical to managing work timeliness and efficiency. DTE has made significant strides in that respect.

Close monitoring of efficiency will be critical in preventing the stresses that increased work pace places on efficiency to not degrade it substantially. Particularly as reliance on new outside providers or on existing ones called upon to expand their resources on DTE work increases, it will be important to monitor performance metrics.

There is a reasonable prospect that increased work levels will, despite best efforts, prove impracticable to achieve in the DGP's time frame, either at all or without significant degradation of efficiency. DTE will need to ensure that program and project management resources have clear responsibility for performance tracking and systems, methods, and metrics to do so, in order to ensure that leadership has continual, clear, and comprehensive insight into performance drivers that call for efficiency improvement. Management should examine best practices for:

- Empowering, organizing, and staffing program and project management functions
- Comprehensively and quantitatively measuring, analyzing, reporting, and (most importantly) continually assessing improvement methods in performance, by program, location, resource type, and method.

Work types and levels that involved more than average size take correspondingly scoped management. DTE needs to ensure that the efforts it has taken to build up project management organizations are accompanied by measures to continually refine and sharpen its focus and contribution to effectiveness, efficiency, and schedule.

K. System Records

1. Findings

The separate, accompanying report that addresses Part 1 of this engagement described a number of substation records issues found as part of our stratified sampling of facilities in the field. That sampling included a comparison of recorded versus actual field equipment and configurations. That separate report addresses findings with respect to that record/actual comparison.

2. *Conclusions*

29. While not systemic or troubling in terms of managing operations, enhanced control over the accuracy of records of assets in the field is in order. (See Recommendation #17)

Overall, we did not find a lack of conformity between recorded and actual field equipment, but several measures would improve those instances of nonconformity that we did observe.

3. *Recommendations*

17. Adopt as a matter of course several methods for enhancing the consistency between recorded and actual assets in the field. (See Conclusion #29)

These measures should include the following:

- Establish and apply consistently a formal and verified method for identifying and ensuring the entry of pole data changes into GIS records for those replaced as part of emergent pole replacement work
- Enforce the requirement that the Joint Use team continuously update the GIS team with joint attachment data
- Require that, as part of routine inspections and other substation visits, substation operators identify record system mismatches to enable substation engineering to update records.

Chapter II – DGP Reliability Programs

A. Background

This chapter relies upon the findings reported in earlier ones, summarizing information as presented in DTE’s Distribution Grid Plan (“DGP”) and generally following its structure. DTE’s responses to data requests and interviews, which continued through August of 2024, sometimes presented information at variance with details of the DGP, which DTE filed in September 2023. However, we did not find those variances troubling, but instead generally found them small in magnitude or explainable by continuing management thinking and analysis.

Using DGP descriptions and values has the benefit of providing more clear tracking against what remains the most recent consolidated, formal set of widely disseminated plans. However, DTE has continued to update its underlying Reliability Model. Those updates include units and costs of the elements of the principal DGP “Pillars” described below, the programs, measures, and activities that comprise them, and their expected SAIDI, CAIDI, and SAIFI reliability improvements. The results produced by the updates to the Reliability model do not change project reliability improvements substantially (for example, 2028 all-weather SAIDI achievement projects a result of 257 minutes as opposed to the 250 minute value for 2028 presented in the results that support the Company’s March 2024-filled rate case application).

This chapter describes a number of areas where, given reliability as the focus, certain programs addressed in Chapter One of this report and in DTE’s DGP could be slowed without substantially impairing progress toward the Company’s SAIDI goals. Such deferral should not be read as criticizing the programs involved. Chapter One provides our views of their merits and contributions, which extend past reliability improvement. This chapter describes the reliability metrics improvements *as projected* by DTE. It does so recognizing that, while they result from considered and quantitative DTE modeling and calculations, they entail considerable uncertainty, more likely to overstate than to understate expected reliability contributions. Many programs, measures, and activities now have new or greatly expanded scope or frequency. Some circuits and other equipment have experienced overlapping recent application of multiple activities under those changed measures (e.g., expanded vegetation treatment and PTMM work) that have focused on circuit condition and performance prioritization. Factors like these mean that DTE’s base calculations of reliability contribution have sizeable uncertainty overall when extrapolated through 2028. Getting them to accurately isolate individual and incremental reliability improvement by program, measure, and activity also will take significant effort over time.

Despite those qualifications, the Company measures do provide useful perspective on reliability contribution, but judgment remains equally important.

B. Overall DGP Programs, Measures, Activities, and Costs Observations

The preceding chapter of this Part 2 report describes generally the programs, initiatives, and activities that DTE performs to sustain and improve reliability and safety. The preceding chapter made a number of specific recommendations for improvement, but we generally found them typical of those that utilities across the industry apply, albeit with scopes and at paces tailored to their unique circumstances. The principal question becomes one of balancing resources applied to

them in a manner that will optimize reliability and safety performance. The comparatively poor reliability history and current performance levels of DTE complicate the examination of this question. DTE has very far to go in reaching its goal of delivering mid-second quartile reliability performance. The DGP proposes massive investment levels to reach that goal. There is no doubt that large increases from historical expenditure levels will be required to meet the goal by 2028. Converting the many thousands of miles of 4.8kV circuits that will remain after 2028 would dwarf even these large increases the DGP plans.

Our examination did not address the affordability or the value of electricity prices for DTE customers. However, it is clear that the vast size of the programs, measures, and activities the DGP plans have significant implications for those two price factors. Therefore, we did not take DTE reliability improvement targets, the date for achieving them, or the appropriateness of program-specific or total DGP-planned expenditures as given. Balancing reliability improvement with the price impact of achieving them may warrant changes in any or all of them. Therefore, even for programs, measures, and activities that may make material improvements to reliability, we sought to identify those exhibiting the greatest potential for execution at a slower pace.

We also recognized that greatly expanded expenditures will require similar growth in the resources needed to accomplish them, absent very substantial slowing of work pace. DTE is already managing a significant expansion in work from historical levels, producing large overtime levels by internal staff and significantly expanding use of contractors. Further resource growth will add significantly greater pressure on the ability to maintain effective, efficient, and timely performance.

The very large improvement DTE needs to secure in SAIDI performance comprises the second contributing factor. The DGP sets a goal of reducing SAIDI-measured minutes by essentially two thirds. The annual levels of improvement necessary to do so over the short run are extraordinary. Not only that, but closing DTE's great SAIDI gap, as the DGP plans to do, relies on assumptions about reliability improvements from particular programs and measures not yet underlain by enough experience to validate them. DTE projects for some measures (recloser installations for example) only just begun large SAIDI reduction credits.

Very low levels of installations to date and focusing on circuits prioritized by performance levels do not make irrelevant measurement of pre- and post-installation reliability performance on the circuits. However, they do caution strongly against extrapolating results across the system, particularly as diminishing reliability returns inevitably come as installations extend to better performing facilities. Moreover, as DTE acknowledges, work remains to isolate the unique and incremental effects of multiple improvement measures to gain comfort in assessing which contribute most and at least cost. We credit DTE with measurement and with efforts to isolate contribution by individual programs and measures, but we see efforts to take measurements accurately at an early stage.

Thus, whether a five-year push to mid-second quartile SAIDI performance, as opposed to a longer journey to get there, becomes, in our view, an important question to examine. The Commission, informed by stakeholder contribution, clearly must decide the value of mid-second quartile (or any other) SAIDI performance in relation to where electricity prices must go to produce it. The nature

of our engagement, however, does permit a series of observations that we believe can help inform the coming processes for answering that question:

- If mid-second quartile SAIDI performance is considered a DGP planning criterion, then making material reductions to the overall spending levels the DGP proposes are not realistic
- However, even with those levels of expenditures as planned and categorized by the DGP, it is not likely that DTE will achieve its SAIDI goal by the target date selected or shortly thereafter, given the vast SAIDI improvement required
- We do not believe that increasing overall levels of proposed expenditures in an effort to hold to the targeted SAIDI improvement date shows promise, either in terms of making that date or in avoiding significant work effectiveness and efficiency loss.

Establishing a longer duration for achieving mid-second quartile performance will reduce a number of risks presented by the DGP:

- The risks of degradation in work effectiveness and efficiency by reducing stress on the management and field resources needed to execute a massive portfolio of programs, measures, and activities
- The risk of sub-optimizing the balance among reliability-contributing programs, measures, and activities by pacing their execution in a manner that will take advantage of lessons learned from early year efforts and allow a more informed basis for projecting accurately the unique and incremental benefits of a number of overlapping reliability improvement measures
- The risks of failing to integrate with a shorter, five-year plan, a longer-term program for converting all of the many 4.8kV circuits across the system, and of considering the combined effects of that effort which itself is much larger than the already substantial expenditures of the DGP, which leaves that even much larger challenge unaddressed.

We view this last factor as a particularly important one. DTE's aspirational goal is to complete 4.8kV conversion by 2040, at an expected cost as high as \$25 billion. The high levels of uncertainty attendant upon preliminary estimates of megaprojects make it wise not to view even that number as a ceiling. However, even forgetting that risk, future 4.8kV conversion costs alone would fall into a range of \$2 billion or more per year, and it will come on top of whatever other needs the system will inevitably continue to face, even if not required to respond to the higher weather and electrification scenarios postulated. States that have restructured their electricity industries leave to competitive energy markets the role of setting pricing for energy production, leaving their utilities to deal with its delivery. Those markets thus price much of what needs to be done to meet decarbonization and other goals that concern energy production. Here, however, the Commission's responsibilities extend to both production and delivery. To the extent that the state's energy goals may have a significant impact on energy prices, they will add to the need for addressing electricity affordability and value.

These factors add to the merits of assessing reliability improvement and its timing and costs, not just or even predominantly in the context of the DGP's planning horizon, but with reference to the large question about long-term 4.8kV conversion and how energy pricing will change. Treating decarbonizing as fixed, it becomes clear that reliability and factors like 4.8kV conversion become

the moving part in efforts to create an electric price path that responds both to affordability and to value.

The following sections of this chapter provide observations about potential changes in the distribution of investments under the DGP, whether to better focus on reliability performance or to indicate where slower paced investments appear most supportable under the addition of a longer planning horizon for use in assessing consistency with the DGP’s five-year view. As the previous chapter noted, we did not find problems with the existence of the programs, measures, and activities the DGP proposes. We found material adjustment appropriate for several. For the remainder, the central issue this chapter addresses is the identification of those that may lend themselves to longer completion durations or slower cycles.

C. DGP Summary

1. Plan Goals and Pillars

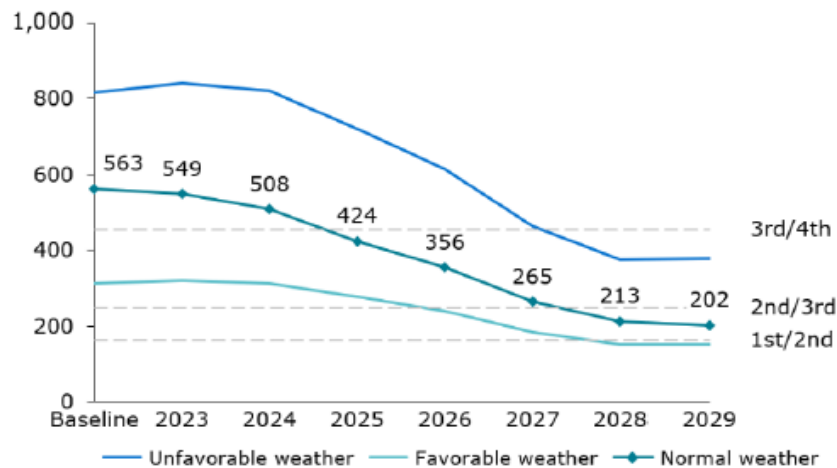
The DTE DGP sets three primary goals:

- Increased reliability and resilience during extreme weather
- Accelerated response to customer outages with faster power restorations, identification and de-energization of downed wires, and accurate estimates of service restoration times
- Increased capacity to meet current and future energy needs.

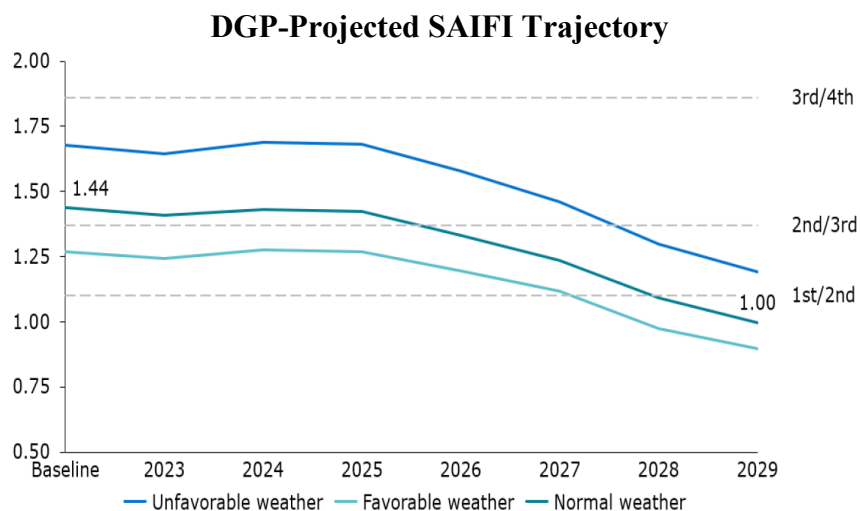
DTE projects that accomplishing the DGP plan will by 2029 produce (as the following chart illustrates):

- Mid-second quartile all-weather SAIDI performance in normal weather² performance, improving by 64 percent
- A smaller difference between SAIDI in favorable versus unfavorable weather
- First quartile all-weather SAIFI during normal weather quartile performance, improving by 27 percent.

DGP-Projected SAIDI Trajectory



² Normal weather year typically has a quantity of Major Event Days (MEDs) that is close or equal to the average of the last ten years.



The DGP cites aging infrastructure, whose effects worsening weather exacerbates, and capacity constraints as major needs for ensuring and improving reliability. The DGP cites specifically the 60 to 80 year age of its 4.8 kV distribution facilities, and 50 to 60 years for portions of the 13.2kV system. The DGP reports loading constraints on a third of distribution substations, either at the substation level or on the circuits they serve. DTE currently operates 783 substations, which include about 1,600 transformers and 6,000 breakers. Those substations serve about 45,000 miles of subtransmission and distribution lines, 31,000 overhead and 14,500 underground. DTE operates about 450,000 pole-mounted or padmount distribution transformers near service locations.

The DGP describes three principal focuses through 2028:

- System stabilization through hardening programs that seek to eliminate outages
- Reduced outage scopes and durations through the addition of 10,000 reclosers that will increase automation of restorations
- Replacement of end-of-life equipment with current technology to continue grid modernization through substation and circuit voltage conversions and subtransmission upgrades to improve reliability by installing the latest automation technology, which will improve safety by eliminating energized wire downs, and adding capacity for DER and electrification.

The DGP sets forth four work “pillars” that organize the investments and activities specifically proposed to carry out these work focuses:

- **Tree Trimming:** with two-thirds of outage time resulting from tree contacts historically, the DGP proposes to continue its ramp up of tree trimming to bring all overhead circuit wires under a five-year cycle by 2025
- **Infrastructure Resilience and Hardening:** a three-part effort that consists of: (a) expanding the PTMM to bring within a ten year cycle the testing of pole and pole-top equipment condition, replacing failed components with stronger equipment designed to higher standards, (b) completing in 2026 the Detroit 4.8kV hardening program for replacing (with upgraded facilities in many cases) all poles and pole-top equipment that

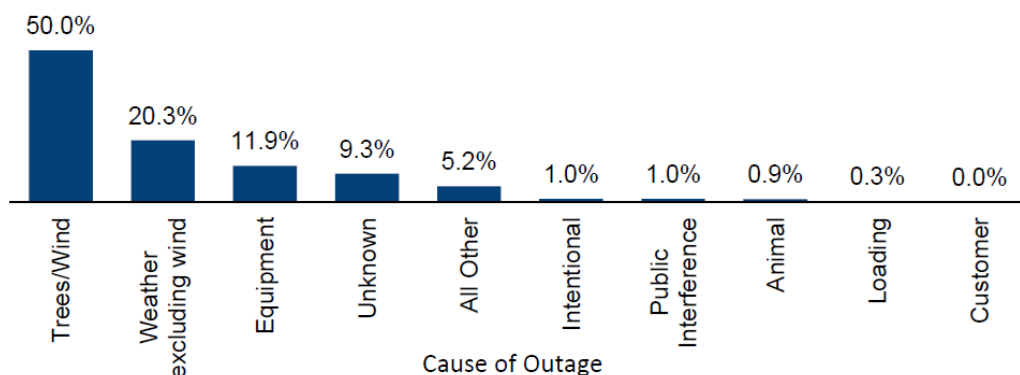
fail inspection and for removing abandoned city arc wire once used by the Detroit Public Lighting Department, and (c) programmatic overhead, underground, and substation equipment replacement

- **Infrastructure Redesign and Modernization:** increasing capacity on overloaded portions of the legacy distribution and subtransmission systems, converting the 4.8kV ungrounded system to 13.2kV for safety and capacity reasons, and analysis of converting overhead lines to underground facilities
- **Technology and Automation:** Full automation of the distribution grid by the end of 2028, grid communications, operational technology, and information technology upgrades and support.

2. Reliability Performance Drivers

The DGP acknowledges largely fourth quarter all-weather (*i.e.*, including the impacts of MEDs) performance under SAIDI and CAIDI and second and third quartile performance for SAIFI performance since 2014. The next table shows its assignment of outage minutes measured using SAIDI for the most recent five years. The table shows trees and wind as the directly assigned cause of half of them. Commonly, some portion of equipment outages have tree contact as a contributing cause and a portion of Unknown outages also typically result from vegetation as well. Those categories account for another 21 percent as attributed by DTE.

Five-Year SAIDI Minutes by Outage Cause



The DGP makes clear that DTE considers asset age a material measure of reliability performance, citing industry benchmarks and manufacturer recommendations. The next table summarizes ages for the 18 asset classes that DTE identifies as having the greatest impact on reliability. We do not find the average ages listed abnormal overall in our experience. We did find portions of some in-service assets older than usual, including some subtransmission and system cables, oil circuit breakers, and manholes. We also have not found manufacturers’ recommendations or industry benchmarks as controlling in determining when to replace assets. Asset condition determined by inspection and testing and the performance appropriate to each asset type should drive replacement. The ability to secure replacement parts and escalating costs to maintain equipment can prove contributing factors, but age alone in our view should not. Finally, nothing found in our field inspections of poles and pole tops and substations identified repetitive condition abnormalities or condition issues for those assets more pronounced due to age.

Ages by Asset Group

Asset	Age		Life Expectancy	
	Range	Average	Years	%>
Substation Transformers	0 - 99	43	40 - 45	49%
Network Bank Transformers	0 - 85+	46	20 - 30	91%
Circuit Breakers	0 - 90	41	30 - 40	60%
Circuit Switchers	0 - 36	19	NA	NA
Relays	0-60+	33	15 - 50	NA
Switchgear	0 - 70	40	40	55%
Poles	0 - 90+	46	40 - 50	50%
Three-phase Reclosers	0 - 34	10	20	10%
SCADA Pole Top Switches	0 - 31	15	20	38.5%
40 kV Auto. Pole Switches	0 - 50+	21	40	35%
Overhead Capacitors	Oldest: 25+	NA	20	NA
Overhead Regulators	Oldest: 25+	NA	20	NA
System Cable	0 - 100+	49	20 - 40	64%
URD Cable	0 - 60+	26	40	23.6%
Manholes	1 - 100+	78	Varies	NA
(AMI meters)	0 - 13	6.5	20	0%

The DGP summarizes a number of asset grouping circumstances and conditions, including:

- Poles and Pole-Top Equipment: data about these two asset groups, which comprise large investment sources under the DGP
- Substation Transformers: Removal of an average of 15 substation transformers (with an average age of 48 years) per year over the last five years on the basis of failure imminence or actuality
- Circuit Breakers: 53 percent of the system’s 6,000 circuit breakers identified as replacement candidates based on health assessment, with oil-filled breakers comprising two thirds of the replacement candidates, and commonly scheduled in the industry for programmatic, paced replacement
- Three-Phase Reclosers: Currently installed on 5.5 percent of DTE’s distribution circuits, DGP plans call for continuation of their use to loop new and converted circuits, automate portions of the 4.8 kV system where possible, and replace and repair those that fail or do not pass inspection
- System Cable: DTE has identified 28 percent of its subtransmission and distribution underground system cable as being at high-risk of failure
- URD Cable: DTE lists all 23.6 of URD cable percent beyond its life expectancy range as “ready for replacement”
- Small Wire: As it performs work occasioned by other circumstances, such as load growth and conversion projects, DTE replaces small-gauge wire that it no longer employs in new installations because its lesser current carrying capacity and strength increase breakage risk on tree contact.

3. Capital Investments

DTE reports grid investments of \$5 billion in the preceding five years and a total of \$5.8 billion in “strategic capital” and nearly \$600 million in forestry across the planning horizon of the DGP. The

next table summarizes DGP planned capital investments, whose total extends well past the strategic capital programs that focus on sustaining and improving reliability and on which we focused.

DGP Grid Plan Investments

Category		Capital Investments (\$ Millions)					
		2024	2025	2026	2027	2028	5-Year Total
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	\$415	\$399	\$368	\$348	\$345	\$1,877
	Customer Connections, Relocations and Others	\$282	\$295	\$314	\$334	\$355	\$1,580
Strategic Capital Programs (details in Exhibit 6.1.2)		\$906	\$995	\$1,134	\$1,302	\$1,485	\$5,821
Total Capital Investments		\$1,603	\$1,689	\$1,816	\$1,985	\$2,185	\$9,278

Strategic Capital Program Summary

Pillar	5-Year Pillar Investment 2024–2028 (Millions)	Largest Investment Area	5-Year Program Investment 2024-2028 (Millions)
Tree Trimming	\$573	Enhanced Tree Trimming Program	\$573
Infrastructure Resilience and Hardening	\$1,639	Pole and Pole Top Maintenance and Modernization	\$773
Infrastructure Redesign and Modernization	\$2,537	4.8kV Conversion and Consolidation (including CODI)	\$1,498
Technology and Automation	\$1,645	Grid Automation	\$1,192

4. DTE’s Reliability Model

DTE has produced revised model inputs (units and costs) to the numbers represented in its DGP for some of the programs that this chapter addresses. These revised numbers also produce revised estimates of reliability impacts over the 2024 through 2028 period. Information provided by DTE focused on the areas of its DGP that would drive reliability metrics improvements and therefore addresses a subset of the total expenditures originally proposed by the DGP - - \$3.692 billion of the DGP’s \$9.278 billion in proposed capital expenditures plus an additional \$573 million in O&M expenses for tree trimming. The next table compares DGP values in areas that the model addresses to the values that DTE has reported as reflected in a recent version of the model.

Revised Reliability Model Cost Assumptions

<i>Grid Plan</i>							
Pillar	Program	2024	2025	2026	2027	2028	Total
1	Tree Trim	\$123	\$140	\$101	\$103	\$106	\$573
2	4.8kV Hardening	\$80	\$95	\$54			\$229
3	Conversion	\$171	\$202	\$343	\$372	\$410	\$1,498
2	PTMM	\$121	\$121	\$151	\$192	\$188	\$773
4	Automation	\$62	\$163	\$191	\$309	\$469	\$1,192
Total		\$557	\$721	\$840	\$976	\$1,173	\$4,265
<i>Reliability Model</i>							
Pillar	Program	2024	2025	2026	2027	2028	Total
1	Tree Trim	\$159	\$240	\$135	\$138	\$142	\$814
2	4.8kV Hardening	\$80	\$125	\$54			\$259
3	Conversion	\$229	\$246	\$238	\$305	\$349	\$1,367
2	PTMM	\$64	\$121	\$141	\$210	\$269	\$805
4	Automation	\$40	\$150	\$228	\$293	\$284	\$995
Total		\$572	\$882	\$796	\$946	\$1,044	\$4,240
<i>Model Increases and (Decreases)</i>							
Pillar	Program	2024	2025	2026	2027	2028	Total
1	Tree Trim	\$36	\$100	\$34	\$35	\$36	\$241
2	4.8kV Hardening	\$0	\$30	\$0	\$0	\$0	\$30
3	Conversion	\$58	\$44	-\$105	-\$67	-\$61	-\$131
2	PTMM	-\$57	\$0	-\$10	\$18	\$81	\$32
4	Automation	-\$22	-\$13	\$37	-\$16	-\$185	-\$197
Total		\$16	\$161	-\$44	-\$29	-\$129	-\$25

dollars in millions

The revised inputs include a reduction of \$25 million, or 0.6 percent, of proposed DGP amounts for comparable programs. Changes in individual programs include:

- Tree trim: an increase of \$241 million or 42.1 percent³
- 4.8kV Hardening: an increase of \$30 million or 13.1 percent, all of it assigned to 2025
- Conversion: a reduction of \$131 million, or 8.7 percent
- PTMM: an increase of \$32 million, or 4.1 percent
- Automation: a decrease of \$197 million, or 16.69 percent.⁴

The results produced by the updates to the Reliability model do not change projected reliability improvements substantially. For example, 2028 all-weather SAIDI achievement projects a result of 257 minutes as opposed to the 250 minute value for 2028 all-weather SAIDI presented in the results that support the Company’s March 2024-filed rate case application.

³ DTE reports that the Tree Trim values from its DGP are in error.

⁴ It appears that the reliability model treats as Automation most (\$1.192 billion) but not all (\$1.356 billion) that the DGP assigns to Grid Automation.

Reliability Model Projected Metrics Results

All Weather						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	503	482	412	354	257	186
SAIFI	1.30	1.31	1.24	1.18	1.04	0.92
CAIDI	386	367	333	301	247	202
Excluding MEDs						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	160	160	148	138	115	97
SAIFI	1.00	1.02	0.96	0.91	0.79	0.69
CAIDI	159	158	154	151	145	139

The following tables show the modeled projected results for the five programs described earlier. Note that the program-specific results included in these numbers add to a total that exceeds the results summarized in the previous table. This results from DTE’s attempts to show only the projected system benefits of each program individually; the previous table attempts to account for any “double counting” of benefits from multiple programs.

Reliability Model Projected

All-Weather SAIDI Minute Reductions Through 2028

Program	Minutes	% of Total
Automation	225	47%
Tree Trim	125	26%
PTMM	83	17%
4.8kV Conversion	36	7%
4.8kV Hardening	11	2%
Total	480	100%

Reliability Model Tree Trim Program Improvements

All Weather						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	14	42	69	94	125	154
SAIFI	0.02	0.05	0.09	0.14	0.17	0.22
CAIDI	6	15	23	28	38	43
Excluding MEDs						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	3	10	18	26	33	40
SAIFI	0.01	0.04	0.07	0.11	0.14	0.16
CAIDI	1	3	5	8	9	10

Reliability Model 4.8kV Hardening Program Improvements

All Weather						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	1	6	9	11	11	12
SAIFI	0.00	0.01	0.02	0.02	0.03	0.05
CAIDI	0	1	1	1	1	-2
Excluding MEDs						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	0	2	3	3	3	3
SAIFI	0.00	0.01	0.02	0.02	0.02	0.02
CAIDI	0	0	0	0	0	0

Reliability Model PTMM Program Improvements

All Weather						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	3	13	28	49	83	131
SAIFI	0.01	0.03	0.07	0.14	0.22	0.36
CAIDI	0	0	0	-1	2	4
Excluding MEDs						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	1	3	7	14	22	34
SAIFI	0.01	0.03	0.06	0.11	0.17	0.27
CAIDI	0	-1	-2	-3	-5	-7

Reliability Model Automation Program Improvements

All Weather						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	0	10	74	121	225	310
SAIFI	0.00	0.01	0.12	0.20	0.38	0.55
CAIDI	0	4	20	32	61	81
Excluding MEDs						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	0	3	19	34	64	88
SAIFI	0.00	0.01	0.09	0.16	0.30	0.42
CAIDI	0	1	4	7	14	19

Reliability Model 4.8kV Conversion Program Improvements

All Weather						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	1	3	8	19	36	67
SAIFI	0.00	0.01	0.02	0.05	0.09	0.17
CAIDI	0	0	0	0	3	4
Excluding MEDs						
Metric	2024	2025	2026	2027	2028	2029
SAIDI	0	1	2	5	10	17
SAIFI	0.00	0.00	0.02	0.04	0.07	0.12
CAIDI	0	0	0	-1	-1	-2

5. *Conclusions*

1. Closing the SAIDI gap that DTE proposes to reach through DGP programs, measures, and activities is too aggressive. (See Recommendation #1)

DTE must close an extremely-large SAIDI gap to reach mid-second quartile performance. It must make extraordinarily high expenditures to get there under its DGP and its Reliability Model. Very large uncertainties surround DTE's measurements of expected reliability improvements by program, measure, and activity. These combinations make reaching that elevated level of reliability performance for the amounts planned questionable.

Achieving mid-second quartile reliability outage duration performance and first quartile outage frequency performance would place DTE well into levels of performance properly considered as strong. However, the outage minutes it must eliminate and the amounts it will have to spend to get there make it more appropriate to set a longer term course to reach these goals, unless policy or other considerations compel the closing of this great gap on the current planned schedule.

Already high enough to have significant electricity pricing impacts, it will likely take more work and thus even higher costs to achieve the reliability results forecasted. Moreover, there is risk of cost increase given the stress on resources that such large work levels will impose both on management and on the resources, largely contractors, needed in the field. DTE has recently moved to enhance its project management organization, resources, and methods, but even continuing to embed and enhance them will not likely avoid higher unit costs.

Apart from improving reliability, DTE must undertake significant expansions to address safety issues with its ungrounded 4.8kV system and bring several inspection and maintenance cycles and backlogged work levels into conformity with common industry practice. Its installation of reclosers on the 4.8kV system dedicates some to substation exit points, which will address energized down wire concerns on its delta-configured circuits, and some to other locations where the reclosers will generate reliability improvements. Not placing higher priority on installing the devices at those substation exit points will leave larger safety risks for longer durations. Completing the safety-driven installations as promptly as practicable, which we believe is appropriate, will leave fewer allocated to reliability improvement, absent further expenditures to compensate. The reliability impacts of shifting DTE's planned allocation of reclosers for safety, as opposed to reliability reasons, does not present a suitable justification for not giving primary emphasis to measures necessary to mitigate the risks of customer harm from downed wires. The predominance of ungrounded 4.8kV circuits on its system is extraordinary.

Perhaps most significantly here, the DGP cites but does not address the planning consequences of meeting its aspirational goal of converting all of its 4.8kV circuits by 2040, or about 12 years after the horizon the DGP addresses. With the \$25 billion amount forecasted as of now (an amount that may prove larger, given the reliability of preliminary estimates for megaprojects) it does not appear realistic to assess plans through 2028 without addressing a program whose amounts through 2040, even before addressing other needs over that period, dwarf DGP investment levels.

2. The DGP shows a directionally correct relationship between reliability improvement and emergent work, whose costs are projected to fall as system improvements reduce outage

levels, but the costs for such work still represent a high proportion of investments. *(See Recommendation #2)*

Capital expenditures for emergent work have trended downward in the last few years, as more frequent tree trimming cycles and other programmatic work have expanded, but still comprise a high percentage of all capital expenditures, suggesting value in examining the future path of those expenditures over the DGP horizon and following.

6. Recommendations

- 1. Restate DGP reliability and safety program, measure, and activity scopes to optimize scope and expenditures assuming an extended period to reach mid-second quartile SAIDI to performance and to reflect a range of approaches regarding full-scale 4.8kV conversion.** *(See Conclusion #1)*

A ten-year period to reach mid-second quartile SAIDI reliability performance is more realistic in terms of the time it will take to close the reliability gap that now exists and in terms of avoiding both cost inefficiency and better directing efforts to achieve it at least cost. Doing so will allow for more informed decisions about the value of improved reliability by illustrating the costs of achieving it more or less rapidly. Moreover, planning decisions about full-scale 4.8kV conversion, particularly its timing, should move past aspiration and to concrete addressing to further inform consideration of electricity service affordability and value. Doing so may not inform decisions about decarbonization, taking them as a given. However, taking them as a given makes grid reliability and safety the principal variable to adjust to meet any need to create a total electricity price path that is sustainable. This factor as well warrants a 10-year view of the journey to strong reliability performance informed as well by the great impact that full-scale 4.8kV conversion may have, not to mention the other system needs that will have to be met through that conversion process.

- 2. Examine estimates of forecasted emergent work costs for consistency with expected reliability improvements and revise them as necessary.** *(See Conclusion #2)*

The magnitude of capital costs for emergent work warrants a careful review of how attuned their forecasts are to DGP programs, measures, and activities to improve reliability and their consequent impacts on outage frequency and system and customer impacts.

D. Pillar 1: Tree Trimming

1. Background

The DGP's assignment of tree trimming alone to one of the four major work "pillars" reflects the unique and large importance it has for sustaining reliable grid performance. Tree contacts with overhead power lines, especially during adverse weather conditions, are a leading cause of DTE's power outages. DTE has already ramped up tree trimming work from 2019 through 2022, using about 1,200 personnel, spending more than \$800 million, and trimming about 80 percent of system overhead miles since 2019. The DGP sets a goal of "surging" trimming efforts to complete 31,000 system overhead miles by 2025 and continuing to trim on five-year cycles thereafter. The Company has also adopted an Enhanced Tree Trimming Program ("ETTP") that sets revised specifications for forestry work. Measures to enhance tree clearing effectiveness include the use

of new and specialty equipment in areas, such as alleyways, that present access difficulties. In addition, after bringing distribution overhead circuits in line with a five-year cycle, and subtransmission overhead circuits in-line with a three-year cycle, management plans to use modeling supported by Light Detection and Ranging and other data to set optimum cycles for individual circuits based on their unique circumstances. DTE has also been conducting two pilot programs designed to increase trained local resources to offset the need for non-local crews that the increased forestry work of shortened cycles and surges to get work onto them have produced.

2. *DGP Measures*

The DGP proposed a 2024 through 2028 total of \$573 million for Tree Trimming. As reflected in recent updating of its Reliability Model, DTE now assigns a significantly greater \$814 million to Tree Trimming, now producing an estimated all-weather SAIDI improvement of 125 minutes through 2028. DTE views this model as capturing all DGP programs, measures, and activities having a material impact on SAIDI improvement.

3. *Conclusions*

3. The shortening of forestry cycles and the enhancement of trimming and clearing methods comprise core and highly effective elements of DGP plans for sustaining and improving reliability, with continuing efforts by DTE seeking to further optimize cycles. (See Recommendation #3)

The methods and cycles that DTE has adopted will soon move to a sustaining mode, as it nears the end of the period during which it has “surged” expenditures to bring the entire system into compliance. DTE remains engaged on tailoring cycles to particular locations, surrounding vegetation populations and conditions, and circuit or segment groupings. Continuation of those efforts should further align work levels with reliability benefits versus the costs of obtaining them.

Others have found that sustaining forestry cycles after completion of the first, substantially shortened cycle, produces large cost savings. The overgrowth that complicates work on the first cycle no longer exists with the more frequent subsequent visits involved. This phenomenon, as DTE completes its surge, may have a material downward impact on future costs through and past the DGP horizon.

4. *Recommendations*

3. Continue the current forestry methods and cycles, tuning and adjusting them as warranted by continuing evaluations of their costs and benefits and adjusting forecasted Tree Trimming expenditures as work continues into the next cycle(s). (See Conclusion #3)

The changes made and the approaching completion of surge work have brought DTE methods and practices into general conformity with good utility practice, and have had, and will continue to have, material benefits to sustaining and to improving reliability. Expanding information about results of the application of new methods and cycles for the first time to the entire system will provide insights useful in determining where adjustments can be made on locational, vegetation surroundings, and circuit condition basis. Continuation of DTE’s examination of such fine tuning is important. Equally important is prompt adjustment to ongoing expenditure requirements to

ensure that forecasts and in turn budgets for Tree Trimming fully reflect the diminished work requirements for maintaining cycles.

E. Pillar Two: Infrastructure Resilience and Hardening

1. Background

The work in this second pillar addresses the replacement and upgrading of aging infrastructure (e.g., poles, crossarms, transformers and substation equipment) to secure near-term grid reliability and resiliency improvement. Its programs include:

- The PTMM program
- 4.8kV Hardening
- Overhead Equipment Replacement
- Underground Equipment Replacement
- Substation Equipment Replacement
- Major Event Risks
- Poor Reliability Circuits.

2. DGP Measures

a. PTMM Program

DTE strongly emphasizes the importance of its PTMM program, listing it first among its “Top 50 Strategic Capital Programs and Projects.” DTE reports that overhead equipment failures cause about one quarter of its customer outages. This program has operated on the basis of performing visual inspections of overhead circuit poles and pole tops on a roughly 20-year cycle and pole strength testing on poles in excess of 20 years of age. The PTMM comprises the only cyclical pole and pole-top inspection program that DTE performs, apart from 4.8kV Hardening, described below. It is customary for utilities to conduct two separately-cycled inspection and testing programs:

- Overhead Circuit Inspections of poles and pole top equipment on fairly short cycles (e.g., two-to-five years) designed to address poles and equipment at risk of failure prior to the next cycled visit
- Pole Strength Testing on longer cycles (e.g., 10- to 15-years) for older poles (e.g., 20+ years of age).

DTE also plans to bring subtransmission overhead circuits on-cycle under the PTMM program. DTE’s benchmarking has also demonstrated four-to-five year visual inspection cycles as typical. A 20-to-30 year cycle is well outside the range of good practice. DTE has occasion to “get eyes on” circuits for other reasons. However, as Chapter One explained, even with those instances, DTE does not come close to producing a four or five year duration between visits, and they involve different purposes and time pressures.

The scope of the PTMM Program includes testing pole strength and inspecting pole-top equipment to determine condition. The program calls for replacement of poles that fail testing and deteriorated pole-top equipment, using equipment designed to the higher standards currently applicable. As with forestry, DTE plans for the application of a firm cycle, 10 years in the case of PTMM, for

inspections that will drive these replacements. The DGP notes that overhead equipment failure reportedly causes about 25 percent of outages. DTE has established specifications for major pole-top components for use when performing inspections that produce PTMM work. They call for:

- Fiberglass Crossarms, which have five times greater strength and 60-year life spans
- Polymer Bolt Down Insulators, which have six times greater strength and are longer lasting
- Polymer Cut-outs (combining fusing and switching to provide power surge protection), that are also six times greater in strength and are longer lasting.

Under the PTMM Program, DTE addressed 1,562 circuit miles and replaced 4,537 poles in 2022, for an average of 2.9 pole replacements per mile. DTE anticipated 1,000 circuit miles and replacement of approximately 3,300 poles (including a pre-2022 backlog of condemned poles) for an average of 3.3.

DTE’s DGP reports plans to spend \$773 million combined on PTMM and 4.8kV hardening from 2024 through 2028, as the next table summarizes. The cost entries through 2026 do not separate amounts for the two programs. The 4.8kV Hardening program is planned for completion in 2026. The roughly \$190 million DTE anticipates for each of 2027 and 2028 thus appear to reflect the annual costs of sustaining a 10-year cycle. We do not consider it likely that the annual costs would remain that high thereafter, under a program that prioritizes work on the basis of sectors and circuits deemed worse performing.

DGP PTMM Summary

Item	2024	2025	2026	2027	2028	Total
PTMM Investment (in millions)	\$121	\$121	\$151	\$192	\$188	\$773
Miles Inspected	1,604	1,604	2,043	2,651	2,651	10,553
\$/mile	\$75,436	\$75,436	\$73,911	\$72,425	\$70,917	\$73,249

Data from a recent DTE Reliability Model included updated proposed PTMM investment values of \$805 million, an increase of \$32 million, or four percent above the \$773 million shown in the table above. Even more recently-provided data for 2027 and 2028 show 2028 generating a number of miles consistent with a 10-year PTMM cycle. This update also shows that costs per mile have increased by about 20 percent from the DGP numbers. The latest data shows an increase from \$192 million in the table above to \$210 million for 2027 and from \$188 million to \$269 million for 2028. This latest data conforms to DTE’s observation that recent experience with the numbers of equipment rejections are higher than expected, thus driving a corresponding increase in forecasted investments.

Most Recently Provided PTMM Miles and Costs

Year	Source	Miles	Δ	\$/mile	\$/mile	Δ
2027	DGP	2,651	-9%	\$192	\$72,425	21%
	Update	2,400		\$210	\$87,500	
2028	DGP	2,651	21%	\$188	\$70,917	19%
	Update	3,200		\$269	\$84,063	

The DGP cites enhanced PTMM inspections as producing a doubling or tripling of poles per mile that fail inspection and identifying locations warranting pole-top equipment work. With growth in inspections only a year old, DTE lacks performance information from which to project the reliability improvements that expanded treatment and replacement will produce. The goal calls for reaching in 2028 a 10-year PTMM inspection and treatment cycle that includes visual inspection of all poles and physical inspection of those in excess of 20 years.

DTE estimates that multiple customer outage events will fall by 30 percent in the first year following PTMM inspection and replacement activities. The Company bases this estimate on experience with its Customer Excellence program for addressing circuit segments whose customers experience particularly poor performance and with 4.8kV conversion work. Using work on particularly poor performing circuits makes this estimate of improvement from PTMM work overly optimistic for application across the system. Moreover, as noted, DTE precedes PTMM work with tree clearing activities. Therefore, the circuit performance improvement in the first year following PTMM work also includes the benefits of tree clearing. The commonality of clearing and PTMM work illustrates the complexity in assigning reliability improvements among multiple activities that contributed. Nevertheless, the need for regular visual inspections on a reasonably short cycle, critical to maintaining reliability for all companies, has particular importance for DTE. PTMM work in 2022 addressed 1,562 circuit miles, implying a cycle of about 20 years. The 1,000 miles planned for 2023 better reflect a cycle of 30 years.

DTE has undertaken efforts to isolate the impacts of particular elements of its measures to address reliability. One, for example, compares the results of enhanced tree trimming on circuits so treated and a control group not so treated. The analysis compares tree-related outage and wire down event numbers and numbers of customers interrupted and minutes of interruption. The comparison used an average of performance in these four categories for three years preceding enhanced trimming with performance in the same four categories in each of the four years following enhanced trimming.

The use of such analysis is sound, but can produce over-reliance on given factors such as:

- The need to account for other than forestry having impact on the factors measured
- Results from work on high priority, worse performing circuits cannot be extrapolated to larger circuit populations without sometimes substantial discounting
- Weather variability between the pre-and post-enhanced treatment durations can mask the contribution of the work performed.

Discussion of such factors in a group session with broad management participation underscored the importance of such variables. Similarly here, measuring the individual impact of Infrastructure Resilience and Hardening measures on circuits with varying last vegetation treatment dates can prove problematic.

The DGP cited a 2023 American Society of Civil Engineering report rating Michigan infrastructure at a cumulative C- grade considering categories including, for example, bridges, roads, and schools. The state as a whole received an even lower D grade for energy infrastructure. A review of that report found its treatment of energy very broad, covering energy sources not limited to those that generate electricity, and dealing more explicitly with ISOs and transmission, and

including among its references little that appears material in assessing the quality of DTE distribution grid infrastructure either generally or with respect to system configurations or equipment and other asset types. We did not find it helpful in assessing areas where the DTE distribution grid may be in need of reinforcement, rebuilding, or upgrading.

b. 4.8kV Hardening

This second Infrastructure Resilience and Hardening pillar also includes finishing in 2026 the already well-advanced Detroit 4.8kV Hardening Program. The DGP proposed \$229 million to complete the program in 2026. The latest version of the Reliability Model increases this number to \$259 million. Wires down performance, SAIFI, and SAIDI all show very substantial improvement after hardening.

Work between 2018 and 2023 has already hardened somewhat more than half of the program's 1,464 miles. This program addresses the oldest part of DTE's distribution network, whose facilities reportedly experience more than three times the trouble rate of circuits outside the city. When it produces cross arm and insulator replacement, 4.8 kV hardening uses materials and equipment suitable for eventual conversion to 13.2 kV. Concluding this program will complete the replacement of all poles that fail inspection and defective pole-top equipment on the city's remaining 589 miles under the program. Incorporating the elimination of no longer used municipal arc wire collocated with DTE's 4.8kV facilities in Detroit followed a Commission order in Case No. U-18484 addressing such arc wire. Arc wire lengths of about 1,400 miles are substantially coincident with the 4.8kV circuits the hardening program encompasses. The work performed under the 4.8kV hardening program includes:

- Tree trimming required to permit work on the circuits
- Removing of arc and distribution wire from Company-owned equipment, leaving remaining wires safely configured
- Testing poles carrying Company equipment, followed by reinforcement or replacement of damaged or deteriorated equipment, as needed
- Removing service lines to abandoned properties
- Removing primary conductor (deconductoring) in sparsely populated areas.

c. System Equipment Replacement

Asset health analysis informs DTE's prioritization of equipment replacement program investments and identification of the equipment that requires replacement. The DGP describes plans to invest \$365 million through 2028 for replacement of equipment in categories covering overhead, underground, and substation equipment. The Reliability Model, which management reported as addressing the programs with substantial reliability impacts, does not appear to assign any improved metrics performance to this category of expenditures.

The System Equipment category includes:

- Overhead
 - \$27.3 million for 69 subtransmission circuit sectionalizing Automatic Pole-Top Switches ("APTSS") identified as requiring replacement

- \$13.9 million for 154 units of two Supervisory Control and Data Acquisition (“SCADA”) equipment types subject to high failure rates
- \$25 million for 53 wood- to-steel pole highway crossing conversions to reduce risk of collapse
- Underground
 - \$101.5 million for 85 miles of primary system cable that asset health assessments have identified as replacement candidates (28 percent of the system’s 2,050 miles)
 - \$75 million for replacing 320 miles of Underground Residential Development (“URD”) cable of a type that has caused both DTE and the industry significant problems due to high failure rates (approximately 1,000 per year at DTE)
- Substation
 - \$74.3 million for 167 asset health-based replacements of circuit breakers that isolate faults to interrupt current flow after fault detection to minimize equipment damage and to isolate the faulted asset from the system (DTE has identified 53 percent of the system’s 6,000 breakers as replacement candidates)
 - \$4.2 million for 15 replacements of Substation Regulators that keep voltages within a normal range
 - \$15.0 million for 103 replacements of Subtransmission Disconnect Switches that manually sectionalize and isolate system points for operations or maintenance purposes to reduce safety hazards, enhance system operability, and reduce the need for taking equipment out of service to allow work
 - \$9.5 million for 30 replacements prioritized by failure risk and inadequate sizing of circuit switches connecting the transmission and subtransmission systems protecting substation equipment from excess fault current caused damage
 - \$14.6 million for 386 end-of-life-based replacements of Battery and Charger equipment providing power needed to trip equipment during fault conditions to reduce outage size and duration, equipment damages, and safety hazards.

d. Poor Reliability Circuits

Two programs provide out-of-cycle maintenance and repair programs addressing circuits with poor reliability. Between normal inspection and maintenance cycles, the Customer Excellence (“CE”), and Frequent Outage (“CEMI”) programs address pockets of customers experiencing poor reliability. The Company has indicated that investments of \$283 million for 2024 through 2028 are planned to exceed expenditures of the prior five years by \$88 million, or 45 percent.

DTE targets customers experiencing four sustained outages or nine momentary outages per year. Additional factors prioritize circuits for treatment under the program. Measures to address these pockets under the CE program, which generally require investments of \$60,000 to \$80,000 per circuit include, for example, equipment replacement, tree trimming, equipment checks to verify proper operation, fault studies to validate fuse sizing, reclosing devices and animal guards, to prevent future outages. Similar in purpose and activities, CEMI uses longer, three-year average SAIDI and SAIFI values to identify work areas, which may extend beyond pockets of customers to entire circuits. Its more extensive scope and comprehensiveness make its cost more on the order

of \$250,000 to \$300,000 per circuit. DTE anticipates that program investment levels will decline as DGP investments generally improve grid conditions.

3. *Conclusions*

4. DTE's much longer than four-to-five year cycle for visual pole and pole top equipment inspection and replacement exposes the system to continuing significant reliability risk. (See Recommendation #4 and Chapter One Conclusion #15 and Recommendation #5)

The previous chapter of this report describes the commonality in the industry of visual overhead circuit inspection cycles much shorter than either DTE's current PTMM cycle or the ten-year cycle it plans for the future. With so many circuits so long since last treatment, DTE does not have the visual control of its system needed to establish physical control over pole and pole-top equipment conditions posing the most immediate failure and outage threats.

The reject rates DTE reports finding through its inspections appear to render the DGP's estimates of annual PTMM investments too low. DTE's latest estimates of 2027 and 2028 PTMM costs appear to use an amount per mile that exceeds the DGP's rates by 20 percent. Early rates likely materially exceed those that will apply as work proceeds to lower priorities. Nevertheless, it is clear that moving from the planned PTMM cycle to a far more appropriate four-to-five year overhead circuit inspection one will increase costs for the early years. It will not do so over time, however. For example, after completion of one four-to-five year cycle, the entire system will have been addressed, producing significantly lower inspection reject rates thereafter. By comparison, under a 10-year cycle, 60 percent of the system will still await inspection, repair, and replacement.

Recent changes to PTMM methods and scope have produced a more than doubling of work required. Given the large costs already involved and the short-term increases that a shorter cycle will generate, there is substantial merit in tightening, until system visual and physical control are established, rejection criteria and work scope and material standards. Moreover, while inspections should not be delayed, given the visual system control issue at stake, prioritizing repairs and replacement in a way that will backlog less critical ones can reduce immediate-term impacts by deferring less critical work to the second cycle, which will produce significantly lower repair and replacement rates.

5. Completion of the City of Detroit 4.8kV hardening program as the DGP plans is sound.

This program, which continues the removal of arc wire that formed an integral part of its institution, is nearing completion. It has improved resiliency and safety.

6. System Equipment Replacement work comprises a candidate for slowed investment pace, given lack of assignment of significant reliability improvement to performing it at the pace the DGP plans. (See Recommendation #5)

While surprising, it appears that DTE has not identified reliability improvements for its \$365 million in planned System Equipment Replacement expenditures. We found appropriate plans to perform the work planned for this category, but absent a more clear tie to sustaining and improving reliability, significant extension of the schedule for doing so can move half that amount and perhaps more past the DGP horizon. Reliability maintenance, versus improvement, and avoiding

the risk of high-consequence failures warrant attention in identifying from this group of investments those with greatest potential for deferral.

In addition, the potential for securing significant cost savings by rejuvenating versus replacing URD cable shows enough promise to warrant careful study and analysis, as recommended in the previous chapter.

7. We found sound the DGP's CE and CEMI investment levels, but not the lack of measures to address customers experiencing particularly long interruptions. (See Recommendation #6)

DTE has comparatively very high numbers of customers who experience high numbers of interruptions, which its CE and CEMI programs address. However, DTE also has comparatively very high numbers of customers who experience particularly long interruptions, as measured, for example, by the CELID index measuring numbers of customers experiencing long durations.

4. Recommendations

4. Establish a four-to-five year visual overhead circuit inspection program, pacing the scope and timing of repair and replacement activities to mitigate the added costs that the first cycle will produce. (See Conclusion #4 and Chapter One Conclusion #15 and Recommendation #5)

PTMM and 4.8kV Hardening work have been material contributors to reliability maintenance and improvement, however, difficulty exists in assigning levels of improvement between the work of these programs and the contribution made by the tree clearing that precedes them. The approaching completion of 4.8kV Hardening, and significant issues with the PTMM program as designed, warrant a new approach.

After establishing system control, a four-to-five year cycle is not inherently more expensive, as demonstrated by the broad use in the industry of such durations. The problem for DTE is in establishing that control. At present, the long lengths between visits to circuits make it impossible for DTE to have sufficient knowledge of the work it will take to get to control. In other words, DTE needs through more frequent and regularly conducted overhead circuit inspections to get visual control of pole and pole-top equipment conditions across the system. Based on inspection rejection rates to date, DTE appears now to estimate much greater needed repair and replacement work than it did when constructing the DGP. We believe that it would overstate work and costs requirements across a full inspection cycle (whatever its length) to assume that current reject rates will not come down as work continues to move past the worst circuits that receive priority attention. However, the rates that DTE has been finding do indicate a costly process for getting the system under visual control and as much physical control as is possible over the DGP period, given competition from many system needs to be addressed.

Circumstances do indicate that it will take a considerable effort to complete a first cycle of the common industry length that we recommend. It would, however, be incorrect to see high first-cycle work and expenditures as continuing thereafter. After covering in four years what DTE now proposes for ten, continuing costs will decrease significantly. As much is clear by the commonality of the significantly shorter cycle we recommend in the industry. Inspection costs (a comparatively

small portion of the total) will remain higher but repair and replacement costs will fall substantially. It is not realistic to suggest that a decade of repair and replacement work under four year inspection cycles will prove greater than that of a longer, 10- or 20- year cycle. It is clear, however, that fewer pole and pole-top equipment failures will result and that restoration costs will come down when damage and defects are discovered and remediated more promptly.

DTE does not yet have what we consider a usable set of data and analysis for determining the increased costs of moving to a four-to-five year cycle, but we believe it is very clear that the added costs of getting there are temporary and will be offset by lower costs under a continued four-to-five year cycle, both in the form of reduced inspection rejection rates requiring repair and replacement and in lower costs to conduct emergent work due to the existence of lower numbers of damaged and deteriorated poles and equipment.

Because its other system maintenance and improvement needs are so great, it is incumbent on DTE to prepare a credible analysis of the costs of moving to a shorter cycle, considering the impacts on succeeding cycle costs and on emergent work. Those other cost burdens also warrant an examination of how to phase in the shortened cycle. Exploring in detail the criteria and standards changes that have caused PTMM work to expand so significantly can identify measures that can lower first cycle costs by moving less critical work to subsequent cycles, whose costs will be lower, by making rejection criteria more narrow, and by scaling back the scope of repair and replacement work.

5. Replan and prioritize System Equipment Replacement investments to extend their completion by five years. (See Conclusion #6)

In order to permit an analysis of the path that electricity prices will take under the DGP, it is useful to examine the effects of extending the plan's System Equipment Replacement investments, given the lack of assignment of material reliability benefits to them. We do not find them inappropriate or unnecessary, but neither is the schedule set by the DGP convincing in terms of identified need of completion within five years. The analysis should consider whether that extension is likely to produce reliability degradation or threaten failures with high consequence (*e.g.* for environmental reasons), which should be considered in determining deferral priorities among these investments.

For reference, note that the recommendation of Chapter 1 to evaluate injecting vintage URD cables as an alternative to replacing them. If feasible, this injection, or "rejuvenation" process may offer material cost savings.

6. Expand the CE and CEMI programs to include problem CELID customers. (See Conclusion #7)

DTE should expand its programs to include problem CELID customers. The DGP plans an increase of some 50 percent to DTE's CE and CEMI programs. DTE should apportion that amount among problem CEMI customers (which its CE and CEMI programs both address), and problem CELID customers.

F. Pillar Three: Infrastructure Redesign and Modernization

1. Background

This pillar includes addressing capacity limits and consideration of undergrounding. The one-third of DTE’s distribution system built before 1965 faces limitations in providing the expected capacity that growing electric vehicle and home heat pumps and appliance use are expected to bring, along with growth experienced and expected in some locations in the Company’s service territory. DTE plans significant investments for converting portions of the 4.8kV ungrounded system to the modern, 13.2kV grounded system to improve safety and reliability, as well as providing additional capacity. The DGP also reports that DTE will “analyze and consider” moving wires underground as part of the process. This pillar also includes more than \$500 million in investments to increase subtransmission system capacity to address system loading constraints.

2. DGP Measures

a. Distribution Load Relief

Good utility practice requires regular analysis of loads placed on equipment relative to their ratings. That analysis must include consideration of future loads as well, given the lead times in planning configurations to meet needs that vary across the system, and to perform required design, procurement, construction, and completion in time to meet expected changes in the demands to be placed on the system. Planners rely on three principal equipment ratings in assessing their current and future suitability for meeting those demands. Two of them consist of:

- *Day-to-day*: the load at which equipment can be expected to operate under normal conditions without loss of expected life
- *Emergency*: the generally higher load at which equipment can be expected to operate without failure under contingency conditions for short periods of time, but with possible loss of expected life.

Substations also have a firm rating identifying the maximum load they can be permitted to carry in contingency conditions. This rating may fall below load levels that can damage equipment.

DTE reported that Annual Area Load Analyses (“ALAs”) that model prior and expected loads applying the above ratings have identified capacity limitations at about a third of its substations or the circuits they serve. DTE applies what it terms its Global Prioritization Model (“GPM”) to evaluate projects identified as candidates for eliminating priority loading constraints. Prioritization of substations or their circuits identified as candidates for relief employs five “variables”:

- Peak load nearing or exceeding day-to-day or emergency ratings of the most limiting equipment component
- Substation peak load exceeding firm rating under contingency conditions
- Peak load exceeding circuit day-to-day or emergency ratings
- Existence of known substation load growth
- Substations with circuits exceeding Distribution Design Orders (“DDOs”), intended to preserve operating flexibility and improve restoration options.

The Company’s planning criteria use 80 percent of firm capacity rating as a criterion for reinforcement. We found that level, which accommodates needs for load transfers when required,

consistent with our experience. DTE also determines emergency values which seek to limit operations of substation transformers above that 80 percent figure. Though not shown on the chart, these values range from 150 to 180 percent of a substation transformer’s nameplate capacity.

The DGP proposes investments for relief at the highest ranked substations identified by applying these variables and for related work. Building new substations, expanding existing ones, replacing transformers and other equipment, and creating new distribution circuits comprise the typical relief methods planned. DTE does not have but is developing forecasting tools that will identify needs at the feeder level, which will have bearing as electric vehicle adoption accelerates. The next table summarizes the DGP’s planned \$381 million in investments to provide load relief.

DGP Load Relief Investments

2024	2025	2026	2027	2028	Total
\$47	\$75	\$59	\$100	\$100	\$381

millions of dollars

The amount proposed to be spent reflects a more than ten-fold increase in management assigned to System Loading investments over the 2019 through 2023 period.

b. Subtransmission Redesign and Rebuild Program

DTE’s subtransmission system links the ITC transmission system with DTE’s distribution system and substations dedicated to individual large customers. The DGP describes a four-part strategy for improving subtransmission reliability, safety, and efficiency:

- Improve reliability near-term through the PTMM program
- Complete 40kV APTS device replacement (addressed above) to increase subtransmission automation
- Redesign and rebuild subtransmission sections to current standards to improve reliability, safety, and efficiency, increase capacity where constrained or experiencing load growth, increase automatic restoration, and improve truck accessibility
- Decommission the 24kV system in coordination with the 4.8kV conversion strategy (addressed below).

Planned subtransmission overhead line work includes equipment to add capacity, replacement of wood with stronger steel poles, installing new insulators, and replacing aging conductors with one designed for 90 mile per hour winds and offering more capacity. Work on underground subtransmission lines includes replacement and upgrade of overloaded and at-risk cables.

DTE applies the following six criteria in prioritizing subtransmission redesign and rebuild projects:

- Total line load lost when a single contingency occurs
- Load exceeds line emergency rating when a single contingency occurs
- Load exceeds line day-to-day, normal rating
- Line voltage drop exceeds standards when not in normal configuration
- Lines expected to experience load growth
- Line history of outages or equipment failures.

The next table summarizes the DGP’s planned subtransmission redesign and rebuild investments.

DGP Subtransmission Redesign/Rebuild Investments

Year	2024	2025	2026	2027	2028	Total
Amount	\$100	\$100	\$108	\$108	\$108	\$524

millions of dollars

The Company reported spending on “Subtran[smision] Hardening/Redesign” of \$135 million for the five-year period from 2019 through 2023. That data also reported 2024 through 2028 projected spending of \$599 million, an increase of \$464 million. The Reliability Model does not appear to assign any reliability improvements to this category of expenditures.

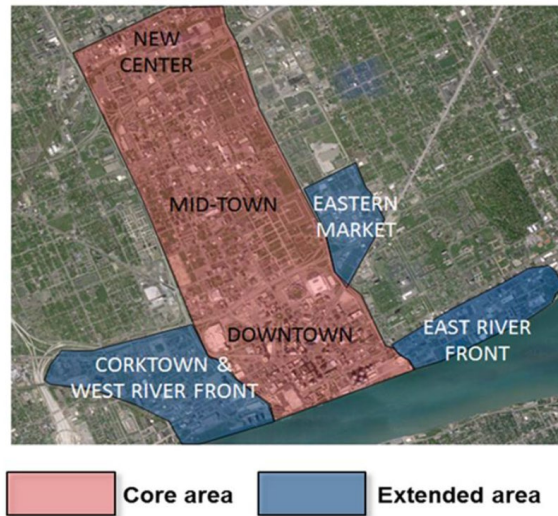
c. 4.8 kV Conversion

The 4.8kV system that DTE has used since first construction of its distribution system continues to serve just over half (1.21 million) of the Company’s 2.35 million customers. The ungrounded delta configuration means, as described earlier, that conductors will remain energized when downed in many cases and that fault location is more challenging. The circuits serving most neighborhoods still using this configuration employ rear lot overhead circuits. Access to most of these circuits located in the City of Detroit via municipally maintained alleys has become much more restricted, with government abandonment of alleys and property owner extension of fencing and other obstacles. Loss of ready access makes regular maintenance and outage restoration more expensive and time consuming. Since the 1960s, installation of 13.2kV grounded circuits have improved access and maintenance and restoration efforts, with DTE citing:

- 40 percent reduction in outage restoration time
- Decreased risk of down wires remaining energized
- Faster fault detection and location identification
- Stronger conductor more resistant to failure
- Increase in capacity
- Improved voltage regulation.

The 4.8kV system still accounts for a very large portion of DTE’s distribution system facilities. Its 244 general purpose substations comprise about 45 percent of the Company total and its 16,600 overhead circuit miles about 60 percent. The City of Detroit Infrastructure (“CODI”), plan, scheduled for 2035 completion, forms part of DTE’s 4.8kV replacement plan. The Company treats it distinctly from its other 4.8kV conversion work, given the area’s high concentration of underground facilities. CODI addresses facilities serving 31,800 customers and a number of institutions and large public venues in the areas of the city of Detroit shown in the next illustration.

CODI Area



The conversion of 4.8kV circuits comprises a particularly large portion of planned DGP investments, accounting for almost \$1.5 billion, as the next table summarizes. However, even this very large sum represents only a small portion of the amounts it will take in later years to address the nearly 16,000 overhead 4.8kV circuit miles and 200 substations that will remain. It will take, according to DTE’s “aspirational” goal another \$20 to \$25 billion more to convert the remainder by 2040.

DGP 4.8kV Conversion Investments

Program	2024	2025	2026	2027	2028	Total
CODI	\$95	\$126	\$148	\$119	\$90	\$579
ISO downs	\$10	\$10	\$10	\$10	\$10	\$50
Other 4.8kV	\$66	\$66	\$185	\$243	\$310	\$869
Total	\$171	\$202	\$343	\$372	\$410	\$1,498

millions of dollars

The Reliability Model includes a moderate reduction to \$1.367 billion for “Conversion.” The Reliability Model projects 38 minutes of all-weather SAIDI improvement to Conversion through 2028.

4.8kV conversion work includes:

- New or upgraded 13.2kV substations and consolidation/decommissioning of 4.8kV substations
- Substation and circuit controls and automation installations that meet current standards
- Circuit consolidation, reconfiguration, and new jumpering points to meet current design standards
- Overhead pre-conversion as needed; e.g., pole and transformer replacement, pole-top work, neutral wire installation.

As noted, CODI operates under a specific plan and schedule. DTE has coordinated conversion of other 4.8kV circuits with plans (discussed above) to address the loading limits faced by a large number of its substations and circuits. Specific criteria for prioritizing these other conversions include substation firm ratings, the existence of circuit overloads, wire down incidents per mile and substation risk ranking. Substation ratings and risks are not applicable for 4.8kV circuits already fed by 13.2kV substations (“ISO downs”). Replacement prioritization for these circuits considers wires down numbers, customer minutes of interruption, and avoided costs following conversion.

d. Pontiac 8.3kV Conversion

The DGP’s Infrastructure Redesign and Modernization pillar includes investments for converting the 8.3kV City of Pontiac distribution system, acquired by DTE in the 1980s. The Company cannot transfer load to its surrounding 13.2kV system, when it would serve operational purposes such as conducting repairs without requiring outages. The lack of replacement parts for the vintage facilities involved also extends outages for operations and maintenance or for unexpected reasons. DGP work involves decommissioning four substations, upgrading one, converting circuits, moving them to other substations, and upgrading of customer services fed by underground 8.3kV equipment. The DGP plans 2024 through 2028 investments of \$114 million to accommodate this work.

e. Undergrounding

DTE has completed one undergrounding pilot project and the DGP describes plans for another to develop capability and cost information for use in relocating “significant” portions of its overhead facilities underground, examining and testing alternate construction methods, joint construction work with DTE Gas, urban versus rural differences, and customer outreach. Management plans to use benchmarking to address other company practices and to identify cost reduction methods.

DTE’s examination of undergrounding cost differentials has produced plans not for a full conversion program, but rather for the conduct of pilots to accomplish data gathering and analysis purposes. However, DTE does consider aligning undergrounding with extensive 4.8kV conversion an opportunity, given the large scale of rebuilds under the latter program. The results of one undergrounding pilot, the Appoline DC 1346 circuit, produced significant cost, time, and customer outreach requirements for back lot undergrounding. A cost/benefit analysis for Appoline awaited project completion at the time of DGP filing. DTE reports that benchmarking with a group of ten other utilities demonstrates a preference for front-lot versus rear-lot, direct buried (“URD”) facilities, in terms of customer experience, reliability, and aesthetics. Additionally, DTE’s benchmarking found that the peer utilities will complete easement acquisition and gain any necessary customer agreements prior to executing such a project. Benchmarking also indicates that large scale programs produce cost efficiencies and that undergrounding single phase laterals proves less costly, given the standards required for three-phase and backbone circuits.

3. Conclusions

8. The DGP appropriately plans for large investments for load relief at substations.

DTE clearly has a significant number of substations whose equipment has well exceeded planning criteria, calling for reinforcement. The ten-fold increase above historical levels indicates a lack of consistent prior attention to these needs.

9. DTE recognizes and is working to develop forecasting tools that can identify feeder-level needs. *(See Recommendation #7)*

Increasing penetration of load sources like electric vehicles can impose significant capacity issues below the substation; *i.e.*, at the feeder level. Driving forecasting granularity to this “edge of the grid” level will enable DTE to target investment more directly and economically, as may prove necessary to meet the state’s EV penetration targets. As has become common, DTE is seeking to find and develop tools that will allow this granularity. It is important that those efforts remain a priority, in order to target capacity investments in a way to optimize costs.

10. The DGP’s Subtransmission Redesign and Rebuild Investments offer a primary candidate for duration extension and therefore significant cost reduction through the plans’ horizon. *(See Recommendation #8)*

The DGP calls for somewhat more than \$0.5 billion in investment, which indicates annual spending at a rate more than three times the reported levels of recent years. The plan cites capacity as a major driver, but includes automation, reliability, and rebuilding to modern standards as included benefits. It is not clear how the factors other than reliability apply given that the subtransmission system does not significantly contribute to SAIDI minutes and that the Reliability Model does not appear to project reliability metrics improvements for this category of expenditures. The DGP also cites decommissioning of the 24kV system in coordination with the conversion of 4.8kV facilities (discussed next). DTE believes that its attribution of reliability impacts between subtransmission and distribution circuits requires improvement. Work is underway to improve that attribution. It is important to ensure that accuracy in this regard is secured and maintained. There is process improvement opportunity to appropriately account for the reliability impact of the subtransmission system to further strengthen the justification of subtransmission redesign and rebuild projects.

11. Prioritizing DGP-horizon 4.8kV conversions to those areas facing capacity constraints reasonably confines their scope, but does not foreclose the need for formulating in the near term a longer term plan identifying how much of the 4.8kV system to convert and over what duration. *(See Recommendation #9)*

As expensive as it is, the DGP’s \$1.5 billion cost for 4.8kV conversions represents only a downpayment against the aspirational DTE goal of completing that conversion by 2040 at a cost it pegs at \$20 to \$25 billion. DTE states that it has limited DGP investments for such conversions to areas where the system faces capacity limitations that require relief. There is only a single exception, the MDOT expansion of the Port Huron Bluewater Bridge. It is reasonable to provide that relief at the standard 13.2kV and thus to convert the involved 4.8kV facilities to that design. With such a large investment even during the DGP period, however, DTE needs to remain diligent in ensuring that the capacity limitations now driving conversion remain as conditions change over the next several years.

12. The 4.8kV conversions over the DGP period should not diminish the priority on completing installations of reclosers at substation exit points. *(See Recommendation #10)*

As noted earlier, DTE should complete the installation of reclosers at substation exit points as soon as possible. Completion should not be extended to accommodate 4.8kV conversions. The Viper devices planned are subject to reuse elsewhere after they are no longer needed for the safety reasons that command priority use.

13. With vault conditions slated to have been addressed in 2023, the Pontiac 8.3kV conversion does not appear to present immediate need for execution, given other, very large investment needs. (See Recommendation #11)

The vaults that DTE has upgraded continue to be fed by 8.3kV breakers planned for replacement to permit conversion to 13.2kV. DTE reports that breaker repairs involve extended outages for some 7,000 services fed by them. Repairs also require a portable substation and a portable ISO trailer and take two to three weeks. The roughly \$100 million Pontiac conversion presents an opportunity for reducing investments over the DGP period.

14. Because DTE lacks enough information to make firm conclusions about the costs and benefits of undergrounding, it is appropriate to limit expenditures to a pilot program before deciding whether undergrounding should have widespread application. (See Recommendation #12)

The experience of other utilities identifies the need for careful evaluation of the costs and benefits of undergrounding and underscores the criticality of DTE efforts to gain more information specific to its own circumstances. The Company has acknowledged that it does not have sufficient information to make a sufficiently informed decision to commit to a full-scale program. Management plans to add, if approved by the Commission, additional pilots. The first has apparently encountered execution difficulties; *e.g.*, in customer outreach and approval.

It is important to conduct pilots that target those areas that present the largest opportunity for installations at lowest costs and that their conduct eliminate constraints that can undermine results. Delays due to customer outreach and approval, for example, can have significant cost implications.

4. Recommendations

7. Pursue and complete the development of feeder-level load forecasting tools. (See Conclusion #9)

Already underway, DTE should complete efforts to identify and develop feeder-level forecasting capability. Grid management platform and service providers have made advances in providing this developing capability, providing both increasing options and complexity in finding a combination of outside support and inside development that will meet DTE's needs in a way it can incorporate effectively into its suite of planning systems and tools.

8. Isolate and provide Subtransmission Redesign and Rebuild Investments for those required for capacity reasons and 4.8kV conversion. (See Recommendation #10)

Again, with the programs, measures, and activities planned conceptually sound, the more important question becomes which of them can be reduced and by how much, given affordability and value. Capacity and support for 4.8kV conversion (as recommended immediately below) have a sound foundation. However, it is not clear that investments to increase automation or reliability

are warranted or will have a measurable impact on reliability measures. After isolating the investments required for capacity or 4.8kV support, it is reasonable to conclude that continuation of recent-year levels of subtransmission capital work will need to continue.

DTE emphasizes capacity needs in describing the purpose of Subtransmission Redesign and Rebuild Investments. However, the DGP cites “aging infrastructure” and “increasingly severe weather events,” both reliability issues, as factors, noting that the investments are designed to “...improve the reliability, safety, efficiency and system capacity of the subtransmission system in both the near and long-term.” The work includes replacement of wood with steel poles, porcelain with polymer clamp top insulators, and small diameter with larger, stronger conductors.

It is reasonable to conclude that investments beyond those historical levels, with amounts shown necessary for capacity and 4.8kV conversion support added are appropriate, particularly given the high levels of expenditure already required. Annual reductions of between \$90 to \$100 million per year provide a measure of the investment reductions achievable.

9. Limit 4.8 kV conversions to those necessary for substantial capacity reasons. *(See Conclusion #11)*

DTE’s planning for 4.8kV conversions limits them to cases where capacity limits apply, which is sound. The large investments that nevertheless result under the DGP command continual attention to changes in expected load conditions that identify reinforcement needs. As expected load conditions change, which they inevitably will in certain particular locations on any electrical system, DTE needs to adjust its list of conversions slated (consistent with lead time limitations) to identify where constraints on a projected basis have either eased or tightened to ensure that the work eventually performed continues to meet rigorously applied capacity planning criteria through to the time when project milestones have been reached.

10. Plans for 4.8kV conversion should not reduce the priority on safety-driven recloser installation as promptly as practicably achievable. *(See Conclusion #12)*

This issue is fully addressed in Chapter One of this report.

11. Re-examine the justification of the Pontiac conversion. *(See Conclusion #13)*

While the DGP cites load transfer limitations, parts availability, and load growth as qualitative factors warranting conversion of the City of Pontiac 8.3kV system, it does not provide quantitative dimensions addressing the risk of equipment failures that would require load transfers, the outage times likely to result, the costs of making parts available, or the degree to which load changes have created or are creating capacity constraints. In the absence of more analysis, deferral of the conversion should be considered as a means to save about \$100 million in DGP investment amounts.

12. Hinge commitments to significant undergrounding on the results of carefully planned piloting. *(See Conclusion #14)*

DTE is correctly approaching consideration of a significantly scaled undergrounding program. It has been engaged in conducting one pilot and is appropriately planning a second, moderately scoped one. It is important that the selection of future pilots address logistical, scheduling, and

other constraints that can impose significant added costs that lessons learned can be reasonably expected to avoid. It may well be the case that finding opportunities to build an undergrounding plan of sufficient scale to contribute materially to reliability will take multiple test cases to determine areas and field conditions that produce best costs and to align them with circuits that will benefit most from undergrounding in terms of reliability. DTE should present, should first efforts show promise, a description of the full scale of pilot or test cases proposed to demonstrate scalability, develop a five-year plan for implementation, addressing expected costs and benefits, describing prioritization methods, and providing a reporting cycle and content designed to keep the Commission annually informed about actual costs and benefits achieved.

G. Pillar Four: Technology and Automation

1. Background

The U.S. Department of Energy has a Distribution System Platform Initiative which provides a framework that DTE has used to assist in determining where its grid displays gaps in moving from one serving today to one expected to serve adequately in the future. The DGP recognizes gaps in physical infrastructure, like those addressed under the preceding three pillars, as far and away the largest it needs to close, both in terms of required investment amounts and as part of establishing a sound foundation for meeting future needs. This Technology and Automation pillar addresses elements of grid design and operation that have become increasing focuses more recently. These elements of Observability and Controls, Analytics and Computing Platforms, and Communications address the use of ever-expanding technology to gain real time information. The information involved addresses what is happening on and disturbing the grid, preventing, controlling, and responding to conditions on a real time basis, using technology to analyze the system for operational and for planning purposes, and for communicating information on as real time a basis as possible. Ensuring timely access to common information among all systems critical to system operation and to operators who have to make prompt decisions is also critical. Even field resources for whom gains in efficiency under trying circumstances can materially shorten outage durations, benefit from faster access to accurate and integrated data, and priorities.

The DGP lists Grid Automation, Grid Management, Distribution Planning, Work Management and Scheduling, Asset Management, and Mobile Technology as DGP investment and other expenditures focus areas.

2. DGP Measures

a. Grid Automation

The DGP plans for expenditures on physical infrastructure like reclosers, capacitors, voltage regulation equipment, and support for non-wires alternatives (“NWAs), EVs, grid telecommunications, and advanced metering infrastructure (“AMI”) systems updates. DTE standards call for SCADA-operable substation breakers and tie points on new and rebuilt facilities. These standards also call for three-phase reclosers, capacitor controls, digital relays and communications protocols meeting advanced protection requirements for newly constructed and rebuilt distribution facilities. DTE also plans to extend the use of devices such as sensors and reclosers as it extends Fault Location, Isolation and Service Restoration (“FLISR”). Even for lines not slated for rebuilds, DTE plans to install more than 10,000 distribution line reclosers and to

upgrade large numbers of switching and tie points, expanding the ability to restore service before completing repairs.

The DGP’s Grid Automation categories include:

- Grid Automation: Install SCADA control, automation and ground identification and isolation to reduce sustained outages, minimize outage size, reduce crew patrol and operating time, and minimize impacts of system grounds
- Grid Telecommunications: Install fiber backbone to substations and wireless mesh for more bandwidth and resiliency to support new automation devices
- Conservation Voltage Reduction/Volt-Var Optimization (“CVR/VVO”) Reduce system losses, save energy, increase system efficiency, improve voltage and power quality
- Capacitor Placement and Control: Optimize capacitor locations, replacing end-of-life controls to improve system efficiency and voltage
- Non-Wire Alternatives (“NWA”): Demonstrations for energy storage, efficiency, demand; enable greater DER integration and create future program and NWA integration methods.

The next table summarizes grid automation investments under the DGP.

DGP Grid Automation Investments

Program	2024	2025	2026	2027	2028	Total
Grid Automation	\$61.6	\$162.6	\$190.6	\$308.6	\$469.0	\$1,192.4
Grid Automation Telecommunications Program	\$16.9	\$15.0	\$13.8	\$12.5	\$11.0	\$69.2
CVR/VVO Program	\$5.0	\$5.0	\$5.0	\$5.0	\$5.0	\$25.0
Capacitor Placement and Control Program	-	\$5.6	-	-	-	\$5.6
NWA Projects	\$14.5	\$1.3	\$0.3	-	-	\$16.1
Grid Edge Enablement Program	\$5.5	\$4.2	\$4.2	\$3.0	\$2.8	\$19.7
Vehicle Electrification Projects	\$2.9	\$1.0	\$0.8	\$0.8	\$0.5	\$6.0
URD Fault Indicators	\$3.0	\$3.0	\$3.0	\$3.0	\$3.0	\$15.0
New Technology Evaluation Program	\$1.2	\$1.0	\$1.0	\$1.0	\$1.0	\$5.2
Line Sensors	\$0.5	-	-	-	-	\$0.5
Large/Medium Sized DER Monitoring and Control	\$0.3	\$0.3	\$0.3	\$0.3	\$0.3	\$1.5
Total	\$111.4	\$199.0	\$219.0	\$334.2	\$492.6	\$1,356.2

millions of dollars

In the category of Distribution Automation, the Company’s 2019 through 2023 expenditures totaled \$1 million and 2024 through 2028 proposed expenditures total \$1.164 billion dollars. The Reliability Model reduces projected 2024 through 2028 expenditures for Automation to \$995 million and improved reliability metrics performance of 225 minutes to all-weather SAIDI through 2028.

The first component that calls for substantial SCADA investments comprises over 90 percent of the total. DTE plans to provide SCADA monitoring and control of all overhead distribution circuits, and add new and other automation devices to reduce outage impacts. Citing a 2016 study, the DGP noted 17 to 55 percent reductions in customer minutes interrupted after automation and projects an average of 25 to 50 percent reductions from DGP-planned investments. Reliance on a study from so long ago raises questions that include:

- What other work may have been performed or not performed (*e.g.*, duration since last vegetation treatment)
- Changes in the range and cycles of programs applied since (*e.g.*, vegetation, pole, and pole-top inspection cycles)
- Incremental improvements from automation versus such other measures
- Typicality of circuit conditions (*e.g.*, worst performing or not)
- Degree of work remaining to complete automation (*e.g.*, if work prioritized by circuit condition or performance, are conditions on remaining circuits less severe).

Circuit reclosers comprise a central element of the Technology and Automation investment for the DGP plans. DTE views its new ESOC as a hub for managing a grid with increased ability to detect and de-energize downed wires, particularly as 4.8kV work proceeds. Outage Management System (“OMS”) and Distribution Management System (“DMS”) components recently incorporated into the ADMS enable installation of equipment that will support planned completion of full automation of the distribution grid during the period the 2023 DGP covers.

Telecommunications expenditures will expand fiber loops and establish dedicated communication links to more endpoints. The CVR/VVO investments will expand a program, first piloted in 2022, that has produced peak demand and energy consumption reduction. Capacitor and NWA investments are nominal.

b. Grid Management

Effectively managing modern grid operations requires significant use of operational technology (“OT”) for monitoring, control, and operations optimization. An effective ADMS provides a foundational set of capabilities needed for these purposes. A well-designed and integrated ADMS houses and manages data, makes it available for real time use in many key cases, enables prompt fault location, controls system operations to respond to faults, makes outage response more timely, efficient, and provides automatic service restoration in many instances. As DERs come to play an increasing role and provide added challenges in grid operation, a Distributed Energy Resource Management System (“DERMS”) becomes more significant as well. The DGP describes a series of Grid Management Investments:

- ASOC: electronic displays and platforms to support dispatcher and operator needs for systems on which they relay, such as SCADA, EMS, DMS, and OMS
- ADMS: for integration, performance and capability enhancements
- EFC/PPS: for enhancements to outage status communications and storm response technology
- Meters: to improve situational awareness and use of energization
- Microwave End of Life: retirement of previous communications infrastructure
- FLISR: to minimize outage scope through fault location and automated switching and optimizing restoration
- DERMS: for ADMS interfaces to optimize DER dispatch, add programs, integrate more DER, improve grid reliability
- Cyber Security: to harden against cyberthreats through standardized tools, hardware, and practices

- Automation Configuration Database: to convert to an industry standard relay and control settings database, purchase test sets to increase efficiency and accuracy of automation equipment
- \$10.2 million for investments categorized as Other.

DGP Grid Management Investments

Program	2024	2025	2026	2027	2028	Total
ADMS	\$7.0	\$7.0	\$7.0	\$7.0	\$7.0	\$35.0
FLISR	\$7.4	\$6.4	\$6.4	\$6.4	\$5.9	\$32.5
EFC/PPS	\$5.6	\$1.4	\$1.4	\$1.1	\$0.4	\$9.9
DERMS		\$1.5	\$2.8	\$2.8	\$2.8	\$9.9
Meters	\$1.4	\$1.4	\$1.4	\$2.8	\$2.8	\$9.8
Database	\$1.4	\$3.2	\$3.2			\$7.8
ASOC	\$3.9					\$3.9
Cyber	\$0.8	\$0.8	\$0.5	\$0.5	\$0.5	\$3.1
Microwave	\$0.5	\$0.5	\$0.5	\$0.5	\$0.5	\$2.5
Other	\$2.2	\$3.5	\$1.7	\$1.4	\$1.4	\$10.2
Total	\$30.2	\$25.7	\$24.9	\$22.5	\$21.3	\$124.6

millions of dollars

c. Distribution Planning

Distribution planning encompasses all technology dimensions needed for distribution planning, design, specification, modeling, forecasting and analytics. DTE’s Advanced Distribution Planning System (“ADPS”) employs a range of tools that assist modeling and planning of the distribution system and its needs on a going forward basis. The DGP describes a series of tool enhancements to key components, which include CYME, Power Runner, SEEQ and PSSE. DGP investments address hosting capacity, interconnection processing, distribution planning, power quality analysis, DERs, load forecasting analysis, and power flow analysis. DGP Distribution Planning investment areas include:

- Network Management System (“NMS”) Phase 2: to improve cohesion and accuracy in using GIS, asset, and system model data
- Load Allocation Analytics: to consolidate data into an analytics platform that integrates SCADA, AMI, and load forecast data
- CYME: to incorporate added data for running hourly system analyses
- Forecasting and Propensity Analysis: to create locational DER and electrification scenarios for planning tools
- Interconnections Process Enablement; to improve interconnection tools and processes, streamlining interconnection application analysis
- Hosting Capacity: enhance data publicly available and its updating
- Subtransmission Planning: to integrate system and DER data, remain compliant with MISO modeling requirements
- Power Quality: to improve fault, disturbance, and power quality event data, processing, and analysis, to improve anomaly risks identification, detection, and causal analysis
- Substation and Structural Design: to enhance design accuracy, efficiency, standardization, and compliance.

The next table summarizes DGP investments for Distribution Planning.

DGP Distribution Planning Investments

Program	2024	2025	2026	2027	2028	Total
Interconnections Process	\$1.9	\$1.7	\$1.7	\$1.8	\$1.5	\$8.6
Load Allocation Analytics	\$2.2	\$1.0	\$2.0	\$2.5	\$0.8	\$8.5
NMS Phase 2	\$1.6	\$2.8	\$2.1	\$1.5		\$8.0
CYME Enhancement	\$1.3	\$1.5	\$1.5	\$1.5	\$1.5	\$7.3
Substation & Structural Design	\$1.9	\$1.2	\$1.5	\$0.8	\$0.5	\$5.9
Forecasting & Propensity Analysis	\$0.2	\$1.8	\$0.7	\$0.4	\$1.5	\$4.6
Other Distribution Planning	\$1.6	\$2.2	\$0.5			\$4.3
Power Quality Analysis	\$0.4	\$0.5	\$0.4	\$0.5	\$0.4	\$2.2
Hosting Capacity	\$0.5	\$0.3	\$0.4	\$0.3	\$0.5	\$2.0
Subtransmission Planning	\$0.4	\$0.3	\$0.3	\$0.3	\$0.3	\$1.6
Total	\$12.0	\$13.3	\$11.1	\$9.6	\$7.0	\$53.0

millions of dollars

d. Work Management and Scheduling

Work management systems in use today provide a portfolio of tools for managing all the resources required to complete designated work scopes, including work orders, scheduling, work execution, post-completion work effectiveness review, and capture of time and other cost details for permanent recording and use. The DGP acknowledges the stresses that much enlarged work levels will place on the ability to maintain effectiveness, efficiency, and timeliness in executing it. DTE plans measures to enhance the systems and processes designed to do so. The objectives these enhancements seek include:

- Work status visibility from planning, to scheduling to execution
- Daily and weekly assessment of internal and contract crew availability
- Optimizing schedule prioritization and optimization
- Proper assignment and allocation of time worked to jobs
- Electronic access by all involved in work execution to job information and completion verification.

The DGP describes a series of Work Management and Scheduling programs:

- Maximo Transformation: to increase efficiency by creating a separate environment in the platform to support DTE-specific processes and optimizations
- Maximo Capabilities and Processes: to increase efficiency by optimizing Maximo for distribution operations
- Substation Reporting and Processes: to improve productivity by incorporating crew data in Maximo
- Primary Service Orders: to reduce restoration durations through a new platform
- External Crew Efficiency: to streamline external crew tracking and reduce costs through collection and processing of work time and related data.

The next table summarizes the DGP’s reported Work Management and Scheduling Investments.

DGP Work Management and Scheduling Investments

Program	2024	2025	2026	2027	2028	Total
Maximo Transformation	\$4.20	\$7.0	\$7.0	\$7.0		\$25.2
Primary Service Orders	\$2.00	\$4.1	\$1.1			\$7.2
Maximo Enhancement		\$0.8	\$1.1	\$1.4	\$2.1	\$5.4
Other	\$1.40	\$1.0	\$0.6			\$3.0
External Crew Efficiency	\$2.00	\$0.8				\$2.8
Substation Reporting & Processes	\$0.40					\$0.4
Total	\$10.00	\$13.7	\$9.8	\$8.4	\$2.1	\$40.8

millions of dollars

e. Asset Management

Well-designed asset management programs have also come to rely increasingly on continually advancing tools and systems, like IBM’s Maximo and ESRI ArcGIS, cited by DTE as its primary asset management systems. The DGP describes plans for a number of Asset Management investments:

- ESRI ArcGIS: to reduce costs and improve operational data, updates, update and restructure system to eliminate redundancies
- ESRI Utility Network: to conduct pilot to test preparation for conversion to Utility Data Model (the next bullet)
- ESRI Utility Network: to improve system model, condition, and field markup through conversion to industry standard Utility Network Model, tools, and processes
- ESRI Map Data: to support more accurate, efficient design, through accurate location data
- ESRI Field Tool Integration: to improve accuracy of system model, asset condition and field markup through integration of as-built designs, asset status and as-found conditions capture
- Asset Assessment Frequency: to improve tools for targeting assets needing maintenance or replacement through real time health assessment
- Systematic Tracking of Rotatable Assets: to improve management through tracking using RFID.

The next table summarizes the DGP’s reported Asset Management Investments.

DGP Asset Management Investments

Program	2024	2025	2026	2027	2028	Total
ESRI Utility Network Conversion			\$4.20	\$4.20	\$5.60	\$14.0
ESRI Map Data Conflation	\$0.30	\$2.20	\$1.40	\$1.40	\$1.10	\$6.4
ESRI Field Tool Integration				\$2.80	\$2.10	\$4.9
ESRI ArcGIS		\$0.60		\$1.10	\$0.60	\$2.3
ESRI Utility Network Pilot	\$1.10					\$1.1
Rotatable Asset Tracking		\$0.60				\$0.6
Asset Assessment Frequency			\$0.40			\$0.4
Total	\$1.40	\$3.40	\$6.00	\$9.50	\$9.40	\$29.70

millions of dollars

f. Mobile Technology

Mobile devices have had a major impact in improving the efficiency of field resources, in expediting assignment and dispatch to work locations, in supporting data analytics, and in streamlining and enhancing the consistency and completeness of data that maintains control over configuration, content, and costs of field equipment. The DGP describes plans for integrating communications and workflow visibility among control room, field leader, field crew, and supporting organization personnel devices and applications designed for mobile use address dispatch, work execution and digitizing forms, sharing files, tracking locations, providing route navigation, and analytics. The Mobile Technology programs the DGP addresses seek to:

- Provide accurate information capture and access
- Give field resources applications that allow them more time in the field
- Provide ready mobile access to company systems and documents
- Improve field worker time tracking
- Reduce manual efforts and improve data quality.

The DGP describes plans for a number of Mobile Technology investments:

- Mobile Tools: expand site-available tools that support field work to improve efficiency
- Compliance: ensure practices that manage customer and operational data in accord with requirements
- Cyber: increase vigilance to ensure protection against increasing threats
- Mobile Equipment: replace end-of-life equipment.

The next table summarizes the DGP’s reported Mobile Technology Investments.

DGP Mobile Technology Investments

Program	2024	2025	2026	2027	2028	Total
Mobile Tools Expansion	\$1.1	\$0.8	\$0.7	\$1.1	\$1.1	\$4.8
Compass Mobile Tool	\$1.6					\$1.6
Maintain Compliance	\$0.6	\$0.6	\$1.1	\$0.6	\$0.4	\$3.3
Cybersecurity	\$0.8	\$0.8	\$0.8	\$0.8	\$0.8	\$4.0
Mobile Equipment Replacement	\$2.8	\$2.8	\$1.4	\$4.2	\$7.0	\$18.2
Other Mobile Technology	\$1.3	\$0.8	\$1.1	\$1.0	\$1.0	\$5.2
Total	\$8.2	\$5.8	\$5.1	\$7.7	\$10.3	\$37.1

millions of dollars

3. *Conclusions*

15. We do not find persuasive the conclusion that the installation of Viper reclosers will generate sufficient reliability improvements to warrant the DGP levels of planned investment. (See Recommendation #13)

DTE’s Reliability Model reduced the cost of Grid Automation from the DGP’s planned \$1.31 billion to \$995 million as reflected in the latest version of the Reliability Model provided by DTE. The principal reason for the drop is a reduction in the number of recloser units to 5,407. Projections of SAIDI minute reductions depend on results of factors that include:

- Only minimal numbers of units installed so far

- Accuracy in projecting the rate of diminishing returns as installations extend to better performing circuits over time
- Apportioning benefits between recloser installation and other reliability-contributing measures (*e.g.*, more recent vegetation treatment, PTMM work).

A slow initial pace of installation, while efforts to better account for factors like these is in order. The DGP does call for a significant ramp up in its later years, which allows for a pace that will better inform the determination of the optimal penetration level rate for reclosers. That optimal level should ultimately determine the rates of installation in later DGP years and beyond.

16. The DGP’s Grid Management investments are sound and reasonably moderate.

Grid Management accounts for \$124.6 million in investments over the DGP period. The planned applications to the ADMS, in conjunction with the grid automation assets, will improve the System Operations’ ability to monitor and control the subtransmission and distribution systems more effectively and more accurately by identifying fault locations and more quickly restoring service to customers by automatic means, remote control means, and otherwise by better dispatching first responders to locations of faults causing outages reducing CAIDI minutes.

17. The DGP’s Distribution Planning investments respond to important developments that planning needs to address and will improve data and analytical tools, all for a moderate cost.

Distribution Planning enhancements account for \$53.0 million in planned DGP investments. Their combination with ADMS applications will provide additional detail about the system and improve modeling of it. They will support the ability to identify emergent circumstances and configurations that threaten failures, and improve electrification and DER scenario development and available DER Hosting Maps. They thus support both classic planning activities and needs and those that come with a grid designed to meet expanded needs and access.

18. The DGP plans for an effective and moderately priced set of Work Planning and Scheduling enhancements.

Enhanced work planning and scheduling will prove critical to effective and efficient performance of the massive work levels facing DTE. The Company has begun major efforts to improve its focus on work planning and scheduling and, as we have noted earlier, development of a sophisticated set of systems and tools must accompany those efforts. The improvements sought and the projected investment levels to secure them are sound.

19. Similarly, measures to enhance data assembly and its use for Asset Management are sound and moderate in expected costs

The DGP’s planned \$29.7 million for improving asset data in its ArcGIS system to eliminate gaps and redundancies and its move, if a piloting effort bears out, to convert to the Utility Network Mode promise meaningful benefits across a range of Asset Management processes and activities.

20. The DGP’s investments in Mobile Technology are moderate in amount and consistent with capabilities now prevalent in the industry.

The DGP’s planned Mobile Technology expenditures of \$37.1 million appear designed to provide capabilities now commonly recognized as critical to maintaining effective communications across

the company and to promoting effective and timely dispatch field work efficiency, and accuracy of data.

4. Recommendations

13. Hinge the DGP's expansion of recloser installations over the plan's later years on the development of better informed information about their likely reliability contribution.
(See Conclusion #15)

Extending the proposed 2024 DGP unit installation rates through 2025 may well prove sufficient to develop sounder information about current and projected reliability benefits as penetration of the devices increases. At the same time, they remain fairly moderate. Thereafter, however, they ramp up significantly. With industry experience showing a clear pattern of diminishing returns as penetration increases and with the massive other investment demands facing DTE, we believe that it is reasonable to expect a \$600 million or so reduction from the DGP's proposed investment levels.

Note also that these reclosers are of the same type we recommend for accelerated installation at substation exit points. The limitations addressed in this recommendation should not serve to constrain those safety-driven installations.

Chapter III – Emergency Planning and Response

A. Background

Effective Emergency Planning and Response (“EP&R”) for electric utilities involves identifying and planning for weather events and other service disruptions, such as those caused by natural disasters, cyber, or terrorist attacks. It includes as well effective, efficient, safe, and timely restoration of customers experiencing outages. It should provide for:

- **Continuity of Service:** Electric utilities have responsibility for providing reliable power supply to their customers. An effective emergency plan and its execution help to minimize power disruptions and provide for quick and efficient service restoration when required.
- **Safety:** Emergency planning and response should protect the safety of utility workers, who need to perform repairs or maintenance in hazardous conditions, and the safety of the public potentially put at risk from downed power lines or other electrical hazards.
- **Regulatory Compliance:** Most jurisdictions have regulations requiring electric utilities to have an emergency plan in place and many have service quality standards associated with EP&R.
- **Reputation Management:** A well-managed emergency response helps protect the Company’s reputation. On the other hand, a poorly managed response can lead to negative publicity and loss of customer trust.
- **Risk Management:** EP&R assists electric utilities in managing risks associated with significant service interruptions. By planning for these events, utilities can reduce the likelihood of their occurrence and minimize their impact when they do occur.

We reviewed DTE’s EP&R function as it relates to weather events, not other potential causes of service disruption, such as cyber-attacks, geo-magnetic events, or attacks on key electric facilities. Our review focused on planning, internal and external communication, processes, tools, and execution underlying this critical function. The organization of this chapter of the report includes a review of the following:

- EP&R Plan and Organization
- Pre-Event Planning
- Event History
- Storm Impact Forecast Accuracy
- Restoration Performance
- Wire Down Processes and Performance
- Restoration Budgeting.

This chapter also includes a section on compliance with MPSC rules and metrics. The *Outage Communications* Chapter of this report addresses outage communication related topics (e.g., liaison with government officials, development of estimated times for restoration (“ETRs”), and communication to affected customers).

B. Findings

1. *Emergency Preparedness and Response Plan and Organization*

This Section of the report discusses the emergency planning organization and the major planning documents used by DTE for storm preparation and management. Emergency plans comprise a ubiquitous aspect of every electric utility emergency preparedness toolkit. They should provide a ready source of information, direction, processes, procedures, organization, schedule, notifications, and contact data, among other subject areas, to company personnel involved in the planning for and execution of restoration activities following weather related events that cause a service disruption. The plans should be comprehensive in nature, widely and easily available to affected personnel, well-structured for ease of communication and understanding, and reflect current organizational structures, position roles and responsibilities, reporting requirements, and processes and procedures.

Organization structure and staffing for EP&R groups vary widely among utilities. However, key characteristics of successful EP&R organizations include visible and vocal support from upper management, strong leadership, knowledgeable and experienced staff in key roles, the communication of planning documents to the wider utility groups and individuals that will assume central roles prior to, during, and post restoration, and revising those documents as necessary.

a. *Emergency Planning Documentation*

DTE’s emergency response manuals, known as “Playbooks,” reflect the Company’s adoption of the National Incident Management System (“NIMS”) and the Incident Command System (“ICS”) for electric restoration activities and emergency response. DTE fully adopted the structure in 2020 based on the NIMS emergency management structure, concepts, and principles. DTE employs 20 Playbooks, which it organizes by the roles shown below in weather events:

- *Customer Advocate*
- *Damage Assessment*
- *ECAC Manager*
- *Escalation Manager*
- *Estimates Manager*
- *Finance Chief*
- *Incident Commander*
- *Incident Management Team*
- *Logistics Chief*
- *Mutual Assistance Manager*
- *Operations Chief*
- *Planner Strategist*
- *Planning Chief*
- *Public Protection*
- *Safety Officer*
- *Service Restoration Manager*
- *Singles Strategist*
- *System Operations Chief*
- *Technology Chief*
- *Weather Officer*

The Playbooks range in length between 9 and 20 pages and essentially follow the same narrative structure. For example, each contains sections on Role Description, Primary Functions, Daily Storm Responsibilities, and Key Considerations (related to the role), among others. DTE issued each Playbook, except for the Singles Strategist, in May 2021, and approved and issued revised versions effective in August 2023. A new Playbook for the Singles Strategist position, responsible for developing an approach to completing or pre-flighting single customer jobs as rapidly as possible, remained under development as of October 2023.

In addition to adopting a centralized ICS, DTE implemented regional ICSs in late 2023 and early 2024 and developed a governance document, EPR-NOP-004, Regional Incident Command Structure, to accompany that roll out. This document outlines goals, expectations, and guidelines, similar to those of the Central ICS.

In addition to the role Playbooks, DTE has also developed an EPR-SWI (Emergency Planning and Response-Standard Work Instruction) Storm Playbook to lay out in time sequence the Company’s approach to managing storm incidents. It takes a conceptual rather than a particular role-defining approach to storm operations. It begins with initial weather and outage forecasts, then moves through weather briefing, the standing up of storm leads, resource notification and activation, initial response and assessment, storm management, demobilization of all response resources, and the development of an After-Action Report. DTE initially developed all but one Playbook in May 2021 and authored the EPR-SWI in November 2023, but without clear indication of formal approval of the 2023 addition.

The Playbooks demonstrate consistent structure and content, but lack comprehensiveness with respect to some important details. For example, a Reports/Documents/Templates section standard in each Playbook, does not either identify or hyperlink expected items, such as contact lists, phone numbers, forms, or checklists. However, the Storm Role Scheduling (“SRS”) application, an internally-developed tool, currently manages the resources assigned to storm roles and does provide contact information. Many Playbooks contain the phrase “Intentionally left blank for future additions.” The lack of detail on contact lists, phone numbers, forms, or checklists does not necessarily evidence their absence or failure to employ them during weather events. Nevertheless, these circumstances do not make important documents readily available, particularly for those not familiar with or knowledgeable about particular roles, responsibilities, or actions. DTE reports the 2023 creation of a Document Governance group currently working to align layouts across the business units (e.g., overhead, underground, system operations). DTE also reports ongoing development of a new storm management tool, Utility Restoration Management Application (“URMA”), that will replace SRS. UMRA will include storm staffing, contact names, phone numbers, tracking rosters, and contractor work during a storm”

Conducting drills and exercises form central elements in ensuring familiarity with the Playbooks and the various roles and responsibilities they detail. The following table provides the dates of exercises undertaken. Bolded dates indicate training for electric outages, while non-bold dates represent training drills associated with cyber, geo-magnetic, and physical disturbances, attacks, or mass blackouts.

DTE Playbook Exercise Summary

Year	Month/Day
2019	May 2 ; October 25; November 13, 14
2020	<i>n/a</i> , Pandemic
2021	August 9-19 ; November 16, 17
2022	March 9; March 15 ; April 4 ; August 29 - September 4 ; September 3; November 9
2023	January 12 ; February 2, 16, 22 - March 7 ; June 20; August 1 ; September 27, 28 ; October 17, 18; November 14, 15;

b. Organization

The central repository for event-related documentation, weather monitoring, internal pre-event communication, certain restoration-related communications, and regular review, analysis and coordination of storm related improvement activities resides in DTE’s EP&R group. This group plays an integral role in the effective functioning of DTE storm preparation and response. A Director reporting up to the Vice President - Operations leads this group, with support from six direct reports who in turn manage 30 additional resources. Staffing for the entire EP&R group totals 37 full-time equivalents and represents a significant evolution in the past few years in size and responsibilities. The EP&R group’s staff levels are very large when compared to those of other electric utilities we have examined. A large staff does not guarantee a high level of restoration performance, but does represent a clear corporate level focus and commitment to storm response and restoration. EP&R evinces strong, experienced leadership at the Director and Manager level, and upper management has voiced unqualified support for the group’s mission.

The six EP&R managers, each reporting to the Director – EP&R and managing groups of four to seven staff, have responsibility for the following functional areas:

- Productivity – Align productivity initiatives and real time metrics
- Public Safety – Enhance Wire Down response strategy and community partnerships
- Damage Assessment – Assess damage and collect damage reports to monitor the impact of severe weather incidents and inform restoration priorities and execution
- Event Management – Take responsibility for the overall life cycle and management of events
- Regional ICS – Implement Regional ICS design with full awareness of restoration progress at the point of activity; Emergency Field Leaders (“EFL”) Management
- Strategy – Take responsibility for long-term strategy and oversee project management, technology, communications, and storm finances.

DTE reports that each group has several major projects or initiatives either under development or recently completed. They include:

- Increasing the numbers of public safety resources available for wire down response (discussed below)
- Enhancing outage prediction modeling
- Standardizing the after action reporting processes
- Improving document governance
- Improving storm estimates and developing a storm matrix
- Implementing the ICS model in the regions
- Increasing the number of damage assessment resources
- Providing accurate real time damage reporting throughout the service territory.

Effective development and implementation of these and other projects by EP&R staff will serve to improve DTE’s restoration performance.

Importantly, from an organizational responsibility perspective, EP&R plays a critical role during an event, in addition to its regular planning and analysis role between weather events. The Incident

Management Team (“IMT”), a subset of EP&R, provides an integral part of storm management and draws on the expertise of numerous EP&R individuals. The IMT Playbook describes this group as serving as advisors and administrators to the Incident Commander, Command and General Staff, and multiple Functional Leads throughout the storm process. The IMT initiates the storm process, sets up the virtual environment for storm management, advises and assists the IC, provides information management and communication support, and prepares executive briefs on storm progress, among other duties.

DTE now has two degreed meteorologists on staff, having just added the second meteorologist in 2024. Two staff meteorologists should provide the ability to not simply interpret near-term weather forecasts but assist in longer-term asset management decisions that reflect an understanding of changing weather patterns on Company-specific infrastructure, particularly those associated with catastrophic storms.

DTE will stand up an Incident Command Center (“ICC”) structure based on storm size. DTE also uses the ICC model at its four regions for localized events within its service territory. The ICC, per federal guidelines, establishes five functional areas for management of incidents: command, operations, planning, logistics, and finance/administration. In addition, key ICC responsibilities include development of event-specific written Incident Action Plans that describe the overall strategy for managing an incident. These plans describe an organized course of events necessary to address all phases of incident control within a specific time. They may include the identification of operational resources and assignments, and attachments that provide direction and other important management information. DTE’s storm response organization reflects this structure and those key storm responsibilities.

2. Pre-Event Planning

Forecasting event type, characteristics, magnitude, timing, and potential impacts should result from an interplay of numerous inputs, from hard data, such as weather parameters, which change constantly, to estimates of the downstream storm impacts and the resources necessary to provide adequate, timely, and effective service restoration. Weather forecasting serves as a foundation for event forecasting, which then supports estimates of storm damage and resource requirements, which then provide the basis for appropriate event classification to scale and mobilize emergency response teams effectively. This report section discusses DTE’s weather services organization and functions and use of third-party outage forecasts to provide estimates of the number of outage events and affected customers for a given event. These planning aspects combine to provide a critical foundation for event classification and resource acquisition.

a. Weather Forecasting

DTE currently contracts with DTN, a well-respected global weather service provider, as its prime source for weather data. DTN also provides DTE with an operational risk-based forecast, an outage prediction model, weather station data collection and storage, and other forecasted and observed weather data. DTE leverages DTN’s weather and outage services with the expertise of two in-house, degreed meteorologists. They interpret and augment DTN data with information from other sources, such as the College of Dupage and government websites. When preparing for adverse weather, DTE meteorologists use the DTN products to create a DTE customized weather and outage forecast. During and after a storm event, DTE references the observed weather data when

communicating the severity of the weather impact. DTE has maintained a contract with DTN for over six years, meets monthly with DTN to discuss any issues or concerns, and indicates satisfaction with the quality of services received.

DTE meteorologists remain on-call 24/7 using a three-person rotation that includes a meteorologist from the Company's environmental group. The meteorologists' main interface involves electric dispatch. Daily workflow includes the preparation of a company specific weather forecast, review of College of Dupage data along with government weather related websites, and development of an Energy Event Index to reflect the degree of severity of predicted or observed weather. They also prepare two-day and five-day weather outlooks and identify potential threats that could cause greater than normal day outages. The five-day forecast serves as the daily weather report. There are also 10-day and 15-day forecasts prepared if requested by the operations staff.

The meteorologists have responsibility for delivering weather briefings to Storm Teams and for making clear the expected weather type, severity, location, and customer impacts. A meteorologist assigned as Weather Officer initiates the storm process by communicating the weather threat to Business Units and the EP&R group with storm responsibilities, triggering a "Weather Briefing & Storm Leads Ramp Up Meeting" as required by outage forecasts." We found these to be well-executed, well-staffed, and consistent with the intended purpose of leveraging in-house expertise to develop company specific weather reports and impact analyses on DTE infrastructure.

Weather forecast accuracy has value to the extent that it provides the basis for credible experiential-based decisions or for objectively modeling projected outages or damages to help in identifying needed resources and expected restoration times from an anticipated event. DTN's outage modeling platform provides that data.

b. Outage Modeling

DTN's proprietary modeling for predicting outage levels for DTE employs a model termed Storm Impact Analytics ("SIA"). DTN has offered SIA, a machine learning model, commercially since July 2022. Outage prediction models can be extremely complex in terms of the variables considered, but typically attempt to reflect a combination of factors such as weather (e.g., wind speed and direction, precipitation, humidity, temperature, ground saturation), tree cover, infrastructure data, and historic outage information, among others. DTE reports that inputs provided to DTN include DTE overhead asset data, outage management system data, and weather parameters. The output of the model supports prediction of outages by hour and location.

DTE meteorologists review DTN outage predictions and amend them as required by current system status, historical outage data considering previously experienced similar weather conditions, DTE's weather forecast, and any other factors considered relevant. DTE's, not DTN's, outage predictions form the basis for operational decisions such as resource acquisition and mobilization timing necessary for responding to weather events. DTE meteorologists, using DTN's model results as one input, convey results to EP&R management for review and discussion. The results form an input to the Crew Allocation Tool to determine numbers of crews required to restore the system within a given time frame.

Predictive accuracy provides an important test for any model. The table below shows the number of outages predicted and actually experienced by DTE for seven classified storms during 2023.

Actual and Predicted Outages (2023)

Storm No.	Actual	DTN Final	Actual/DTN
2023002	1,604	509	3.2
2023003	28,422	2,761*	10.3
2023004	2,086	1,024	2.0
2023005	3,975	231	17.2
2023006	3,203	117	27.4
2023007	7,584	617	12.3
2023008	7,839	618*	12.7

*Includes two waves

In all cases, DTN outage predictions drastically underestimated the number of outages experienced. Actual outages exceeded the number of those predicted by a factor of at least two for all storms and for five storms actual outages exceeded predicted outages by a factor of 10 or more. There may be valid reasons for such inaccuracies, not the least of which is DTN’s model launch in mid-2022. It takes time and data to “learn” the specifics of a company’s system. Further, DTE recently switched OMS platforms, which has created data gaps and anomalies in the learning module. The results shown represent DTN’s “best” estimate of the number of outages, but DTN also provided estimates for 20 percent (*i.e.*, the likelihood that the number of outages will be below that number) and 80 percent (*i.e.*, the likelihood that the number of outages will not exceed that number). Those ranges can be quite large, narrowing the predicted to actual gap at the high end (*i.e.*, 80 percent level).

DTE acknowledges significant issues in modeling accuracy, and work with the provider to make incremental improvements with analysis of each successive set of storm data. With some improvement reported, it appears to remain the case that significant further improvement is needed. DTE is developing an internal outage prediction, Weather Analytic Model (“WAM”) using historical forecast data. The intent is to predict weather outages by day, hour, and location with a three-day lead time.

c. Event Classification and Communication

Prior to 2023 DTE employed an older version of its OMS. The following table summarizes the storm parameters and parameter values, describing the size and estimated impact of each storm severity level.

Previous OMS Storm Parameter Summary

		Level 1	Level 2	Level 3	Level 4	Level 5
		Routine (DO: Blue Sky)	Alert (DO: High Impact Day)	Serious (DO: Storm)	Severe (DO: Catastrophic Storm)	Catastrophic
1	Number of Wire Downs	0-25	25-150	150 - 900	900-2000	>2,000
2	Number of Customers Affected	0-10,000	10,000-25,000	25,000-100,000	100,000-420,000	>420,000
3	Number of Outage Jobs Open	0-150	150-340	340-1,000	1000-1,500	>1,500
4	Life Safety Impact	None	None	Non-life threatening injuries	Multiple life threatening injuries/deaths	Multiple life threatening injuries/death
5	Global ERT Availability Timeframe	< 8 hours	< 16 hours	< 24 hours	< 36 hours	< 48 hours
6	Geographic Impact	Service Center	1 Region	Multiple Regions	Full Service Territory	Statewide
7	Restoration Duration	1 day	2-4 days	3-7 days	5-10 days	> 8 days
8	Restoration Strategy	Order	Hybrid (Order/Circuit)	Circuit	Hybrid (Circuit/Area)	Area
9	Type of Field Resources Required (FTEs)	DECO Crews (Within 1 Region)	DECO Crews (Across 2+ Regions)	DECO Crews and On-System Contractors	DECO Crews, On-and Off-System Contractors	DECO Crews, On-and Off-System Contractors, Mutual Assistance
10	# of Field Resources Required	25-75 DECO Only	50-200 DECO Only	150-500 DECO Only	400-1,500 (DECO, Contract)	>1,500 (DECO, Contract, MA)

Significant definitional aspects for each event Level (except Level 1 – Blue Sky) include:

- Level 2 - High Impact Day: [**ALERT**] The volume of events on screen exceeds a blue-sky day and will require additional resources be dedicated to trouble work out of the gate. Restoration ~1 day
- Level 3 - Small Storm – Large Storm: [**SERIOUS**] The volume of events requires all on premise resources be dedicated to outage response. Various internal and back-office support functions activate to assist with response. Foreign crews might be brought in. Restoration ~<3 days (Goal of 2 days)
- CAT I Storm: [**SEVERE**] 5 percent of DTE’s customer base is out and will require extensive restoration efforts. All hands are on deck and foreign resources will be brought in. Restoration ~3 – 5 days (Goal of 2 days)
- CAT II Storm: [**CATASROPHIC**] 10 percent of DTE’s customer base is out and DTE is required to begin submitting status reports to the MPSC. All internal employees are activated, and executive level ICS is stood up. Restoration ~>5 days (Goal of 3.5 days).

DTE recently made a change to its definition of a “storm,” now considering itself in storm response when the number of outage events on the system exceeds 760 across 200 distinct circuits. The previous definition required an excess of 340 outages across 125 circuits. The increase in the number of outages and circuits defining a “storm” will result in fewer events being so classified. The increase in the threshold numbers of outages and circuits appears to reflect DTE’s increased ability to address more storm conditions without the need to call in outside assistance.

Catastrophic storm classification, per MPSC guidelines, employs threshold numbers of customer outages. DTE characterizes a storm affecting between 5 percent and 10 percent of its customers

(approximately 110,000 and 220,000, respectively) as a Cat 1 storm. The MPSC's definition of a catastrophic storm is one that affects 10 percent or more of a utility's customer base. DTE reports that event counts for its new storm severity level matrix are preliminary and will change as management obtains and analyzes additional data. A new storm severity level matrix under development and expected to be completed in early 2024 appears to have been delayed. The current storm outage event classification (number of outages) follows:

- Small: 760 - 1,006
- Medium: 1,007 - 1,253
- Large: 1,254 – 1,500
- Cat 1: 1,501 – 2,800
- Cat 2: 2,801 and greater.

Storm Classification should be timely, reflect predicted or actual conditions, and undergo wide communication to allow effective marshalling of DTE resources and acquisition of any needed external resources to execute rapid and efficient mobilization and service restoration. Given the importance of event classification to storm response, we gauged the timeliness of storm event classifications by the degree to which they preceded or lagged event starting points. We made a comparison of event start date with the date of initial storm classification for all classified events from 2017 through January 2024 and noted final event classification. During that period, DTE reported and classified 91 events.

Analysis showed no event classified prior to the event start date, and that no event classification ever changed. Such a practice makes classification of little use as a catalyst for pre-event mobilization. This does not mean that internal communications about potential storm size and impact were not widely disseminated prior to an event. The Playbooks describe significant channels for information flow prior to event arrival. However, it does appear that official storm classification has less practical significance as a tool in driving preparation.

d. Resource Acquisition

DTE's event level classifications, as shown above, describe the size and estimated impact of storm severity level, but are currently undergoing modification. The Company notes that the classification dates to before 2023 and before implementation of a new OMS. DTE plans a more detailed breakdown after gathering more data from the new OMS. A Storm Decision Making matrix remains under development but has been delayed past its previously anticipated February 2024 date.

A storm decision matrix can prove particularly useful to resource acquisition by providing guidance to leadership on numbers of field resources (*e.g.*, line and forestry) required to respond to a specific weather event within a targeted time frame, along with other important response characteristics, such as location, customers potentially affected, anticipated outage events, etc. A matrix does not specify what resources must be acquired, instead identifying what may be needed if the storm's impact is as forecast. A matrix imparts a range of responses for consideration in the event that weather and its impacts differ from what is anticipated.

Outage predictions obtained from DTN and internal discussion, review, analysis, and adjustment by staff meteorologists guide decisions about numbers of line crews needed. After determining resource requirements, the Logistics Chief then spearheads resource acquisition. The Chief provides the Incident Commander with analyses of local foreign resource availability, timing to engage them, and whether and when to obtain mutual aid.

DTE secures linemen from several sources, including:

- Its own internal workforce
- Local foreign crews in the service area working on non-DTE projects
- Local baseload crews already working on DTE projects
- Foreign foreign crews not on the property, potentially including mutual assistance resources.

Mutual Assistance resources include those from the Great Lakes Mutual Assistance (“GLMA”) organization. The members of GLMA, a consortium of investor-owned-utilities in the Midwest, cooperate in obtaining and allocating restoration resources.

DTE also has contracts with approximately 30 contractors to augment restoration resources. Further, the Company has Right of First Refusal with a Michigan-based, multi-state lineperson company giving DTE access to 200 line workers before any other utility in the country. Securing such rights in advance through a contracting arrangement is a recognized means for securing availability of resources that become in great demand when large scale events affect a number of wires down business operators simultaneously. Management reports that the combination of non-utility-based contractors, local foreign, and the right of first refusal crews enables DTE to bring in up to 500 crews, consisting of 1,800 FTEs, within 12 to 16 hours. Acquisition of these resources, however, may require an early notification to prevent their release for work elsewhere.

The timing of requests for outside crews can prove critical to restoration duration and efficiency. DTE does not capture acquisition information, making it impossible to assess the quality of its timing decisions. With such information generally available at the time of storm events, it is uncommon to find a lack of retaining it and using it to evaluate performance. Such information can provide important insights about how earlier or later external crew acquisition could have affected restoration activities; *e.g.*, through greater use of pre-staging. Such data can also provide insights into differences in responsiveness of GLMA and contractors to Company requests. Contractor responsiveness has greater importance for larger storms, which often produces competition for outside resources with other regional utilities affected by the same events. The table below shows the number of total external resources employed by year and by storm type for the 2020 through January 2024 period.

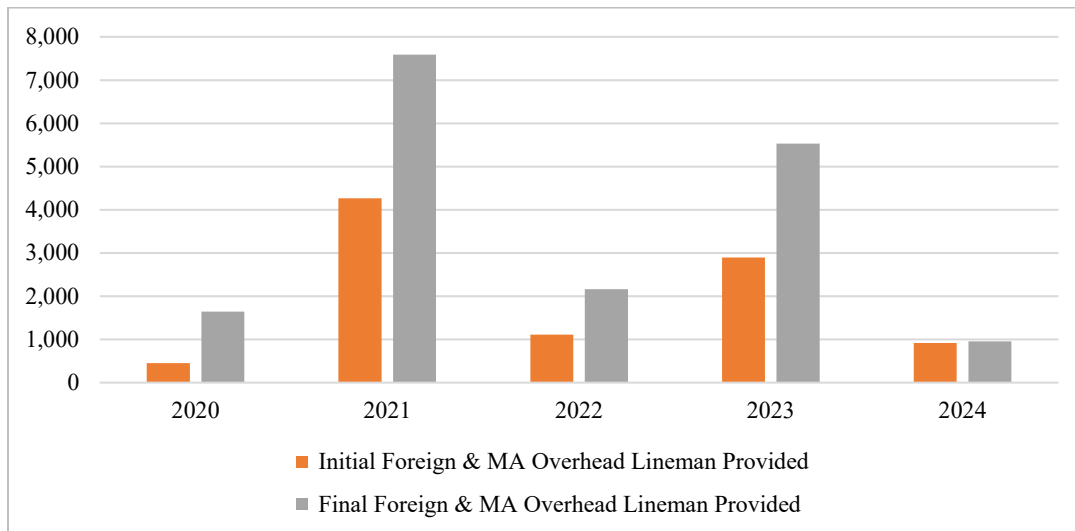
External Resources Employed by Storm Type

Year	CAT-2	CAT-1	Large	Medium	Small	Total
2020		1,647		-	-	1,647
2021	1,612	3,278	975	838	886	7,589
2022	1,293		184	476	211	2,164
2023	4,143	815		493	83	5,534
2024		952				952
Total	7,048	6,692	1,159	1,807	1,180	17,886

Not surprisingly, Cat-2 storms show the largest total concentration of external resources, although Cat-1 storms used nearly as many resources due to a larger number of total events, particularly in 2021 when there were 5 Cat-1 storms but only 1 Cat-2 storm. Total external resources employed by year have varied widely, involving over 7,500 external resources in 2021 and just under 1,650 resources in 2020. The year-to-year variation in the number of external resources used highlights the challenges associated with response preparation generally.

Weather variability largely drives year-to-year variation in external resources used, but one should expect variation between initial and final resources secured to vary in direction. The following table and graph show that during the period 2020 through 2023 period, final external resource levels employed always significantly exceeded those initially acquired. The chart includes partial 2024 data.

Initial and Final External Resources Secured



Year	Foreign & Mutual Assistance OH Lineman		
	Initially	Final	Change
2020	452	1,647	364%
2021	4,268	7,589	178%
2022	1,113	2,164	194%
2023	2,892	5,534	191%
2024	917	952	104%
Total	9,642	17,886	186%

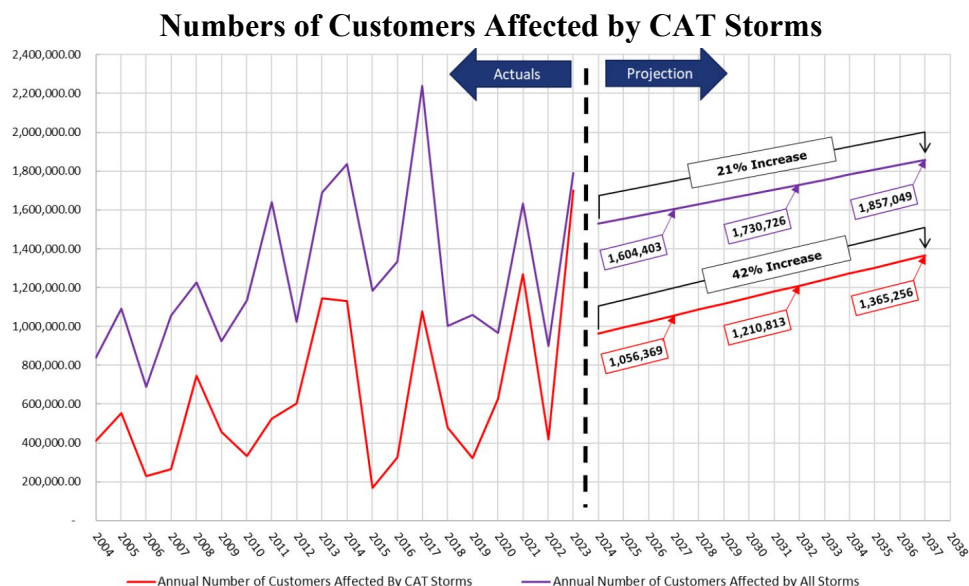
Several reasons may explain why final external resource levels have consistently and significantly exceeded those initially deployed. First, DTE may simply size initial requests for deployment of external resources conservatively, possibly to avoid excessive costs if the number of resources secured exceeds what would have been a lower, and more optimal, resource level. Second, DTE’s outage prediction model, and associated review of a storm’s potential impact, might consistently underestimate the resource level required for effective restoration performance. Third, DTE initial resource requests may roughly match what final resource levels turn out to be, but some portion of those initial resource requests may have proven unavailable in the required time frame due to resource demands elsewhere. This situation is commonly the case in catastrophic storms as resource demands in neighboring utilities become widespread and acquiring resources becomes a drawn-out process. Many utilities, for example, when receiving requests for mutual assistance, will initially hold their restoration resources until they have first assessed impacts and needs on their own service territories. However, as previously noted, lack of data retained by DTE in terms of initial resource requests and initial resources secured does not permit meaningful analysis of its pattern of apparent early underestimation of resources.

3. Event History and Restoration

This Section of the report describes our review of recent storm trends and DTE’s associated restoration performance.

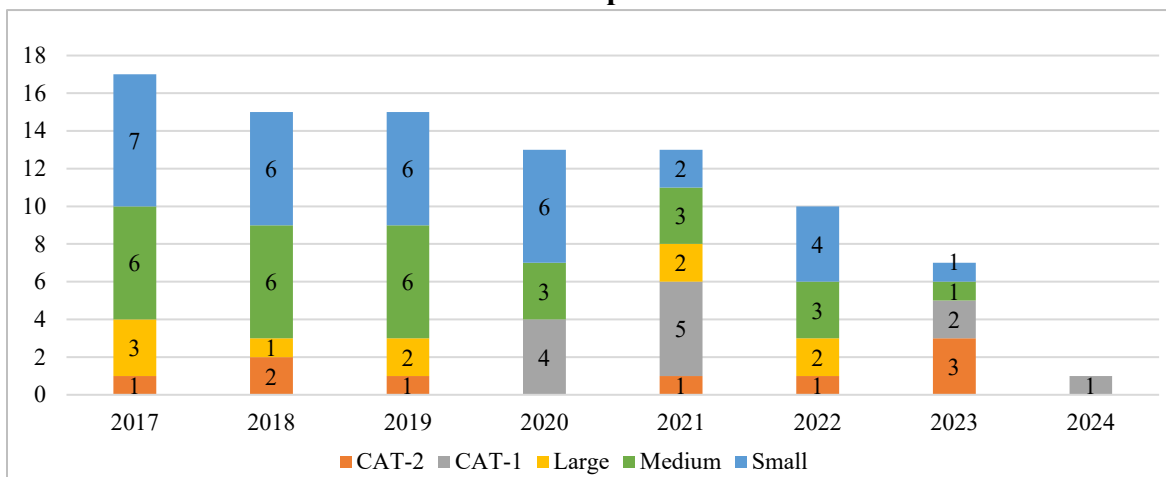
a. Event History

DTE forecasts significant increases in numbers of customers affected by catastrophic storms in the absence of system upgrades, as the next chart from its 2023 DGP illustrates. The Company reports that these DGP-reported numbers are not correct, stating that the 21 percent increase should be 16 percent, and the 42 percent increase should be 29 percent.



The number and severity of storms experienced by DTE have moderated somewhat across the period from 2017 through January 2024. The next table shows uneven, but clearly decreasing number of classified storm events over the period.

Number of Storms per Classification



Year	CAT-2	CAT-1	Large	Medium	Small	Total
2017	1		3	6	7	17
2018	2		1	6	6	15
2019	1		2	6	6	15
2020		4		3	6	13
2021	1	5	2	3	2	13
2022	1		2	3	4	10
2023	3	2		1	1	7
2024		1				1
Total	9	12	10	28	32	91

Notable declines or year over year flatlining in the absolute number of classified events by category has occurred over the past seven years. The number of “Cat 2” storms (those affecting at least 10 percent of the customer base) showed a notable jump in 2023 to three, with those storms affecting over 675,000, 315,000, and 393,000 customers in February/March, July, and August, respectively. Cat 1 storm numbers declined from earlier years, except for 2022, which experienced none. The number of Large storms remained relatively stable. The number of annual storms classified as Medium or Small sized decreased over the period. The recent change in Small storm classification addressed above has likely influenced this last decline.

The relatively small number of data points do not necessarily identify a confirmable trend; however, it is the case that the largest effects from the largest storms have occurred more recently. The greatest challenge lies in the ability to respond to the largest storms, given widespread outages, infrastructure damage, and demand for external resources.

b. Restoration Performance

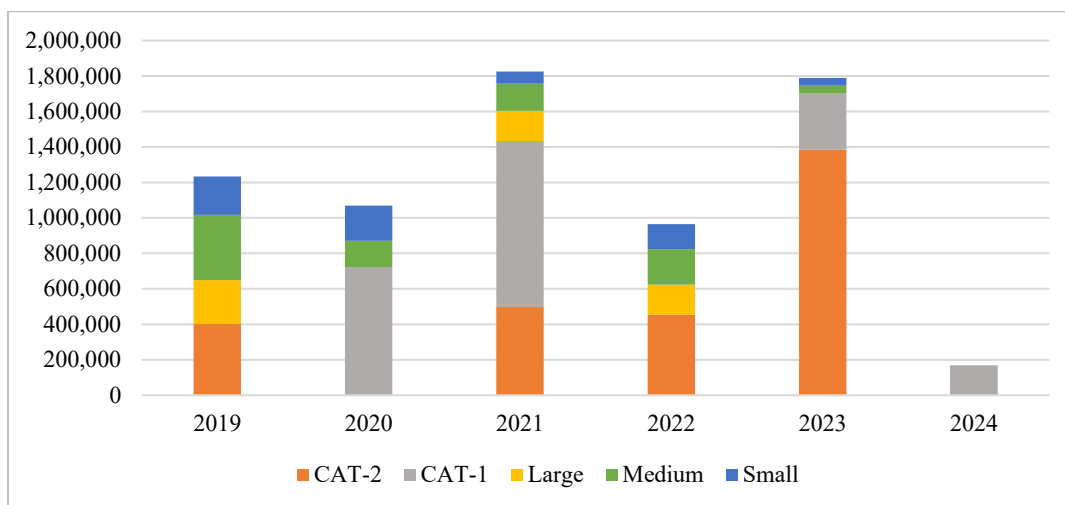
Restoration performance, in terms of the time to restore customers’ service, offers a particularly important metric in assessing the effectiveness of DTE’s storm restoration management. Several elements play a role in this performance, such as the capacity to effectively prepare for events, obtain the required resources to achieve restoration objectives, efficiently support, manage, and

utilize those resources, and maintain clear communication both within the organization and with external stakeholders.

We examined the number of customers affected by each type of classified storm, shown in both tabular and graphic form, below. Interestingly, notable, although likely random, yearly undulations in the total number of affected customers by classified storms have occurred during the period from 2019 through 2023, ranging from a low of approximately 965 thousand in 2022 to a high of 1.79 million in 2023, with those two years unequivocally demonstrating the potential for year over year variability in the impact of weather events. The graph and table also show partial year 2024 data. The data for 2024 captures two storms:

- January 12th, involving 168,292 customers and 3,372 wires down
- June 5th, involving 24, 64,635 customers and 551 wires down.

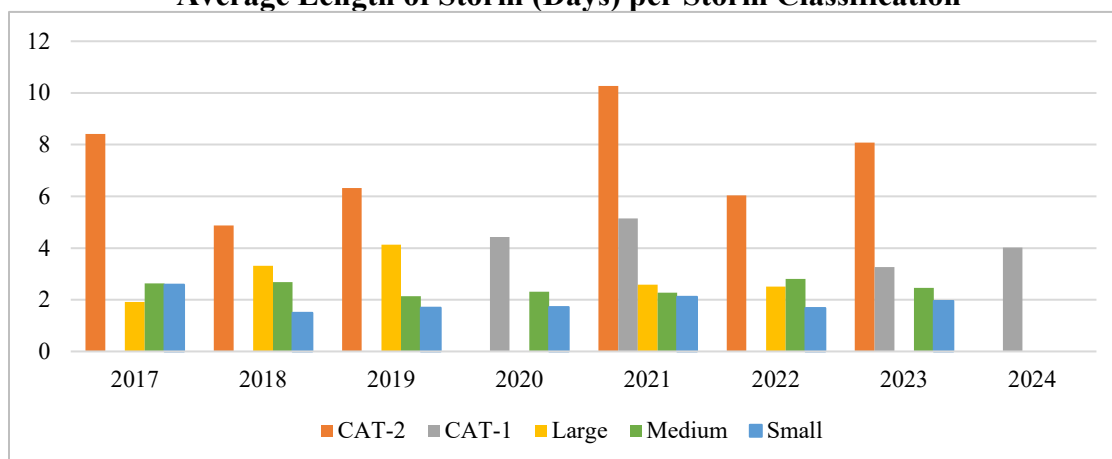
Customers Affected per Storm Classification



Year	CAT-2	CAT-1	Large	Medium	Small	Total
2019	402,441		246,367	368,228	216,336	1,233,372
2020		722,214		148,695	197,672	1,068,581
2021	498,350	935,995	169,191	152,812	69,546	1,825,894
2022	454,069		169,928	200,341	141,055	965,393
2023	1,384,568	315,511		49,934	39,375	1,789,388
2024		168,292				168,292
Total	2,739,428	2,142,012	585,486	920,010	664,344	7,051,280

We examined data measuring the length of time from when DTE declared storms open to when it declared them closed. Note that criteria for these declarations vary across the industry. For example, some utilities define a storm event as closed only upon restoration of the last customer affected. The next table summarizes storm durations for each classified storm by year. We understand DTE to deem storms closed with restoration of the last customer affected. We also understand storm opening to be the date when DTE categorizes the storm.

Average Length of Storm (Days) per Storm Classification



Year	CAT-2	CAT-1	Large	Medium	Small	Average
2017	8.42		1.91	2.63	2.58	2.83
2018	4.88		3.31	2.69	1.50	2.54
2019	6.33		4.13	2.14	1.69	2.50
2020		4.43		2.31	1.72	2.69
2021	10.27	5.14	2.58	2.27	2.11	4.01
2022	6.04		2.51	2.80	1.68	2.62
2023	8.08	3.26		2.46	1.95	5.02
2024		4.02				4.02
Total	7.23	4.50	2.75	2.48	1.89	3.04

The data show a general stability, albeit with some yearly variation, in restoration duration for Small and Medium sized storms. Durations for events classified as Small or Medium for 2022 and 2023 had average restoration durations of 1.82 and 2.63 days, respectively. Large storm durations in 2021 and 2022 averaged 2.55 days, producing an average duration less than that of Medium sized storms. Part of that apparent anomaly can be attributed to the fact that storm classification levels include a reasonably large range of affected customers, thereby potentially skewing results reported by level. For example, a Medium storm (with a range of between 25,000 and 50,000 affected customers) may affect 49,000 customers, while a Large storm (with a range between 50,000 and 1000,000 affected customers) may affect 51,000 customers. Each storm impacts grid infrastructure differently. A violent but localized Medium storm could produce more system damage and a longer duration than a Large storm. Conversely, a Medium storm might affect 25,000 customers and a Large storm might affect 99,000 customers, producing an oppositely skewed effect.

DTE Catastrophic storms (both Cat 1 and Cat 2) showed both the longest and greatest variability in storm duration. A Catastrophic storm’s defining characteristic for DTE (a minimum of 5 or 10 percent of customers affected) strongly influences restoration length, and the unbounded upper limit on customers affected for Cat 2 storms means that category’s events can produce much greater variation in numbers of affected customers, which the results shown above indicate.

DTE did not meet six of the seven MPSC restoration and reliability standards in 2023. The only standard DTE met was to restore a minimum of 90 percent of its customers in 8 hours or less under

normal conditions. DTE reported performance measured by this metric at 93 percent. The *Compliance with Reliability and Restoration Metrics* Section of this Chapter provides additional detail on metric compliance.

In addition to absolute storm duration times and any representative trends, we examined other factors that might influence storm duration. They include the timing and amount of resource acquisition (previously discussed), logistical considerations, and outage communications and systems applications, the latter of which the *Outage Communications* Chapter of this report addresses.

DTE pre-stages crews when conditions warrant, offering an effective means of shortening restoration duration. Pre-staging places the crews and other support resources on standby for the pending event or on site in preparation for the event. DTE has not captured information addressing when it makes calls for outside resources, the number of resources requested, or the number and timing of those initially provided. Consequently, there is not a practicable way to measure with useful precision when the Company secures external resources in relation to event start or magnitude. Were it available, such data might indicate, for example, that management could have obtained and deployed resources earlier, enhancing its ability to shorten restoration duration.

Examination of potential logistical issues identified in the Company's storm After Action Reports ("AARs") showed areas identified for improvement. Those areas appear to have been generally assigned for investigation and resolution and appeared to be adequately addressed. We did not observe any material adverse storm to storm trends in these areas.

4. *Wire Down Process and Performance*

We examined and assessed DTE's wire down processes and performance. Response to "Wire down" conditions forms a critical element in mitigating public safety risks in all conditions, but particularly when response to major storms stresses resources more acutely. Wires that come down and remain energized create major risk and exposure to electrical shock, fire, and potential injury and fatality. Therefore, identifying and responding to wire down events promptly is crucial to ensuring the safety of the community and restoring electrical service efficiently. Additionally, addressing wire down situations quickly also helps prevent potential further damage to infrastructure and minimizes the impact on overall electric utility service. Rapid response and restoration can also minimize complaints, improve the customer experience, and prevent damage to utility reputation.

DTE did not meet the MPSC Wire Down Relief standards in 2023 (*i.e.*, 90% of first responder guarded downed wires relieved within 120 minutes and 180 minutes after notification in metropolitan service areas ("MSAs") and non-MSAs, respectively), which it attributes to the three Cat-2 storms it experienced that year. It did report, however, median wire down response times of approximately 50 minutes and 73 minutes in 2022 and 2023, respectively for non-catastrophic storms (*i.e.*, excluding Cat 1s and Cat 2s).

a. *Processes*

A Public Protection Manager serves as one of six direct reports to the Director of EP&R. The position's responsibilities include leading public protection efforts. Public Protection focuses on

proactive measures to address unconfirmed hazards that include what DTE terms “wiredowns (including Police Fire calls), Service Down No Lights, Service Down Lights Okay.”

Downed wires, however, are not just a storm phenomenon – they can and do occur under ‘blue-sky’ conditions, such as when a vehicle hits a pole. When DTE receives a call, it routes the issue to an Electric Dispatcher who then assigns the job to a line crew or an individual electric first responder, dispatching the selected resources to the downed wire location.

Storm conditions, not surprisingly, present additional challenges due to the greater number of downed wires, the increased potential risk to the public, the need to restore orders of magnitude more customers than under ‘blue sky’ conditions, and the need to identify, contact, and deploy potentially many hundreds of resources to locate, identify and guard the downed wires. The Public Protection Manager oversees the Public Protection (“P2”, or wire down or Secure First) function during storm conditions. P2 roles, depending on storm classification, may include:

- Public Protection Dispatch Coordinators
- Public Protection Dispatch
- Secure First Crews.

Secure First crews consist of DTE trained staff who have completed a structured training program intended to allow them to safely and efficiently execute wire down guard duties. Secure First training includes both instructor-led and web-based training, which precedes entry into a “Mentee” program. Mentees receive Personal Protection Equipment and assignment to a rotation, with mentors assigned at the activation of storms. Mentees must complete 50 field training hours or secure mentor approval to graduate earlier as a Secure First resource. Secure First qualified staff must take regular training to maintain qualified status. DTE augments internal Secure First resources as necessary with contract resources (currently 800, over half of them Secure First trained). The following table shows the total 2023 DTE resource base, by resource type and size, who are available for wire down duty.

Number of Wire Down Resources (FTEs)

DTE Electric Lineman	411
Contract Lineman	628
Secure First	512
Secure First Contractors	800 (460 trained)
Singles Damage Assessment	454
Damage Assessment	201
Underground	117
EFO	129
Service Restoration	185
Total	3,437 (2,922 trained)

Several observations about these numbers are in order. First, wire down call-outs are voluntary so it is not reasonable to assume that all available trained resources will volunteer. Second, trained resources, even if willing, may simply not be available (e.g., vacation, sickness, time-off, childcare) for wire down duty. Third, many of the resource types shown (e.g., line workers) are trained, qualified and best suited for restoration roles, not wire down duty, depending on the

severity of the event. Therefore, while the resource base appears large, it does not reflect what might be available at any given time. Notwithstanding those caveats, the total shown reflects a significant and increasing number of resources available for wire down support duty. For example, in 2021 there were less than 200 trained resources versus the over 1,300 Secure First (DTE and contractors) available currently. The number of contractor wire down responders has grown dramatically from 185 in early 2023 to approximately 800 across 14 companies in 2024 with a goal of reaching 1,000. The use of contractors reflects an innovative and relatively low-cost approach to increasing the resource base, which continues to expand.

The assigned Incident Commander has the responsibility to activate the P2 function. If activated, the P2 Manager in turn activates the appropriate P2 Dispatch Coordinators, who determine the number of P2 Dispatchers required to handle the anticipated wire down workload. The P2 Manager determines the availability of Secure First crews through Everbridge, an internal DTE communications platform, creates crew lists for the P2 Dispatch Coordinators, and increases, as necessary based on the IC's assessment of storm severity, the number of internal Secure First and contractor crews available for dispatch.

The number of wires down drives the number of resources required. Effective response requires more than simply appropriate total resource availability; the timing of that availability and the staging of those resources prove critical as well. The outage modeling that DTE uses includes projected wires down numbers, which has exhibited the same large inaccuracy as has been the case for outages. DTE reports that it has access to forecasted counts of wires down on an hourly basis, broken down by service center area. Recent implementation of a DTE-developed WAM model has largely driven that capability, also increasing the accuracy of weather, outage, and wire down forecasts. The WAM model, unlike the current one used, is being developed internally.

In addition to WAM, DTE uses other technologies to manage its wire down process. One of the more important is its development of Chatbot. Introduced in 2020, the Chatbot program allows P2 crews to use mobile device messaging during storm events. Chatbot allows its users, among other functions, to request wire down job assignments based on current location, receive job information, acknowledge the job, and report ETA. Recent enhancements to the Chatbot include auto prioritization of 4.8 kV wires down over 13.2 kV wires down. DTE reports Chatbot utilization at 100 percent for Public Protection resources. When IT system complications cause a loss of functionality, resource dispatch becomes manual. Such events have occurred on eight occasions since 2021, producing average downtimes of two hours. DTE also reports that it is developing processes to reduce the number of "OK on Arrivals" (meaning no problem found) for customer-reported wires down. All reported wires down require field checks, and "Ok on Arrivals" can account for upwards of 40 percent of reported wires down, resulting in an ineffective use of available staff.

In conjunction with wire down processes, the identification and prioritization of critical and priority customers proceeds under a standardized approach. "DTE utilizes its InService Priority codes to dispatch jobs. The list of these priorities and job types are detailed in SEA Emergency Management Priorities (provided in case no. U-20464 under a non-disclosure agreement with the Commission). The list includes Emergency Health and Safety ("EHS"), hospitals, and schools and other job/customer types." DTE has also created the position of Escalation Manager, whose storm

duties one of its 20 Playbooks outlines. This position focuses on “outage escalations, community needs, and essential services...[including]...warming and cooling centers, pump stations, election polling locations, etc.” The Escalation Manager also addresses issues associated with major and/or essential customers as highlighted by major account managers and can, with the approval of the Incident Commander, increase restoration priority for these customers.

b. Performance

The Company uses results from the DTN’s Storm Impact Analytics (“SIA”) model, internal discussions, experience, and output from its Weather Analytics Model. The accuracy of any model’s predictions can vary significantly from storm to storm and the challenge increases significantly for larger storms.

Field organizational performance primarily drives wire down performance, with numbers ready and able for deployment critical. DTE can draw from a very large pool of trained wire down staff that has increased significantly in 2023 through expansion of Secure First contractors. The next table summarizes the trend in reported number of resources potentially available for wire down duty by year and position from 2019 through 2023.

Number of Wire Down Resources (FTEs)

Type	2019	2020	2021	2022	2023
Contract Lineman	300	300	303	628	628
Contractors			788		
Damage Assessment	157	157	290	201	201
DTE Lineman	409	409	411	411	411
EFO	130	130	129	129	129
EMJ	50	50			
Local 17	14	14			
Local 58	120	120			
Secure First	260	260	790	575	512
Secure First Contractors				150	800
Service Restoration			185	185	185
Single Damage Assessment			587	454	454
Stateline Contractors	10				
Underground	117	117	117	117	117
Wire Guard	1,439	1,439			
Total	3,006	2,996	3,600	2,850	3,437

Notwithstanding the large resource pool, as previously noted, not all wire down call-outs receive an affirmative response. The table below depicts percentages of three categories of Affirmative response for DTE’s Secure First resource base only. Wire down resources operate on a rotational on-call schedule. Those persons on-call are called first and expected to respond except in emergency circumstances. If more resources remain needed after exhausting the on-call resources, those “off rotation” are called. Those off rotation have lesser responsibility to respond than those “on rotation.” The table does not include responses from non-Secure First groups and, the Company has data for only some of the years shown.

Wire Down Response Summary

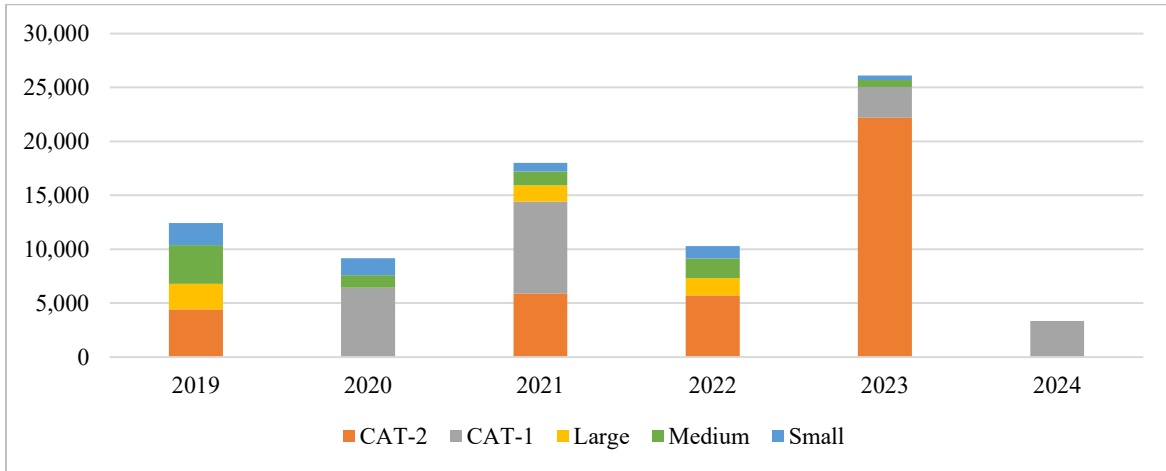
	Affirmative (On Rotation)	Affirmative (Off-Rotation)	Affirmative (All Rotation)
Year	Qualified	Qualified	Overall
2021	54%	43%	45%
2022	56%	46%	47%
2024 YTD	88%	45%	66%

The data represent arithmetic (not weighted) averages of the percentages of Affirmative responses for the classified storms. On Rotation connotes DTE Secure First resources on call during the weather event, Off Rotation represents those resources not on-call, and All Rotation combines the other two categories. The All Rotation percentage does not necessarily reflect the average of On and Off rotation; the number of resources On and Off are not necessarily equivalent.

While incomplete, current year-to-date affirmative responses for On Rotation and All Rotation resources show a marked increase in acceptance rates over 2021 and 2022 levels. That increase reflects the results of steps to improve responsiveness, including automatically placing all employees On Rotation onto the call-out roster. Inclusion was voluntary prior to 2023. DTE has also adopted an auto-generated annual storm support performance goal for all employees. These steps should prove beneficial, but their long-term effectiveness remains an open question. The analysis only reflects DTE Secure First resources.

The chart below shows that wire down resource requirements can vary significantly by storm type and numbers of wires down. The annual total number of wires down due to classified storms varies from year to year with Catastrophic storms not surprisingly driving most of that variation. Certainly, the three 2023 Cat-2 storms that combined to total over 22,000 actual wires down placed great strain on the ability to mount a timely and effective wire down operation. The following graph presents the table’s data in a manner more clearly showing variation in wires down by storm type and the growing impact of catastrophic storms.

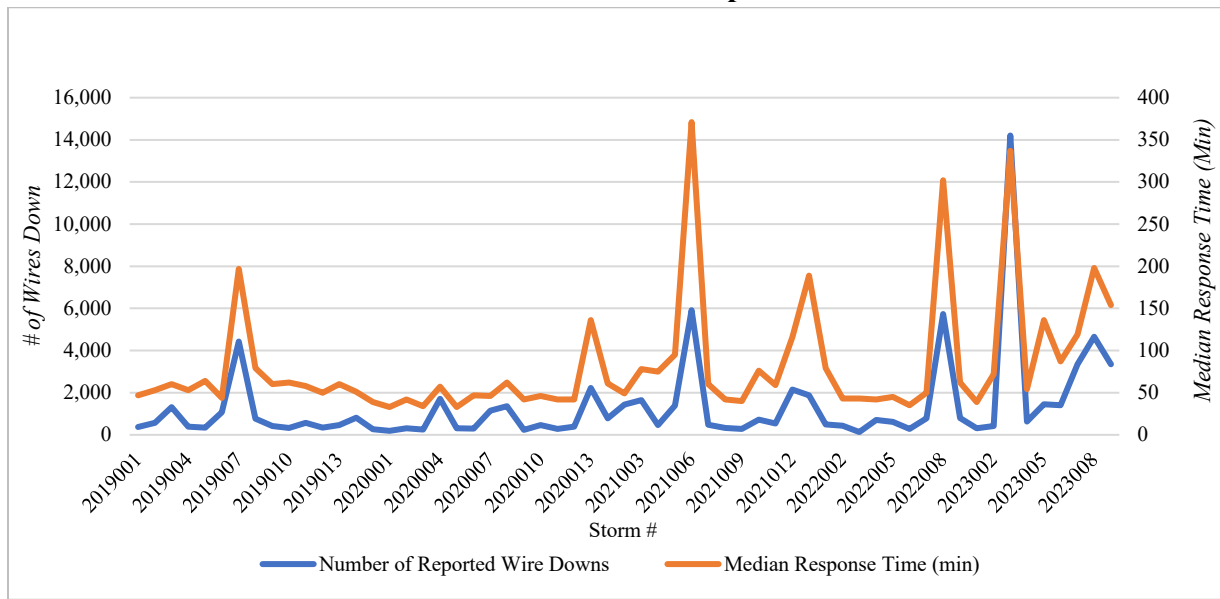
Total Wires Down per Storm Classification



Year	CAT-2	CAT-1	Large	Medium	Small	Total
2019	4,421		2,382	3,569	2,054	12,426
2020		6,424		1,158	1,577	9,159
2021	5,915	8,501	1,507	1,277	822	18,022
2022	5,728		1,588	1,814	1,158	10,288
2023	22,202	2,856		635	425	26,118
2024		3,351				3,351
Total	38,266	21,132	5,477	8,453	6,036	79,364

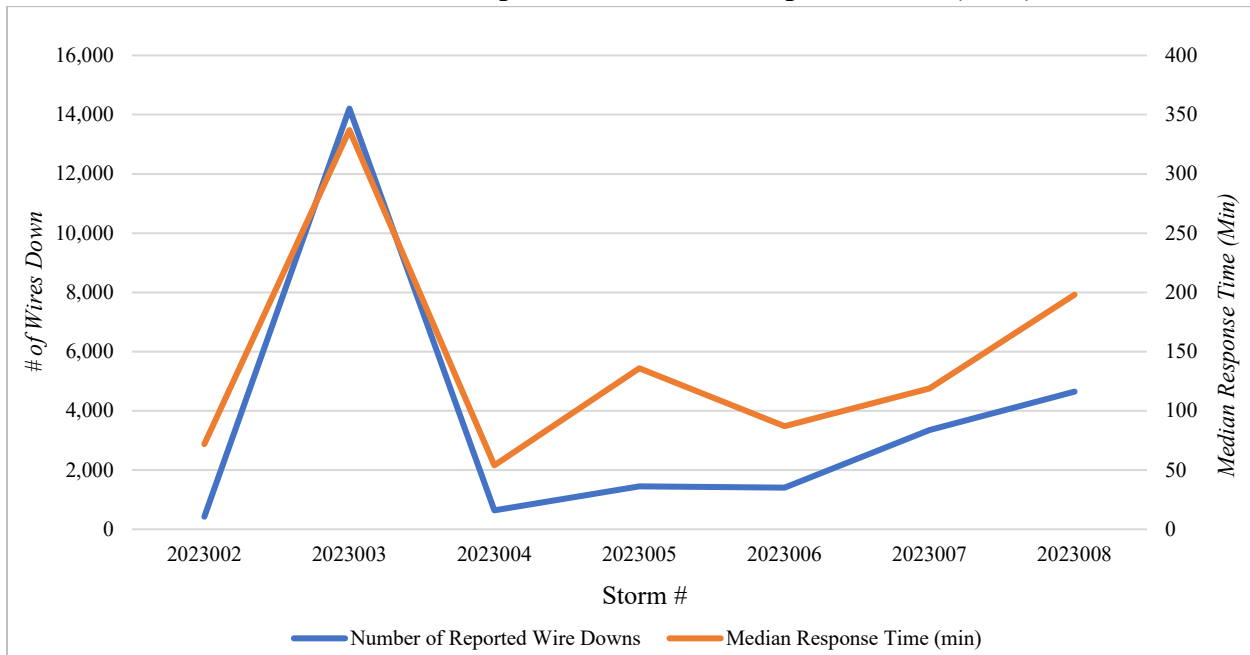
Response time to secure a wire down offers a measure of the effectiveness of DTE’s wire down processes. The next graph shows median response times for wires down versus the number of wires down for all classified storms from 2019 through January 2024. Response times track closely with the numbers of wires down. The weighted average median response time for all storms was approximately 181 minutes, or just over three hours. Excluding Cat 2 storms causes the median response time to fall to approximately 76 minutes, or 1.3 hours. Excluding Cat 1 and Cat 2 storms brings the median response time down to approximately 53 minutes. Cat 1 and Cat 2 storms together produced a median response time of 3.6 hours, demonstrating the great impact that storms of that intensity have on wire down performance.

Wires Down vs Median Response Time



The next chart shows that the February, July and August Cat 2 storms drive overall median response times for 2023. Including all storms for 2023, median response time was approximately 4.1 hours. Excluding the three Cat 2 storms reduces median response time to just over 98 minutes or 1.2 hours, a much better performance but still above DTE’s target of 60 minutes.

of Wires Down Reports vs. Median Response Time (2023)



DTE did not meet either Wire Down relief metric in 2023:

- Relieving 90 percent of first responder (Fire and Police) guarded downed wires within 120 minutes after notification in metropolitan service areas (“MSAs”)

- Relieving 90 percent of first responder guarded downed wires within 180 minutes in non-MSA areas.

We examined the Company’s policy of leaving downed wires marked but unguarded under certain criteria. The next table summarizes DTE’s wire down standby criteria for storms. They apply to electrical facilities whether or not they remain energized. The process calls for electric wires down in high traffic areas and areas like schools and parks to be attended. If the wire is down in a backyard or another location with limited access, it is taped off and left unattended.

Wire Down Standby Criteria

Wire Down Location	All Storms (excl. Catastrophic)	Catastrophic Storms
Wire on or near (<20 feet) a road	Always stand-by	Only stand-by when wire is on or near a major road (mile road)
Wire within 300 feet of a school	Always stand-by until dark	Always stand-by until dark
Wire within 300 feet of a park	Always stand-by until dark and/or public has vacated	Only stand-by parks with high pedestrian traffic
Wire on a structure	Always stand-by	Always stand-by if occupant cannot be notified.
Police Fire	Assessed based on above stand-by criteria	

The stand-by criteria apply to all downed wires. “The process includes dispatching a wire down response team to each reported wire down. The response team dispatched secures the site, installing yellow barrier tape, advising nearby residents of the hazard. This team then reports back on conditions to allow the correct subsequent crew to be dispatched to resolve the downed wire.” If the wire down does not meet the stand-by criteria, Management dispatches the responding team, after it has secured the site, to the next location. If the stand-by criteria are met, the team remains at the site until relieved by field resources. The stand-by process affords DTE wire-down personnel the ability to get to and secure a greater number of wires down more quickly. DTE currently does not deploy enough resources to stand by every downed electric wire until it is repaired. Its distribution system contains a very high percentage of circuits especially prone to remaining energized when down. DTE balances the threat of leaving wires personally unattended against the threat of longer durations to get to other reported wires down by taping and leaving wires down locations not in high traffic areas such as roadways, parks, schools, and heavily used walkways. Management needs to advance efforts to make more wires down guards available to minimize the use of taping off that its current resource constraints has produced.

DTE considers the process mature, having employed it for more than ten years and supported its methods with numerous internal discussions. We found Public Protection leadership knowledgeable, experienced, and articulate in explaining the policy, acknowledging its advantages and disadvantages, and that it considers the process as the most practical means for addressing the need to secure wires down. DTE notes that it stands by or resolves on average 77 percent of wire down events on the first visit, with the remainder posing smaller risk to the public. Management has found this remainder very often located in backyards with limited public access. Standby evaluation allows DTE wire down response teams to quickly move from wiredown-to-wiredown to identify and stand-by those instances of wires down that pose greater risk to the public.”

We found DTE’s policy calling for some downed wires that may yet be energized, to be identified and marked by hazard tape and then left unattended unique in our experience, with DTE acknowledging its rarity. Moreover, we know of no other utility with so large a portion of its system composed of ungrounded 4.8kV distribution circuits. That situation results in the potential for DTE to face a much greater percentage of downed wires that remain energized. These circumstances produce a dilemma, assuming equal resource availability. Requiring guards to remain at all downed wires until relieved leaves more wires down incidents unattended to for longer.

5. Restoration Budgeting

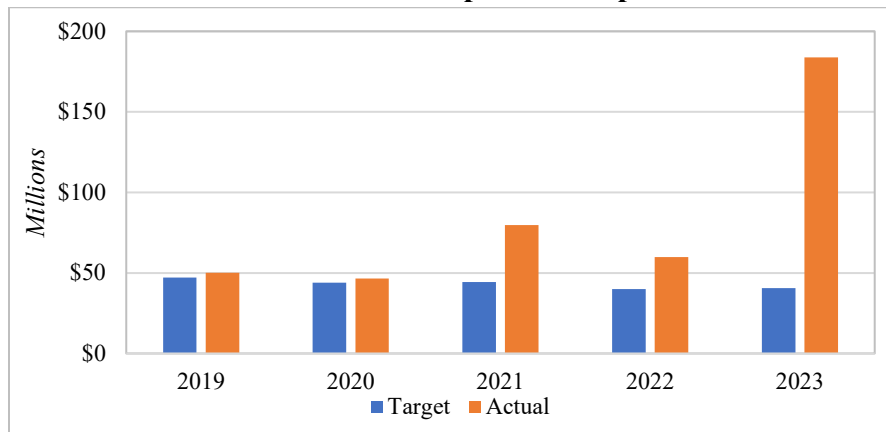
The impact of weather on the magnitude of storm related expenditures makes service restoration costs a large and variable driver of annual O&M expenses and capital investments. We examined the trend of O&M budgets and actual costs associated with service restoration to attempt to discern the leading indicators of future storm costs and to determine whether budget considerations have constrained or impeded past restoration efforts.

Management bases Distribution Operations’ storm budgets (or targets) on historical spend, but also normalizes for prior years’ storm activity. Essentially, DTE averages the previous five-year actual O&M spend and then normalizes that amount for prior years’ storm activity. The normalization process considers the previous 15 years of weather data. Management holds the difference between the actual five-year average spend and the normalized spend for that period in reserve as a weather contingency. Contingency not ultimately needed to offset weather, storm or other risks, can be applied elsewhere.

For example, the 2018 through 2022 average actual O&M storm spend totaled \$57.7 million, supporting a budget of the same amount for 2023. However, the normalized spend for the period (*i.e.*, allowing for weather anomalies during the period) was calculated to be \$40.0 million. The normalization process allowed for the fact that 2021 was an outlier in the number of storm days (50 plus versus an historic average of around 40), as well the fact that the period experienced warmer than normal summer weather. The net result was \$17.7 million held by management as contingency to use if storm related costs turned out to be greater than the normalized amount (*i.e.*, \$40 million), which in fact happened. Storm-related spend in 2023 totaled over \$183 million, far surpassing the budget allowance plus the contingency, due to five catastrophic storms. The February 2023 ice storm proved the largest in Company history in terms of damage. Funds available from other functions and business sectors provide a funding source for restoration work overruns, with reductions in earnings another source if required.

Actual DTE storm-related O&M costs have trended upward since 2019, with actual service restoration costs exceeding budgets or targets every year since 2019 by a range between about 100 to 450 percent, as shown below. The essentially flat “target” of approximately \$40 million per year for the period 2019 through 2023 represents the “normalized” spend for each year over the preceding five-year periods. Contingency amounts would add to those targets.

DTE’s O&M Distribution Operations Spend on Storms



DTE’s Internal Audit group released a review of storm emergent spend in July 2022. The review defined emergent spend as including work required to recover from service interruptions. Management tracks emergent spend in three major categories: Storm, Non-Storm, and Substation Reactive. The audit identified no major risks, but did find four areas of moderate risk, including: lack of processes to measure the performance of out-of-state crews, no finalization of a process to assign work to out-of-state crews, lack of a process to ensure contracts with vendors are finalized before crews are enroute to DTE; and lack of cost visibility in and incorporation into resource planning.

These findings all concerned the management of contract labor, the single most significant cost in storm restoration. Actual contract labor costs during the 2019 through 2023 period represented approximately 48, 58, 62, 74, and 86 percent, respectively, depicting a trend of increasing contract labor costs as a percentage of overall storm spend. We found no indication that management has unduly constrained storm response efforts or limits expenditures because of budget constraints.

6. Compliance with Reliability and Restoration Metrics

We reviewed DTE’s 2023 MPSC Service Quality and Reliability Standards for Electric Utilities R460.731 Annual Report, dated June 14, 2024, filed in compliance with the Commission’s December 20, 2022 Order in MPSC Case No. U-12270. DTE submitted, via its Annual Report, 2023 performance data and potential corrective actions on numerous metrics, such as worst performing circuits by SAIDI and SAIFI, CEMI0 through CEMI10+ statistics, momentary interruption data, and system wide SAIDI, SAIFI and CAIDI information. Performance data provided included the major reliability and restoration metrics, whose results the next table summarizes.

Selected Reliability and Restoration Metric Performance - 2023

Metric	Description	MPSC Standard	DTE 2023 Performance	In Compliance (Y/N)
Wire Down Relief Factor	The percentage of the first responder guarded downed wires that are relieved by an electric utility representative within 120 minutes after notification in MSAs.	90%	78%	N
	The percentage of the first responder guarded downed wires that are relieved by an electric utility representative within 180 minutes after notification in non-MSAs.	90%	85.15%	N
Outage Restoration	Percentage of customers restored in 36 hours or less. [All Conditions]	90%	85.18%	N
	Percentage of customers restored in 8 hours or less [Normal Conditions]	90%	93%	Y
	Percentage of Customers Restored in 24 hours or less [Grey Sky]	90%	81.93%	N
	Percentage of Customers Restored in 48 hours or less [Catastrophic]	90%	81.64%	N
Sustained Interruptions	Percentage of Customers Served Experiencing 4 or more sustained interruptions	6%	13.38%	N

DTE was non-compliant in 2023 under six of the seven restoration and reliability metrics associated with Wire Down Relief factor, Outage Restoration, and Sustained Interruptions. DTE complied only with the metric for restoring customers within eight hours or less under Normal conditions. The Company cited multiple catastrophic storms as the primary contributing factor. DTE experienced three storms categorized as catastrophic under the MPSC’s definition, including an ice storm that started in February and extended into March, and severe thunderstorms in July and August.

A review of DTE data indicates that it experienced a total of 22,202 wires down for the three noted catastrophic storms: 14,205 (64.0 percent) wires down for the February/March storm, 3,349 (15.1 percent) wires down for the July storm, and 4,648 (20.9 percent) wires down in the August storm. Not each wire down requires the same level of time to attend it, and storms have different location, intensity, and wire down demand profile. Nevertheless, the 2023 February/March storm likely had the single greatest impact on DTE’s ability to meet the performance standard.

DTE met the restoration and relief standards in 2022, except for the metric associated with restoration under catastrophic conditions (*i.e.*, 90 percent of customers restored within 60 hours) after having failed to comply in 2021 with five of the six wire down relief and restoration performance metrics then in force. Performance standards tightened in 2023, however, for Wire Down Relief factors, restoration under catastrophic conditions, and the addition of a restoration metric under grey sky conditions.

In addressing corrective measures for reliability and restoration metrics where DTE fell short of standards, the Company outlined several steps being undertaken to address those issues. The Company stated that it is working to increase the number of resources capable of addressing downed wires, to increase the number of dispatch resources, and to enhance technology to optimize dispatch, along with maintaining what it considers to be improved communication and reporting with fire departments. DTE asserts that improved customer restoration performance will result from its plan to modernize and strengthen the grid as part of its 2023 Distribution Grid Plan. Some of the Grid Plan initiatives for which it projects improved performance include grid hardening programs, installation of thousands of reclosers to sectionalize the grid, thereby minimizing, to some degree, customer outages, and continued substation and circuit voltage conversion projects and sub-transmission upgrades.

C. Conclusions

1. Conclusions – ERP Plan and Organization

1. DTE divides storm response protocols and responsibilities among 20 separate Playbooks, which lack some key information. (*See Recommendation #1*)

We found the Playbooks useful for memorializing roles and responsibilities, but less so for communicating some important role-related data, particularly to those unfamiliar with the roles addressed. The Playbooks do not contain or reference sufficient information (*e.g.*, contact lists, checklists, phone numbers, templates, forms) that would allow for single referencing for all relevant data to those not accustomed to a specific role or responsibility. This omission could render storm response less effective under certain conditions. DTE's efforts on Document Governance and implementation of Utility Restoration Management Application to replace Storm Role Scheduling should prove effective in improving the usefulness of storm related protocols and procedures.

2. DTE conducts a sufficient number of annual storm response drills and training exercises.

DTE's storm response drills and exercises, typically of the table-top variety, appear sufficient in number and content such that the use of the Playbooks and implementation of respective storm roles and responsibilities are regularly exercised, with training provided as well.

3. The EP&R organization has effective and engaged leadership that receives sufficient support from senior management.

DTE's EP&R management at both the Director and Manager levels appears knowledgeable, engaged, and enthusiastic in their roles. The high staff levels of the EP&R organization represent

a commitment by senior DTE management to improving the planning, analysis, and management of restoration activities.

2. *Conclusions – Pre-Event Planning*

4. DTE’s two in-house meteorologists provide significant embedded weather-related expertise and function to provide tailored forecasts of weather and potential weather impacts.

Internal meteorological expertise allows a utility more than the ability to take what outside providers, be they commercial entities, government organizations, or academic institutions, supply and convey that data to management. Internal meteorological staffing provides trained resources to interpret data likely to affect the distribution system, apply actual company history with events of a similar nature and offer specific guidance to decision makers about weather conditions and their impacts. In addition to responding to specific events, meteorological expertise can inform asset planning and long-term infrastructure strategy development.

5. Outage modeling results, while limited in number, show a significant level of inaccuracy, thus warranting assessment of other options. (See Recommendation #2)

Predictive accuracy provides an important test of models and their use. For events since DTE began using the model in 2022, outage predictions from its outside provider have severely underestimated the number of outages experienced. Actual outages exceeded the number of those predicted by a factor of at least two for all storms in 2023. For five other storms that year actual outages exceeded predicted outages by a factor of 10 or more.

6. DTE does not use Event Classification as a catalyst for organizational mobilization leading up to a weather event. (See Recommendation #3)

DTE personnel are experienced in storm response. Key personnel we interviewed demonstrated knowledge of their areas of expertise and responsibility. The storm team communicates internally to activate the required resources and processes without focusing on an initial classification of the event. Such an approach, while potentially effective, essentially treats event classification as having little or no value in anticipating or responding to events. This view should change.

Early event classification can catalyze wide and consistent communication to all personnel involved about expectations and associated actions prior to event arrival, increasing the likelihood that all appropriate preparatory steps are taken. Event classification comprises an important process, often more so for large events.

7. DTE has not collected or analyzed data that would better enable it to assess the timeliness and effectiveness of its outside resource acquisition process or to assess the relative responsiveness of the various outside restoration resource pools upon which it depends. (See Recommendation #4)

DTE does undertake processes to acquire outside restoration resources consistent with its evaluation of event impacts. It is not clear how far in advance of event arrival that requests get made to external entities for resources or at what levels. Since such data is not retained it is not

clear if earlier or larger resource requests would have been more effective in prior restoration activities.

3. *Conclusions – Event History and Restoration*

8. The number of total classified weather events has declined in recent years. (See Recommendation #5)

The data show a declining annual number of total classified storms, particularly among those classified as Small and Medium, with the number of Large and Catastrophic (Cat 1 and Cat 2 combined) storms remaining relatively stable. Part of the trend may be attributable to DTE’s recent re-classification of what constitutes a storm, essentially doubling the number of outage events and circuits which must be affected before a weather event meets its “small” storm threshold. This has the obvious effect of reducing the number of “small” storms.

9. DTE’s restoration performance, as measured by average duration of classified storm types, has remained essentially stable, with no marked improvement in recent years. (See Recommendation #5)

DTE has made significant efforts in the past several years to improve storm response, notably by increasing EP&R staff numbers, increasing the capabilities of EP&R management, providing visible senior management support, and undertaking initiatives that should assist in restoration durations. However, the data does not show such improvement. Storm events, generally, show stability in duration.

4. *Conclusions – Wire Down Process and Performance*

10. Public Protection management within EP&R provides strong leadership to the wire down function.

We found Public Protection leadership experienced, knowledgeable, and focused on managing and improving DTE wire down performance. It has introduced useful and effective tools, such as Chatbot, along with an increasingly successful expansion of obtaining and retaining contractor resources to augment internal staff for wire down duty.

11. DTE’s responsiveness to wire down events reflects continued improvement for non-catastrophic storms, but the effects of the largest storms hinder its ability to meet its target of an average median response time of one hour. (See Recommendation #6)

DTE’s average median response time to wire down events for non-catastrophic storms is less than one hour when measured over multiple years, but did exceed one hour in 2023. Durations, however, extend significantly when incorporating the effects of the largest storms. This is directly due to the increased number of wires down in the larger storms and the inability to deploy the requisite number of wire down resources.

12. DTE’s policy of leaving wires down unguarded if they meet certain criteria is very uncommon. (See Recommendation #7)

DTE’s wire down stand-by policy has been in force for over 10 years and reflects a mature process based on considerable deliberation and experience. The policy is intended to achieve the highest

degree of public safety possible while effectively supporting restoration activities. It does, however, explicitly accept the risks associated with having unattended, potentially energized wires down.

5. *Conclusions – Restoration Budgeting*

13. Differences among budgeted, actual five-year average, and DGP planned O&M expenditures are extreme. (See Recommendations #8 and #9)

Actual service restoration costs have exceeded budgets or targets every year since 2019 by a range between 100 to 450 percent. It is not clear how the Company’s five-year average serves as a sound basis for setting budgets or a meaningful marker for sharing restoration costs that vary from five-year averages. It is difficult to see how budgets provided to management do what they should do, which is to establish both a sound resource planning base and a reasonable means for assessing performance effectiveness.

More importantly, weather does not comprise the only variable of import. The increasing ability of the system to withstand weather has equal importance. With billions spent and proposed to be spent to improve system reliability and resiliency, it would be illogical to conclude that the same, or even worse weather will impose the same level of restoration needs as would a system ever weaker and less resilient the further back through the historical “marker” period one goes.

14. We found no indication that DTE has restricted funding during storm restoration.

Once an event has arrived, interviews and data responses are consistent in the position that the necessary funds to effect safe and rapid restoration are made available without apparent restriction. There was no indication that costs – to any material degree – influenced storm related decisions, such as decisions to obtain and deploy additional line crews.

6. *Conclusions- Compliance with Reliability and Restoration*

15. The 2024 report from DTE addressed the filing requirements and identified areas where it failed to comply with MPSC-set standards.

The report addressed the MPSC-required subjects and discussed initiatives and activities to close the gaps identified by DTE. This report chapter provides our analysis of performance, needs, and areas of improvement with respect to wires down and restoration durations.

D. Recommendations

1. *Recommendations – ERP Plan and Organization*

1. Continue to pursue the implementation of the Utility Restoration Management Application. (See Conclusion #1)

EP&R storm planning documentation needs updating and improvement to reflect a more easily accessible and comprehensive information repository for storm related needs, such as contact lists, phone numbers, reporting templates, for example. Having a more accessible, comprehensive and standardized storm response manual(s) will enhance communication and coordination, allowing

for more effective and efficient implementation of storm related protocols and procedures. Future updates and revisions should be approved according to DTE document governance requirements.

2. Recommendations – Pre-Event Planning

2. Accelerate development of the internal outage prediction model. (See Conclusion #5)

Storm impact modeling is an imperfect science, but an improving one. DTE, now with two degreed meteorologists resident in the EP&R organization, can better assure more tailored and accurate outage modeling results through the implementation of the company-specific model (Weather Analytic Model, or “WAM”) being developed. In addition, given the complexities attendant with any outage model, DTE should also evaluate whether a different third-party outage modeling vendor might provide more useful and impactful results or, at a minimum, provide a benchmark for its own model’s results.

3. Classify weather events no later than when a decision is made as to whether available field resources will need to be supplemented and as early as data permits a reasonable assessment of a weather event’s impact. (See Conclusion #6)

The action of event classification should serve as a clear, widely communicated catalyst to groups involved in restoration to be prepared to address the needs associated with the anticipated impacts of the classified event. It needs to comprise more than a post hoc designation of what occurred. In addition, the classification of an event should change, as necessary, after storm arrival, with wide communication reflecting new weather-related developments.

4. Capture and analyze data associated with external resource requests. (See Conclusion #7)

It is difficult, if not impossible, to know with certainty whether earlier and greater resource requests from external entities could have been met and whether such requests would have had a material impact on restoration duration. However, knowing what resources were requested from specific contractors (or mutual assistance), when those requests were made, and what was initially and subsequently provided to DTE would provide a wealth of data that would be useful in preparing for future storm response. In addition, such information should be memorialized and easily retrievable for use by others when, at some point, resource acquisition responsibilities are assumed by others in the organization.

3. Recommendations – Event History and Restoration

5. Continue to emphasize and pursue the numerous internal initiatives led by the EP&R group and conduct an analysis of the impact and cost of securing and deploying earlier external resources. (See Conclusion #8 and #9)

DTE’s EP&R group is pursuing numerous storm related initiatives, including increasing the number of public safety resources available for wire down response, enhancing outage prediction modeling, standardizing the After Action reporting processes, improving document governance, improving storm estimates and developing a storm matrix, and providing more accurate real time damage reporting throughout the service territory. It should also analyze the impact of securing and deploying external resources earlier when preparing for a weather event. Capturing data on when resources were requested, from whom, and in what quantity, both initially and in final total,

would provide valuable information to allow for an analysis of the responsiveness of contractors and the potential impacts from both a cost and restoration impact associated with earlier resource deployment.

4. *Recommendations – Wire Down Process and Performance*

6. Continue efforts to expand available wire down resource base, both internally and externally, along with driving continued improvement in affirmative responses from all available wire down resources (See Conclusion #11)

DTE has made significant strides recently in increasing its wires down contractor resource base along with improving affirmative responses from its own Secure First resource contingent. However, in the largest storms the ability to deploy the necessary resources to reduce wires down response time and leave fewer wires down unguarded will require continued staff augmentation.

7. Perform an analysis of the effects of increased wire down staff on its ability to reduce the number of unguarded wires down during severe weather events. (See Conclusion #12)

DTE's goal of securing 1,000 contract resources for wires down duty is laudable but is likely to still leave a significant percentage of wires down unguarded during storms. DTE estimates unguarded wires currently reflect approximately 23 percent of all downed wires and acknowledges that unguarded downed wires versus guarded wires increase risk to the public, even allowing for strict adherence to its stand-by policy. It could not, however, articulate to what extent that percentage would be reduced by increasing its wires down resource base. Such data would be a useful input into consideration of modifications, if any, of its policy.

5. *Recommendations – Restoration Budgeting*

8. Rebaseline restoration budgeting to produce estimates that fully and realistically consider expected needs. (See Conclusion #13)

Reliance on five-year historical costs to establish restoration budgets should end. Those responsible for managing restoration cannot be held properly accountable for work or costs performance if established budgets are known to be unrealistic, fail to account for weather volatility, include anomalous weather years within the five-year measurement period, or rely on contributions from other parts of the organization to accommodate not just expected, but essentially certain overruns. Regardless of the means by which DTE recovers restoration costs from customers or their amounts, realistic budgeting is essential to sound management of the work and costs involved, just as it is for every other function for which management establishes budgets and to which it manages.

DTE should use normalized weather conditions to generate a reasonable range of expected conditions under at least mild, normal, and extreme weather conditions. Next, DTE should specifically and analytically address how the system's configurations and conditions will change through the DGP period and beyond for areas of investment and other expenditure expected to continue past 2028. This analysis should directly and quantitatively address how system hardness, resiliency, and reliability will interact with assumed weather conditions. In other words, assumptions about restoration work and its costs should not be based on a system that no longer

exists, but on one that has been improving and likely will improve by greater amounts year by year in the future.

Changing estimates of future restoration costs as described will provide a basis for assigning accountability for work and cost performance in a way that has meaning for motivating and evaluating those given accountability and responsibility. It will also enhance management's ability to identify where restoration performance has been strong and where it may warrant improvement at a detailed level. It will also end the effective "socialization" of responsibility for consistent overruns in restoration costs among other functions necessary for utility electricity, gas, and corporate operations. Moreover, it will lay a foundation for addressing in a tangible, meaningful, and more accurate way the rate recovery methods, amounts, and sharing of risks and rewards for what will remain a volatile element of the electricity cost structure, however well managed by the Company.

9. Explore means to balance company and customer interests in addressing highly volatile restoration costs following completion of the preceding recommendation addressing budgeting for storm restoration. (See Conclusion #13)

Most significantly, the use of five years of historical restoration costs as a benchmark for sharing between the Company and customers ignores the fact that the system will steadily respond better as time passes to outages that require material restoration. It should not be taken for granted that escalation and worsening weather will overcome the reliability and resiliency gained by billions of dollars spent over that historical period or the many more that will be spent through the course of the DGP as proposed by DTE. The analytical foundation proposed by the preceding recommendation should provide more realistic underpinnings for the weather, system strength and resiliency, and cost escalation projections that will drive future annual storm restoration costs requirements. Absent those underpinnings, we would not place confidence in concluding that a five-year average cost benchmark balances risks and rewards evenly between the Company and customers.

6. Recommendations - Compliance with Reliability and Restoration Metrics

See the preceding recommendations of this chapter.

Chapter IV – Outage Communications

A. Background

This Section of the report describes and evaluates event communications, both internal and external, before, during, and after a large storm. We focused on planning and preparation while closely examining the customer experience during significant storms in recent years. The report also reviews modifications or enhancements made to improve communications during this period. The audit objectives sought to:

- Determine if customers could reach the utility during recent storms to report outages.
- Assess whether the Company effectively communicated with their customers during storms.
- Understand if the Company kept key emergency and government officials informed during the storms.
- Evaluate if the Company communicated effectively with the public regarding public safety and expected restoration times.

When the power goes out, most customers use their mobile phones to call, text, or visit the utility’s outage website to check the utility’s awareness of the outage and to find out when power will be restored. Storms pose unique challenges for utility customer service organizations. Depending on the size and timing of the storm or outage event, thousands of customers can lose power simultaneously, overwhelming the utility with a surge of contacts. During large outages, the volume of customer inquiries can quickly exceed in-house capacity, especially after-hours and weekends when more customers are at home and fewer customer service representatives (“CSRs”) are available.

Over the years, technology solutions have evolved to help utilities communicate more effectively with customers during large outage events or storms. Self-service options have become widely accepted and preferred by most customers, allowing them to report outages via the web, mobile applications, or phone using Interactive Voice Response (“IVR”) technology. Customers have also embraced outage maps, which most utilities offer to provide information on the extent of an outage and status updates specific to their area, including estimated restoration times. Additional communication channels such as text messaging, social media, and chat provide customers with various ways to interact and receive updates from their electric utility.

Utilities must also be prepared to communicate storm restoration information to the public, as well as local and state officials and community leaders. Even under normal conditions, electric utilities must keep government officials informed about their plans and activities. Utilities share rights-of-way with government services, making their continuous operation essential. Residents, businesses, and institutions expect government officials to stay informed about significant activities, including those related to utilities. Therefore, utilities need a coordinated approach to ensure that government officials know whom to contact with questions or concerns. This need becomes even more critical during major events, as government officials require advance knowledge of potential utility system impacts and need to work closely with utilities to reopen key roads and provide access for emergency operations.

Community relations play a major role during a major storm, especially in keeping state and local officials informed. Community relations officials, often district or division managers, have responsibility for maintaining communication with elected officials, community leaders, and key customers. Before a storm starts, these officials initiate contact to establish communication channels. During the storm, they assist local emergency and governmental agencies by providing critical infrastructure information, offering restoration progress updates, and redirecting resources to address emergency issues and community priorities.

Ongoing education prepares communities for storm restoration needs, practices, and protocols. Hosting community workshops to promote storm response awareness strengthens communication between local officials and the utility and provides an opportunity to gather feedback and understand expectations.

Most utilities leverage technologies such as web portals and mobile applications to facilitate information flow with the community, making it easier for municipal and community representatives to report emergency situations like downed wires blocking roads. Life-threatening situations should always be reported through a dedicated, direct line, but, for less hazardous issues requiring utility attention web-based portals or phone-based interactive applications can provide efficient alternatives.

This section of our audit of DTE’s emergency preparedness programs and processes focuses on communications, specifically in the following areas:

- Call Center and Digital Channels
- Key Accounts
- Corporate Communications
- Community and Government Relations
- Estimated Times of Restoration (“ETRs”)
- Customer Experience.

B. Findings

1. Call Center & Digital Channels

DTE provides customer service through phone, field, and face-to-face interactions to approximately 2.3 million customers in southeast Michigan. Their call center operates 24/7 and employs around 700 people. DTE organizes these employees into various teams, including residential, business, social media, chat, email support, workforce management, performance management, communications, and continuous improvement. Additionally, the Company contracts with an external vendor to supplement customer service support. Since the COVID-19 pandemic, DTE’s call center employees have operated remotely, although the Company makes several hubs available to its CSRs if they lose power during a storm.

The Acting Senior Vice President, Chief Customer Officer, and Chief Information Officer oversees customer service, including the call center, billing, and digital customer channels under normal conditions and during storms and recovery from them.

Customers can report an outage, a downed wire, or check outage status via phone, website, or mobile app. By phone, they can call a toll-free number and use IVR technology for self-service or opt to speak with a CSR. Customers can self-report power outages, check outage status, and view estimated restoration times on the Company’s website or mobile app. Both platforms also offer access to the outage center and outage map, which provide general and detailed outage information, respectively. DTE is also piloting live chat to assist customers visiting the website. The Company offered this live chat functionality during the February 2023 storm for non-emergency related customer transactions only. Additionally, the Company offers text and email notifications for outage updates.

a. Planning and Staffing

DTE’s customer organization works in close coordination with the Public Information Office (“PIO”) and the Communications team during storms and restoration. The customer organization gathers essential information to respond to customer inquiries from the Communications team or through internal Company dashboards, the Customer Relationship Management (“CRM”) system, and the Advanced Distribution Management System (“ADMS”). DTE’s Call Center Storm and Digital Team Playbooks provide detailed guidance for storm response efforts, and management assigns all customer service employees specific storm duty roles.

Storm staffing involves a combination of pre-arranged overtime, volunteer opportunities, and mandatory overtime in critical situations. The Workforce Management team determines the necessary staffing levels before a storm hits. Depending on the anticipated scale of the event, the team first seeks volunteers for overtime and then requests additional support from external vendors. Additionally, other employees within the organization, trained to handle customer calls or respond to social media inquiries, can step in as needed to manage the increased workload during larger storms. The storm activation process includes weather notifications, storm planning calls, and collaboration with the Workforce Management team to assess the storm's impact and timing. Web messaging, apps, and flash messaging managed communication within the call center during storms, with emergency calls given top priority.

Social media teams undergo training, cross-training, and rotation, with quarterly refresher training and skills assessments also employed. The organization has enhanced its social media response capabilities and improved coordination with corporate communications. Management closely monitors the caller experience during storms, with communication channels adjusted and overflow services activated as needed. The Workforce Management team can also reconfigure call center queues to suspend normal business calls, allowing the center to focus exclusively on emergency and outage calls.

Following each major storm, DTE’s Call Center team participates in After-Action Review (“AAR”) exercises for continuous improvement. In 2024, the Call Center formed a Storm Council with employees from all levels and call center functions to meet regularly to review playbooks, lessons learned, and any proposed changes or improvements.

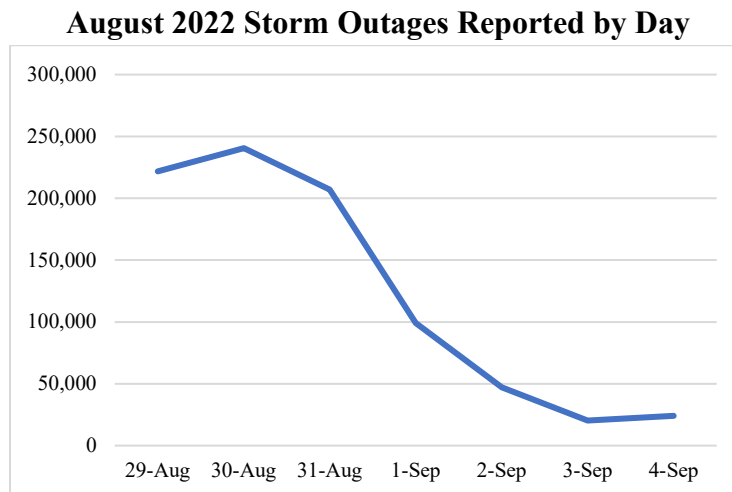
b. Accessibility

To evaluate whether customers could reach the Company during recent storms to report outages, we reviewed call center staffing and performance through three large storms occurring in the past three years. The following table summarizes these storms.

Storm	Category	Type	Customers Affected
August 2022	Cat 2	Windstorms	454,069
February 2023	Cat 2	Ice Storm	675,074
January 2024	Cat 1	Winter Storm	168,292

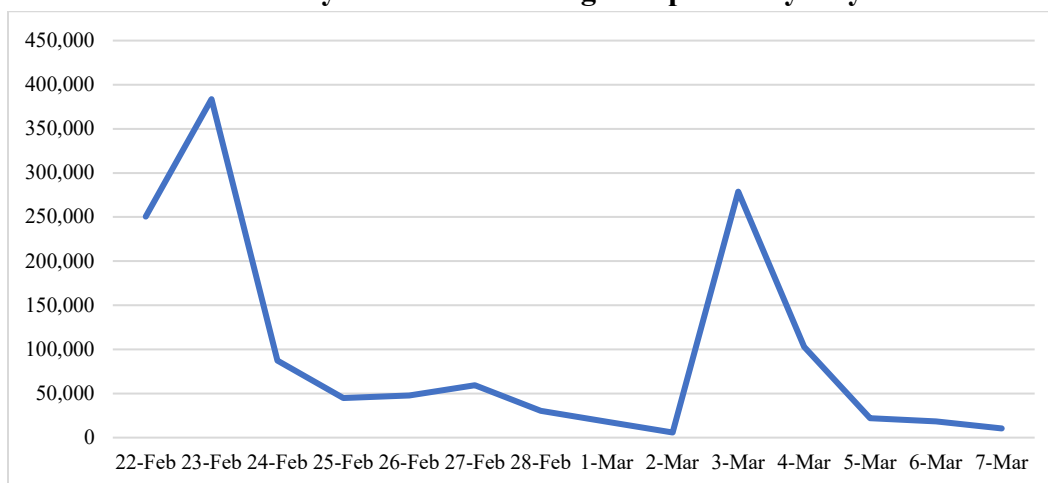
The August 2022 storm started about 4pm on August 29, with restoration completed on September 4th at 5pm. In total, DTE customers reported 859,723 outages. Customers can report outages via phone, website, or mobile app. Additionally, DTE’s smart meters can notify the Company of a power loss through a “last gasp” notification. As a result, overlap in outages reported by customers through these various channels and the notifications received from the AMI system can occur. Additionally, for instances of power restored briefly and then lost, an additional power loss notification may be sent by the smart meter and a customer may submit another power outage from the same location.

The daily outage profile is shown below, with the number of reported outages peaking on August 30th.



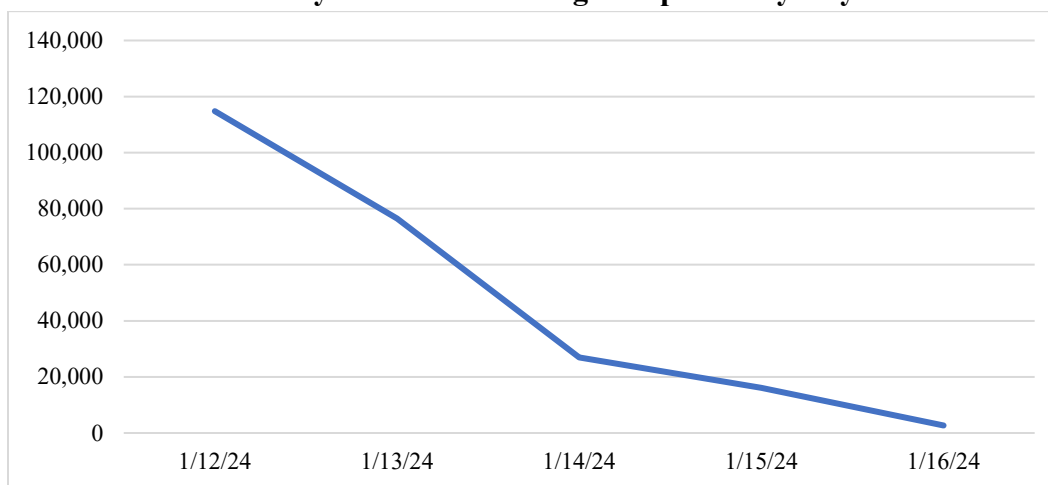
The February 2023 storms began at 3pm on the 22nd and restoration was concluded by 9pm on March 7th. More outages were reported in these storms, 1,359,629 in total. The daily outage profile below shows the impact of each storm, with the number of outages peaking on February 23rd and March 3rd.

February 2023 Storm Outages Reported by Day



The January 2024 storm began at 3pm on January 12th and restoration was concluded four days later on January 16th. Fewer outages were reported in this winter storm, 237,149 in total. The daily outage profile below shows the impact of the storm, with the number of outages peaking on the first day of the storm.

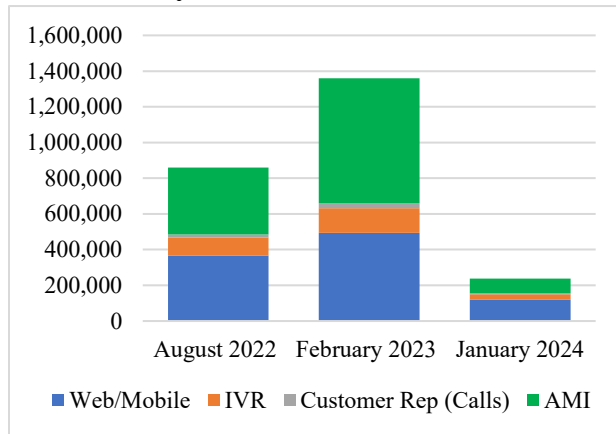
January 2024 Storm Outages Reported by Day



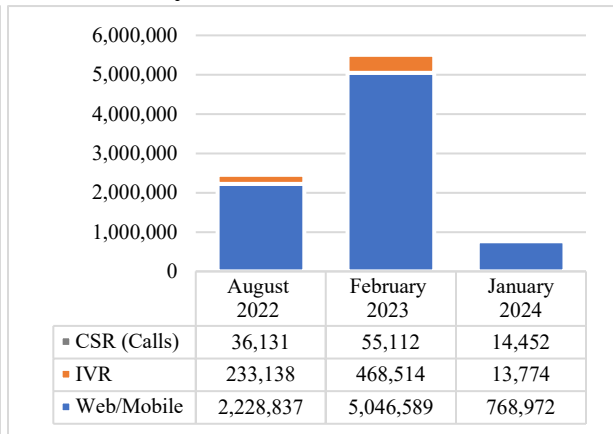
Customers interacted with DTE primarily through the website or mobile app during these three large storms. A smaller number of customers called the Company and interacted with the IVR or CSRs, as demonstrated by the following two charts, which detail outages reported by channel and outage status inquiries received by channel during each of the storms.

AMI-reported outages represented 44 percent of total outages reported in the August 2022 storm, 51 percent in the February 2023 storms, and 34 percent in the January 2024 storm. Customers checking restoration status during both storms overwhelmingly preferred the web/mobile channel (90 percent) for this purpose. Only 8 percent of customers used the automated phone system and 1 percent asked CSRs about status.

Reported Outages by Channel and Storm

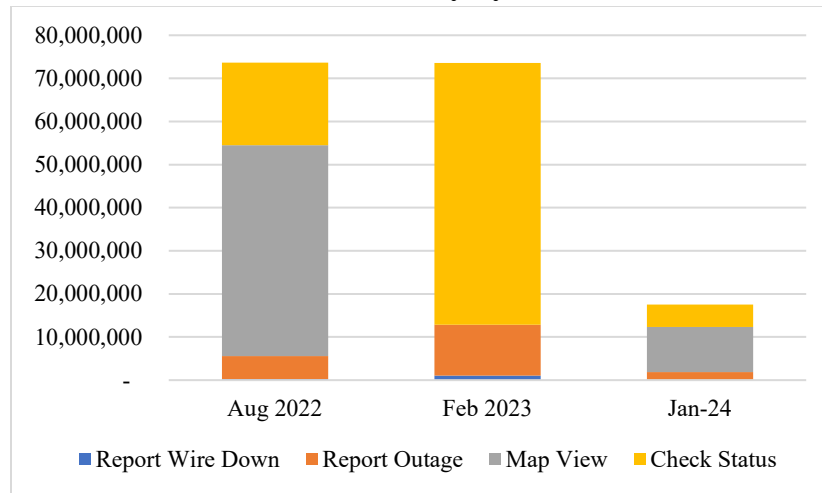


Customer Status Inquiry by Channel and Storm



During both the August 2022 and February 2023 storms, 74 million visits came to DTE’s Outage Center website, despite differences in the magnitude and duration of each. By the arrival of the February 2023 storms, DTE had not yet launched its updated outage map, so customers relied on the “Check Account Status” option on the Outage Center portal for outage status updates. In February 2023, DTE launched a new outage map, however, tracking was not available at the time to provide data on customer visits. In contrast, during the August 2022 storms, customers preferred using the outage map to access outage information. Customers did not access the website as frequently during the January 2024 storm. The chart below depicts Website activity (visits or views) during all three storms.

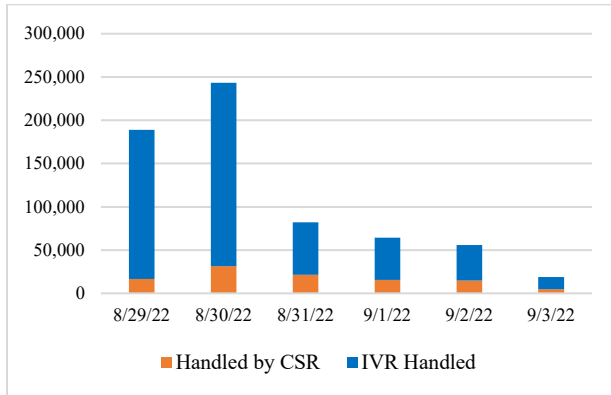
Website Activity by Storm



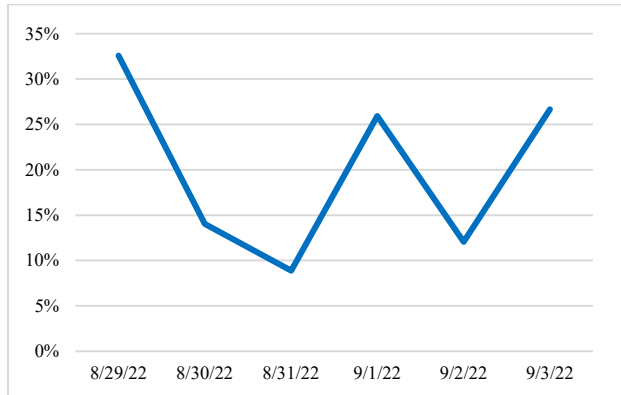
DTE received 677,533 calls during the August 2022 storm, with the automated IVR system handling 81 percent of them. Of the 128,736 calls directed to agents, an average of 19 percent were abandoned. The following two charts illustrate the call volumes managed and the percentage of abandoned calls, with spikes in abandonments occurring on the first, fourth, and sixth days of the storm.

August 2022 Storm Call Summary

Calls Handled



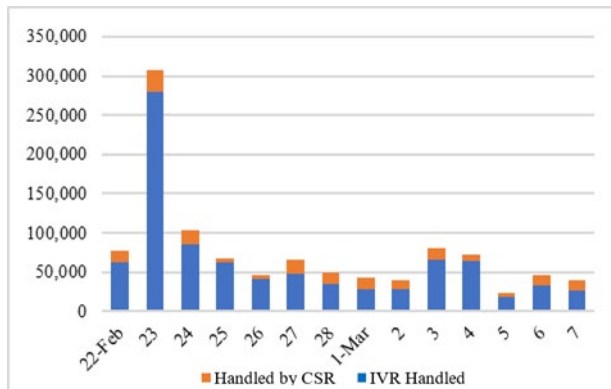
Caller Abandonment Rate



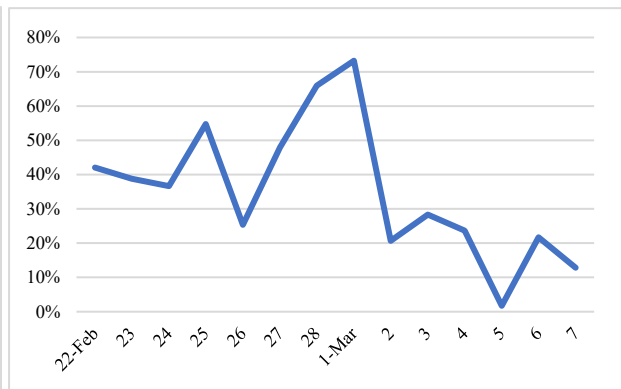
During the February 2023 storms, DTE received 1,200,164 calls of which the automated IVR system handled 73 percent. Of the 325,315 calls offered to agents, on average 44 percent of calls offered to CSRs were abandoned before reaching an agent. Customer wait time averaged 3.5 minutes on February 28th and 4.5 minutes on March 1st. Across the duration of the storm, wait time averaged about one minute and 20 seconds. The next two charts show call volumes handled and the percentage of calls abandoned in. Abandonments spiked on February 25th and March 1st with significantly more callers abandoning during these storms.

February 2023 Storm Call Summary

Calls Handled



Caller Abandonment Rate



DTE added live chat in 2023 (via the Sprinklr platform, a software tool used to respond to social media and chat inquiries), making it available on a limited, pilot basis, for non-emergency inquiries during the February and March 2023 storms. The platform handled only 2,073 inquiries (0.04 percent) during the 2023 storm and fewer, 833 chat inquiries, during the January 2024 storm (0.10 percent).

DTE issued 1.8 million email and text notifications during the August 2022 storm and twice as many during the March 2023 storm. The number of unique customers receiving these email and text notifications also more than doubled from storm to storm. Email and text notifications proved much fewer during the January 2024 storm, with 341,500 emails and 387,200 text notifications issued.

c. High-volume call handling

DTE did not have a high-volume call overflow handling system prior to July 2023. DTE has since contracted with a third-party high-volume overflow service to provide supplemental IVR services when needed, further expanding its capacity to accommodate customers calling during outages.

d. Channel Accessibility and Reliability

DTE’s key outage communications systems and technologies have not performed well under load during major events, as the following table shows. More than 50 storm-related technology incidents have occurred in the years 2021 through 2023, affecting customers, stakeholders, and Company resources that rely on these technologies for outage communications. Incidents include issues reported to Information Technology support personnel regarding use of DTE’s customer-facing technologies such as the website, Outage Center, Outage Map, IVR, Mobile App, SMS Text channel other digital channels. Incidents also include delays in sending information or notifications and issues encountered with any of the internal systems supporting operations including the Outage Management System, ADMS, or SAP Customer System.

Storm-Related Technology Incidents

Storm	SAP	OMS	Web	Outage Map	Mobile App	Phones	IVR	Emerg Phones	Police/Fire Web App
6/21/21			X		X				
6/25/21	X		X		X				
7/6/21	X		X		X				
7/24/21			X			X		X	
8/9/21	X	X	X		X	X	X	X	
9/21/21		X							
3/31/22			X	X	X				
4/14/22			X		X				
5/21/22			X	X		X	X	X	
6/15/22			X		X				
8/3/22			X		X		X		
8/29/22	X		X	X	X	X	X	X	
2/22/23	X		X		X	X	X	X	
7/20/23	X	X							
8/23/23			X						X
Total	6	3	13	3	10	5	5	5	1

The following five sub-sections of this Chapter, organized by major technology or system, expand on many of the technology incidents noted in the above chart.

e. Telephony Performance

DTE’s call center telephony has proven to be a significant source of problems, particularly during the storms of 2021 and 2022, when capacity issues affected caller experiences. On August 11, 2021, customers encountered problems for three hours. Some could not connect to the toll-free number, while others were put on hold when attempting to use the automated IVR system. Call volumes during this storm exceeded the call center’s capacity. The phone system became overloaded again during the August 2022 storms, leading to various hardware failures. From August 29th until 2 p.m. on August 30th, customers experienced intermittent difficulties connecting with the Company or suffered from degraded call quality once connected.

During the February 22nd and 23rd, 2023 storms, DTE’s customer information system became overwhelmed by requests coming in through digital channels. The IVR could not process self-service requests. Most customers during this time were transferred directly to a CSR. On February 23rd, from 9 a.m. to 9:30 p.m., customers intermittently experienced “dead air” (call answered but no sound heard), and the IVR was not responding. Similar issues occurred on February 24th from 1 p.m. to 9:30 p.m. Additionally, from February 23rd to 24th, the Avaya call management system indicated that calls remained in queues even after customers had abandoned them, making it difficult to manage staffing levels.

DTE has made significant improvements to address these capacity issues. In April 2023, the Company replaced its analog phone lines with digital VOIP/SIP lines and digitized call-handling hardware with virtual servers. This allowed the Company to increase contact center phone capacity and redundancy between its two data centers. Additionally, in July 2023, it contracted with a third-party high-volume overflow service to manage surges in call volume, like those experienced during the February 2023 storms allowing customers to self-serve. In August 2023, the Company increased phone center capacity from 1,440 lines to 5,000 by deploying VOIP/SIP and virtual servers. Following the deployment, DTE conducted stress testing of the new telephony equipment, simulating more than 4,750 simultaneous calls through the new infrastructure, resulting in only a 1.2 percent failure rate. No major issues have been reported since deployment of the new telephony system.

DTE plans to replace the underlying technology supporting its current IVR platform later in 2024 to improve performance and the customer experience.

f. Website & Mobile App Performance

In November 2019, DTE migrated its website and outage map to the cloud to enhance the customer experience and improve reliability. Despite this upgrade, these platforms continued to face issues during storms. During the 2021 summer storms, customers frequently had trouble logging into the website and mobile app, sometimes for hours or even days. Customers also encountered errors, slow performance, and transaction failures due to increased load on the SAP CRM and network configuration problems. DTE resolved these issues in July 2021.

Customers experienced intermittent errors in 2022 while reporting outages or downed wires and checking outage status. To address these problems, the Company implemented WISMO, an order tracking system, in March 2022 to intake customer requests (report and check status) across the website, mobile app, and IVR channels to align messaging accordingly.

However, during the August 2022 storms, the outage map become intermittently unavailable for eight hours on August 29th. To address this issue, DTE implemented a new cloud-based map solution in February 2023. During the February 2023 winter storm, the outage map was available to customers, however, customers reported confusion with the new interface and the outage information presented on the map. Additionally, during the February 2023 storm, customers could not complete transactions on the website or mobile app for several hours on February 22nd, because the volume of traffic coming from the digital channel interfaces overwhelmed SAP.

Police and Fire users experienced slow response or an unresponsive web app when trying to view open orders from August 23rd to 26th of 2023, which was resolved during the storm.

g. SAP System Performance

CSRs experienced degraded performance of the SAP CRM system during outages occurring in summer of 2021. CSRs again encountered CRM performance degradation during the August 2022 storms due to high volumes of outage transactions received from OPI (Web), Nuance (IVR), and C4C (representatives). These issues apparently remained unresolved, as digital channel requests overwhelmed the SAP system in the February 2023 storms.

During the summer of 2021, CSRs occasionally experienced degraded performance of the SAP CRM system during outages. These issues recurred during the August 2022 storms, when the high volume of outage transactions from OPI (Web), Nuance (IVR), and C4C (representatives) again caused CRM performance degradation. During the February 2023 storms, the SAP system became overwhelmed by requests coming in through digital channels, and the IVR could not process self-service requests, forcing customers to be transferred to the queue for live agent assistance.

h. ADMS & OMS Performance

Other systems supporting outage restoration and communications have experienced issues during recent major storms. During the 2021 storm events, DTE reported slow performance of the Outage Management System for four hours. During the August 2022 storms, customers did not receive ETRs in notifications for a day due to a back-end infrastructure issue.

DTE deployed its new ADMS system in early February 2023, just before the February ice storms. In effect, the storms served as the “stress test” for the new system. Issues with the new ADMS systems caused the provision of inaccurate estimate information to customers during the storms. The system also canceled reported outages, lengthening actual outage duration.

OMS processing delays occurred from July 20th through the 23rd of 2023, resulting in slow performance of outage analysis function. DTE has since replaced the InService OPI application with OSI and tuned the system to address the performance issues.

i. Stress and Load Testing

DTE conducted various application and channel specific stress and load testing during 2021, 2022, and 2023, but had not conducted integrated outage stress testing prior to the 2022 and 2023 storms. Unfortunately for customers, large storms appear to have been DTE’s default load and stress test of outage communications systems and technologies.

A third-party technology assessment conducted following the 2023 storms recommended end-to-end stress testing to simulate surge events and identify breakpoints, noting DTE’s inability simulate storm load end-to-end and current integrated load testing practiced in pockets.

Testing that DTE conducted in the summer of 2023 on outage systems and technology resiliency, simulated a storm producing one million outages and using data from the February 2023 storm. Transactions tested included outage reports received by IVR, Web, Contact Center, and AMI and

outage status requests received by IVR, Web, and Contact Center. The test focused on issues identified in the February 2023 storm including:

- Response times for creating an outage and getting status
- Time required to create an interaction record on CRM
- Receiving and processing updates from ADMS
- CR&B performance during batch processing.

Management executed separate simulation tests on six days during May and June, as DTE investigated and attempted to resolve the above issues and others encountered during the testing.

DTE also conducted telephony-focused stress tests in August 2023 to test the new VOIP/SIP (Voice-Over-Internet-Protocol/Session Interaction Protocol) and virtual servers implemented to address issues experienced in prior storms. The enhancement increased the number of available lines into the contact center from 1,440 to 5,000. Testing that simulated more than 4,750 simultaneous calls through the telephone system produced a 1.2 percent failure rate.

2. Key Accounts

DTE's Major Account Service ("MAS") group supports 6,000 of DTE's largest customers. DTE assigns approximately 60 employees to one of six account segments: industrial accounts, governmental and institutional accounts (hospitals, universities, waste water, and K-12 schools), process manufacturing, national accounts, real estate/entertainment venues and developers, and business energy accounts (smaller schools and manufacturing facilities).

MAS representatives serve as the single-point-of-contact during day-to-day operations and during storms and restoration. Industrial and Commercial Primary customers have a dedicated line directly into the System Operation Center ("SOC"). MAS sets up and staffs a dedicated phone center during larger events to supplement direct support of key accounts. Additionally, data analysts support the center to gather data needed to expedite and coordinate storm restoration for these customers with the Storm Incident Command System ("ICS") team. Many of the customers for these accounts own their electrical equipment. DTE dispatches a primary service representative to the site to support customers until the issues can be addressed.

MAS maintains its own guiding documents, standard work instructions, to define support roles for day-to-day and during a storm. DTE activates the MAS storm team following a series of mobilization calls and weather predictions. Management assigns each MAS employee to one of three rotating teams that supports key accounts during a storm. The MAS team actively participates in the ICS process during larger events.

The MAS team works to set priorities for restoration during daily ICS calls. For instance, the Daily Plan prioritizes schools and MAS reaches out at 5:00am to let school administrators know which schools are scheduled to come back in service, so they can notify parents in a timely manner. A dedicated line was established for schools in 2022 to enhance support and feedback to the MAS team. DTE also sends targeted communications to schools about any nearby wire-down situations.

Account representatives have responsibility for correctly coding each major account in the system to ensure proper storm restoration priority. Accounts receive NACS codes and critical customers a specific code as well. For instance, water, sewer, hospitals, fire and police stations get a critical customer code.

The MAS team has access to ADMS and Company dashboards to facilitate account updates concerning restoration status. MAS also conducts follow-up calls for all key accounts to confirm that power has been restored and the business has resumed operations.

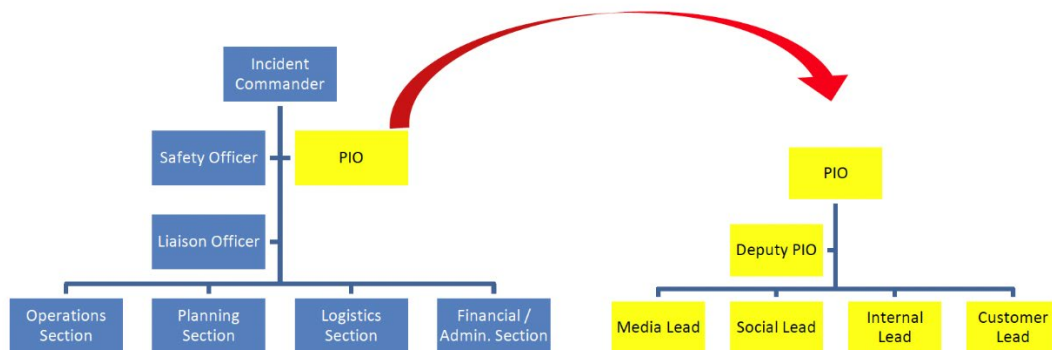
3. Corporate Communications

During a major storm, a utility’s Corporate Communications department must effectively disseminate storm restoration status information to stakeholders that include state and local government officials, large industrial customers, the media, employees, and customers. Communications should deliver the same central messages to the press, mayors, legislators, city officials, and the next customer calling into the call center. This section examines how DTE communicates with stakeholders during a large storm or outage.

a. Crisis Communications and Storm Communication Planning

DTE staffs its Corporate Communications organization with approximately 50 employees who all have storm support roles. Two documents provide guidance for the Communications teams during a major event: DTE’s Enterprise Crisis Communications Guide and the Storm Communications Playbook. The Crisis Communications Guide provides communications guidance for more than 30 different crisis scenarios, including electric outages, and outlines specific responsibilities of the PIO and other roles in supporting communications during incident response. DTE’s Vice President or Director of Corporate Communications typically serve as the Storm Communications Director while the Manager of DO Communications serves as the PIO. Prior to storm activation, the PIO participates in pre-storm command meetings to review weather and predicted impact. Upon activation, the PIO reports directly to the Incident Commander, sits in the Command Center, and is involved in all ICS meetings. The following diagram details the core communications team reporting to PIO during an ICS event. Additional communications support teams include Digital, Advertising, Multimedia and Design.

Communications Response Team Reporting to PIO



DTE’s Storm Communications Playbook, deployed in 2022, details communications tactics for pre-storm, during storm, and post-storm use and includes checklists, templates, examples, and planned messaging based on the impact and type of event. The Playbook continues to evolve based on lessons learned from recent storms, benchmarking, and changes in the process.

Leading up to a storm, DTE posts safety messaging to Nextdoor, Facebook, and X and may send emails to customers with safety information depending on storm severity. The next illustrations provide examples of safety-related storm social media posts from the February 2023 storm.

Examples of Media Posts - February 2023 Storm



During the storm, written advisories or press conferences provide updates to the media and other stakeholders. Media updates and releases take account of information gathered from the ICS commander, Emergency Planning & Response (“EP&R”) director or District Operations (“DO”) leadership. DTE’s Communication Storm Director and the PIO review the draft media advisory for content and accuracy. The EP&R director or DO leadership distribute media advisories following review and approval by the Storm ICS commander.

Corporate Communications maintains a log of all communications issued internally and externally during a storm. Corporate Communications measures and monitors customer sentiment, engagement in social media and website and mobile app content as well as media and interview requests, in order to understand how communications are being received,

b. Social Media

DTE offers and manages several social media channels, among them Facebook, X, LinkedIn, Nextdoor, and Instagram. DTE uses the Sprinklr platform to monitor and manage social media

inquiries and posts. The Social Media team and Customer Care have access to this platform. Customer Service staffs up a “social care team” to respond to social media inquiries and posts during storms and restoration. Additionally, a social media triage process exists to guide any required investigation and follow-up. The Communications Social Media team has responsibility for public posts, generally proactive messaging; the Customer Care Social Media team handles monitoring and response.

A team of DTE leaders serve as social media ambassadors and monitor social media conversations in private groups and communities. Ambassadors refer any issues and inquiries to the social media team for investigation and follow-up. Additionally, all DTE employees are empowered to report any issues they see on their personal social media channels to the triage team. DTE created a new storm role, Ambassador Specialist, in July 2023 to provide pre-approved messaging to ambassadors in affected communities with safety, outage, and restoration information.

c. Internal Storm Communications

DTE uses mass email communications to alert employees to incoming storms and to prepare for storm duties. Depending upon the size of the storm, the communications team provides regular updates to executives summarizing communications efforts, including proactive media outreach, media interviews and coverage, social media sentiments, community outreach, and provides ready access to a chronological report of all internal and external storm communications to-date, advertising, media recaps, coverage, and sentiment.

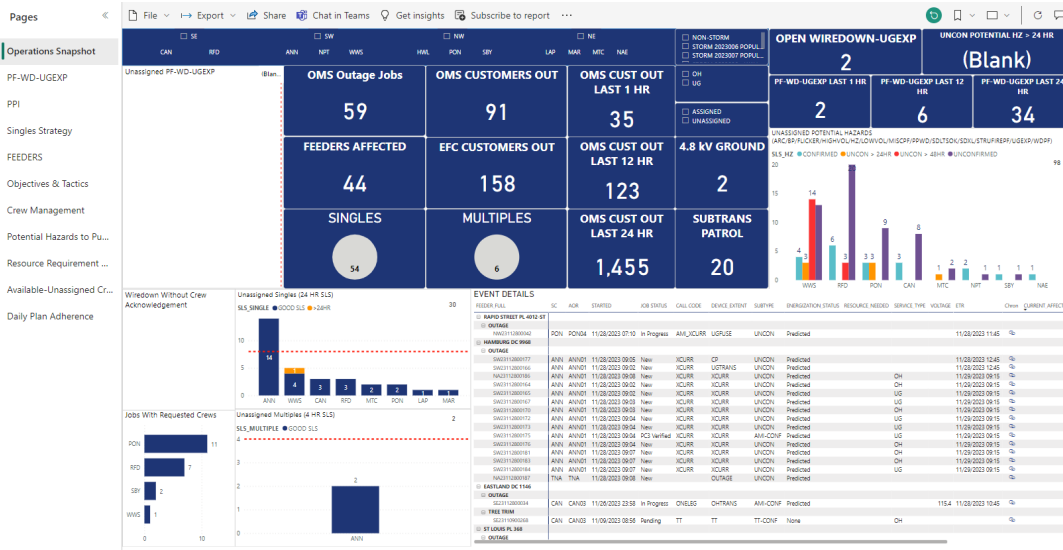
Management engages customer service and field operations leadership in ICS scheduled communications and ramp-up. Three daily meetings of all storm personnel, using a prescribed template to facilitate discussion, occur. The Incident Commander, in cooperation with the director of EP&R, updates senior executives daily via email regarding restoration efforts, progress, and issues.

Contact Center Storm Coordinator, Corporate Communications, Strategy team, and Workforce Management work together to update CSRs through Microsoft Teams, Storm Pulse Checks, Newsflashes, and emails.

The Everbridge alert system supports communication with all field and active storm duty personnel during an event to keep them informed of status and changes in conditions.

A storm dashboard available to employees (illustrated immediately below) provides real-time updates on affected customers, system condition, restoration status, and other storm-related operations.

DTE Storm Dashboard Summary



4. Government & Community Relations

This section summarizes our examination of how DTE communicates and supports first responders, state/local government officials and emergency managers in the hours leading up to an anticipated storm as well as during and after the storm.

a. Municipal and Government Communications

Corporate and Government Affairs (“CGA”) manages relationships with representatives at all levels of government. The group plays a major role in communications during outages or storms by coordinating with emergency command centers to provide effective assistance. The team includes three directors responsible for federal, state, and regional (local) government affairs, respectively. DTE has dedicated six full-time Regional Affairs managers to the electric service area and, when needed, two additional managers to gas service territories, to support communication to local governments during outages. The CGA Team works through Regional Affairs Managers to maintain consistent communication with local, state, and federal stakeholders, including elected officials, supported by specialists and community relations representatives.

During events, CGA proactively reaches out to key stakeholders to provide frequent updates on outages and restoration efforts. Twice daily during storms, CGA sends email updates containing information about impact, progress, safety messaging, and relevant contact details, including instructions for reporting issues and locations of heating/cooling centers. This outreach seeks to keep ensures those affected informed until situation resolution.

Regional Relations Managers operate on a rotating on-call schedule for storm coordination and participate in ICS command calls and planning sessions. During catastrophic events, an on-call Regional Relations Manager is stationed in the ICS command center to expedite escalations and coordinate communications.

CGA also participates in the After-Action Report process after major outages to identify strengths and opportunities for improvement. DTE piloted once such improvement in the January 2024

winter storm, conducting a virtual town hall for elected leaders. DTE found it well-received and that it facilitated early discussion and triage.

CGA employees also engage in training exercises with local counties, including FEMA training, and participate in periodic EP&R training sessions. Beyond storm events, CGA maintains regular communication with stakeholders about rate cases and infrastructure improvements, providing customized updates on tree trimming, pole-top maintenance, and automation deployment to keep municipalities informed and engaged.

b. Emergency Responders, Fire, Police Communications

In 2018, DTE created a 24/7 dedicated emergency line for first responders and other emergency personnel. Additionally, DTE updated call center scripting to improve the communications process for those emergency personnel contacting the center. The Company meets quarterly with a representative group of fire chiefs to continue to gather input and feedback.

DTE also offers a self-service web/mobile portal for emergency responders, police, and fire personnel to report outages and electric hazards. This app allows users to report issues and view a dashboard of open incidents. At the end of 2023, DTE enhanced the mobile portal to facilitate the reporting of wires down with a “pin drop.” First responders can also upload photos and provide additional information about the event and its impact on the public through this app.

c. Regulatory Communications

DTE’s Regulatory Affairs organization has responsibility for the relationship with the Michigan Public Service Commission and the Department of Energy. The Regulatory Affairs Client Liaison supports the Commission during a large storm, as needed, and validates submittal of any required DOE reporting. DTE’s ICS Storm Leader communicates directly with Commission Staff through twice-daily storm status emails at 8am and 3pm. MPSC Staff will be invited to attend internal DTE state-wide storm calls for any events affecting more than 50,000 customers. Regulatory Affairs works closely with the ICS team to answer any MPSC questions, provide requested data, and walk through the material with staff as needed. The Formal Regulatory Affairs team reviews and delivers storm reports and all other required reporting to the MPSC.

Approximately 23 employees staff the Regulatory Affairs organization. Management assigns those not directly supporting the MPSC or DOE during an event to other storm duties, such as wire down monitor roles.

d. Communications with Medical Needs Customers

DTE runs a query of its Customer System ahead of a storm to identify customers with special medical needs and customers older than 80 years old. DTE assigns a group of employees prior to the storm to begin calling these customers to understand their needs should they lose power. Following loss of power, DTE provides wellness checks, heating and cooling centers, and will move customers if necessary. Management has also trained customer service representatives to assist medical needs customers. DTE has booked hotel rooms and provided back-up generators to these customers in prior storms.

5. Estimated Times of Restoration

Customers need a basis for planning during extended service disruptions, even though precise service restoration estimates may not always be possible. Clear communication of the best available information plays a major role in effective event response. Major storms disrupt not only utility services but also local and sometimes state government services and private businesses. Realistic service restoration estimates enable governments and communities to plan and respond effectively.

Traditionally, customers reported service interruptions by calling the Company. Advances in technology have expanded communication options, including Interactive Voice Response, texting, websites, and mobile apps, enabling two-way communications. These tools allow customers to report outages and receive specific restoration status information. Many utilities now provide outage maps on their websites and offer self-service outage reporting. Advanced metering technologies and distribution automation help identify customer locations without power, reducing reliance on customer reports.

When a customer reports an outage through any available channel, the contact creates a trouble ticket in the outage management or advanced distribution management system. These systems automate trouble ticket management, expediting the identification and restoration process. Damage assessment plays a crucial role in planning and executing restoration, allowing utilities to develop ETRs. Timely and accurate ETRs keep customers and stakeholders informed. However, inaccurate ETRs can lead to customer frustration and mistrust, making it imperative to provide and update accurate restoration estimates.

This Section of the report contains the findings, analysis, and detailed descriptions of the systems and processes that support the establishment, updating, and communicating of ETRs during an outage event. The audit's objectives included a review of DTE's ETR process and performance in recent storms for:

- Establishing ETRs
- Updating ETRs as changes in circumstances develop
- Communicating ETRs initially and on an ongoing basis to customers and local officials.

a. ETR Establishment

The ADMS automatically generates restoration estimates once the outage event is reported by a customer under blue sky conditions, based on predefined rules and historical performance. During a storm, the Estimates Team generates storm ETRs by integrating damage assessment, weather data, and historical performance. DTE used field input and the outage management system to trigger power restored communications to customers prior to 2022. In March 2022, DTE began to use information from customer meters to confirm that power had been restored prior to sending communications, improving messaging accuracy.

However, customers expressed frustration with ETR communications during major storms in 2021, 2022, and 2023. Voice of the customer research revealed ongoing issues with inaccurate notifications, multiple incorrect ETRs for the same outage, and expired or inconsistent ETRs, leading to customer dissatisfaction.

Following August 2021 storms, DTE initiated a First Estimate Accuracy cross-functional project initiative to develop an improved ETR process and more accurate ETRs. The team introduced the Global Estimate as a key part of its storm estimation strategy in 2022. These estimates sought to provide customers with a general timeline based on storm severity for power restoration (e.g., 90 percent restored by end of Friday). The initiative also clarified ETR process roles and expectations. DTE introduced a Regional ETR Coordinator role in 2023, with responsibility for monitoring and updating of storm outages assigned to restoration crews. This storm role coordinates with the Central Estimate Manager (“CEM”), which has responsibility for the Company-wide storm estimate strategy (and any ETRs for jobs that have not be assigned a crew). Additionally, the team has worked closely with Regional Operations to increase visibility and importance of ETR accuracy in daily operations calls.

Informed by feedback and expectations gathered from customer focus groups and industry benchmarking, the team developed guiding principles and set objectives to enhance communication of customer storm restoration estimates, including:

- Generation of global estimates within one hour after the weather clears or by 6am based on the overall scale of severity of storm damage (damage multiplier), weather data, and historical storm restoration performance
- Development of outage-specific estimates for each outage event at the individual premises location (house or business).
 - Generation of these estimates in storm situations will occur within four to six hours after the weather clears
 - During a storm, customers will only see the date of estimated restoration, not the expected time (Friday, January 3rd)
 - In blue-sky conditions, customers experiencing outages will see both time and date of estimated restoration.
- Consideration of an ETR produced during a storm as accurate if the customer receives a single estimate and the customer is restored on the day provided in the ETR.
- Consideration of an ETR produced during blue-sky conditions as accurate when the customer received a single estimate, DTE restored service to the customer no earlier than 3 hours before or 10 minutes after the estimated time.

Following the 2023 storms, DTE further enhanced the use of AMI meter status to reduce inaccurate status communications when power is restored temporarily or partially, further improving outage status messaging accuracy.

b. ETR Monitoring and Performance

DTE measures ETR performance using the First Estimate Accuracy metric, which it calculates as the percentage of customers receiving an accurate estimate divided by the percentage of customers receiving an estimate. Management deems an ETR as accurate if it represents the only estimate given to the customer and the Company restores the customer’s power on the same day as the estimate indicates.

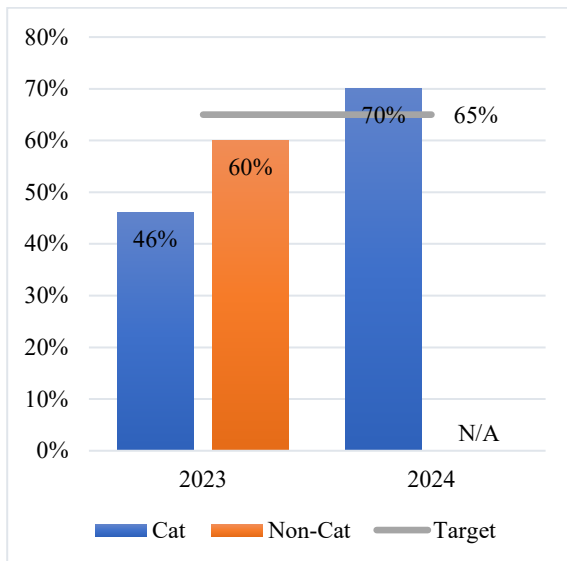
DTE developed a First Estimate Accuracy Dashboard (illustrated immediately below), used to track ETR performance.

DTE First Estimate Accuracy Dashboard



In 2024, the First Estimate Accuracy for catastrophic storms stands at 70 percent, marking a notable 24 percent improvement compared to 2023. However, the 2024 data reflects performance for one storm so far, whereas the 2023 data covers six storms, including five classified as catastrophic. The next table summarizes individual storm performance for First Estimate Accuracy.

First Estimate Accuracy – Storms



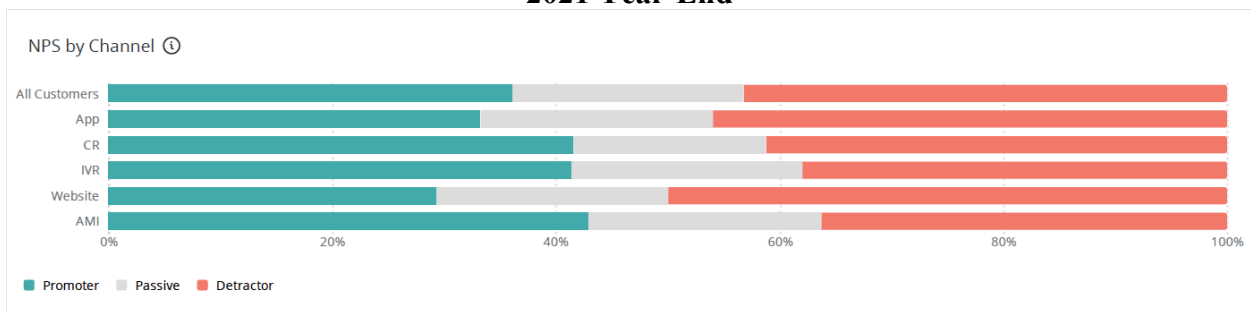
Storm	Type	Date	First Estimate Accuracy
2023003	CAT	2/22/23	44%
2023004	Non-CAT	3/25/23	70%
2023005	CAT	6/25/23	66%
2023006	CAT	7/20/23	49%
2023007	CAT	7/26/23	42%
2023008	CAT	8/23/23	46%
2024001	CAT	1/12/24	70%

C. Conclusions

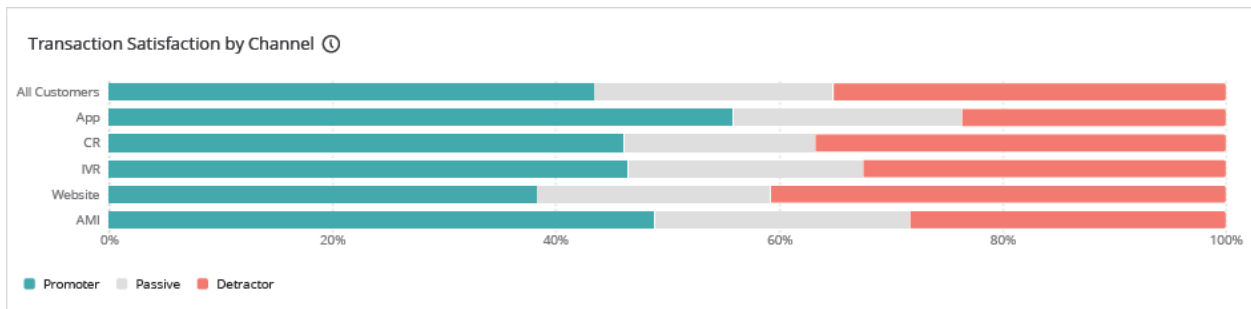
1. DTE’s customer outage experience has suffered during recent large storms. (See Recommendation #1)

DTE’s Customer Outage Experience, as reported by customers in surveys and customer complaints, has suffered in recent years, especially during large and catastrophic storms. DTE’s Net Promotor Score (“NPS”), a popular survey method used to measure customer satisfaction levels, and Outage Transaction Satisfaction, as reported through customer surveys, show a negative trend in years 2021 and 2023, when DTE experienced catastrophic level storms. NPS calculations subtract the percent of detractors or dissatisfied customers from the percentage of promoters or satisfied (neutral responses are not included). Negative NPS scores indicate that the percentage of dissatisfied customers is larger than the percentage of satisfied customers responding to outage experience surveys. The next chart shows DTE’s year-end NPS scores for the last three years for all customers and for all digital channels.

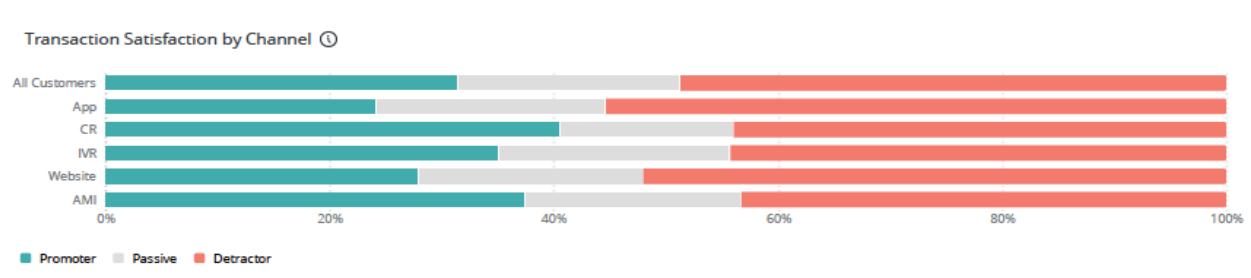
**Net Promotor Score by Channel for Outage Transaction Experience
2021 Year-End**



2022 Year-End



2023 Year-End

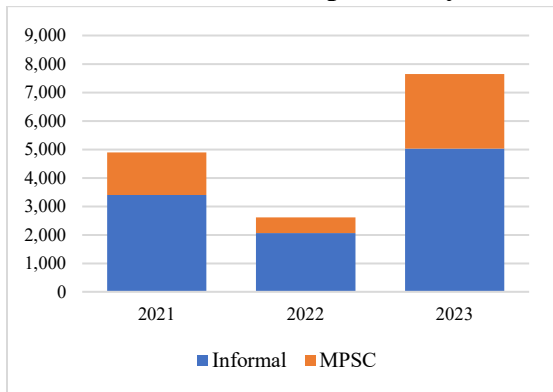


The top three issues identified by customers surveyed over past three years were outage duration, frequency, and accuracy of ETRs.

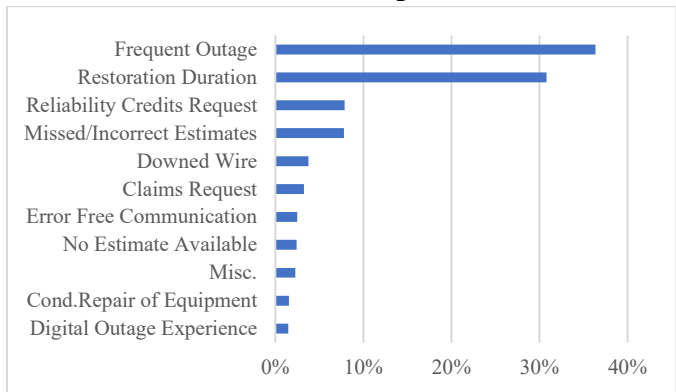
In 2023 DTE witnessed a significant rise in storm-related customer complaints with customers identifying concerns primarily with the frequency of outages, followed by the duration of outages.

Customer Complaint Summary

Storm-Related Complaints by Channel



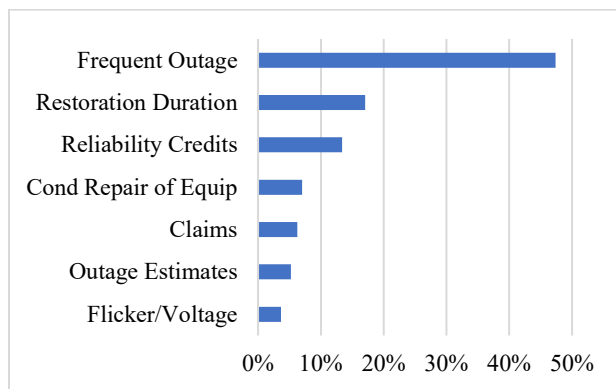
2023 Storms Complaint Reasons



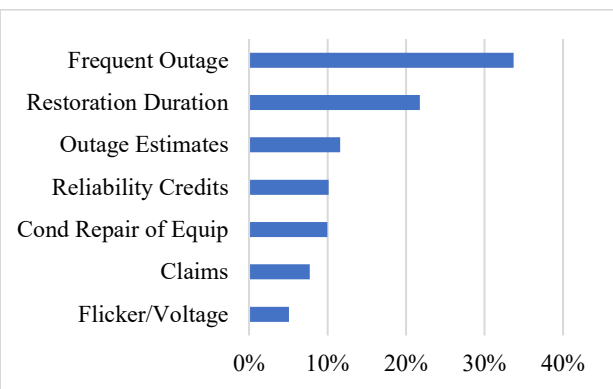
Customer complaints received during 2021 also largely related to outage frequency and duration, while complaints received in 2022 related to restoration duration and outage estimates.

Storm Complaint Reasons

2021 Storms



2022 Storms



DTE’s Voice of the Customer research conducted during this period indicated ongoing issues with inaccurate ETRs, missing or delayed notifications, multiple ETRs for the same outage, as well as expired ETRs, as factors that contributed to customer dissatisfaction during large storms.

2. DTE’s Community Relations has a sound organizational foundation, good planning processes, and continues to enhance its efforts to keep stakeholders informed of outage response efforts.

DTE employees serving as community relations representatives work in that role day-to-day and during storms. Regional managers routinely reach out to local and county emergency personnel on priorities and communications needs. As a result, during a storm or large outage event, DTE personnel already have familiarity with the territory and established relationships with local elected and emergency management personnel. This familiarity provides a solid foundation for communications between the Company and key stakeholders.

The challenges faced in recent storms have prompted the team to leverage feedback and lessons learned to enhance and reinforce protocols to ensure officials and community leaders receive timely, comprehensive alerts and updates, with information about expected weather, preparations, and DTE contacts. For instance, in the January 2024 storms, CGA conducted multiple briefings for more than 40 municipal leaders to discuss storm damage and restoration progress. DTE expects to continue this practice during large storms going forward.

DTE also created a web and mobile portal for emergency responders, police, and fire to report outages and hazards and provided a dashboard for viewing open incidents. DTE enhanced the portal in late 2023 to enable “pin drops” to more easily report downed wires and other hazards. Additionally, first responders can also upload photos and provide other information about the downed wire/hazard and public impact. DTE continues to conduct quarterly meetings with fire chiefs to gather feedback to improve communication processes.

3. DTE’s Corporate Communications has been proactive and responsive during recent storms.

During a large storm, an electric utility’s communication group must engage proactively with customers and stakeholders, ensure clear and consistent messaging, and provide accurate and timely updates. Effective communication during a large outage promotes public safety, helps maintain customer trust, and supports the overall restoration effort.

Guided by a crisis communications plan and storm playbook, DTE’s Corporate Communications team prepares early in coordination with the ICS team to assess potential storm impacts. They use platforms like Microsoft Teams, email, and social media to proactively disseminate pre-storm preparedness and safety information and engage with the media, customers, and the public. Throughout storms, the team maintains a steady flow of updates to support DTE’s storm teams interacting with customers, cities and municipalities, emergency personnel, the media, and the public. Ahead of the storm and twice daily during the storm DTE executives provide updates to media outlets.

The challenges faced in recent storms have tested this organization, prompting the team to leverage feedback and lessons learned to evolve and improve. For instance, the Social Media team proactively posts updates on several social media platforms and partners with Customer Care to support any social media inquiries received from customers during large storms. Staffing a triage team during each storm allows DTE to handle social media issues that require investigation or follow-up. DTE leaders serve as social media ambassadors during storms and monitor conversations in their own social media private groups and communities, as do all employees.

The PIO engages actively in the ICS process and leads the Communications team in coordinating with other groups to gather information needed to develop and communicate the “storm message” for the Company. DTE has also leveraged both traditional and non-traditional communications outlets to expand its reach during storms. In essence, the mechanics are in place and appear to be working well.

4. DTE’s Call Center has struggled to handle the high volumes of customer contacts during large storms and capacity limitations have affected accessibility. (See Recommendation #2)

DTE's call center telephony has proven a significant source of problems, particularly during the storms of 2021 and 2022, when capacity issues affected caller experiences. During the 2021 storms, call volumes exceeded DTE's call center capacity, which created customer experience issues and limited the ability to speak with an agent. The phone system became overloaded again during the August 2022 storms, leading to various hardware failures.

During the February 2023 winter storm, DTE's telephone and IVR system could not handle the elevated call volumes. Additionally, DTE's customer systems became so overwhelmed by requests coming in from callers and digital channels that the IVR could not process self-service requests. Many customers were directly transferred to a CSR.

DTE addressed these capacity issues in 2023 by replacing its analog phone lines with new digital VOIP/SIP lines, increasing system capacity, and contracting with a third party to provide a high-volume call overflow system to supplement handling self-service requests. The new telephony infrastructure was also stress tested to ensure its capability of handling a very high level of simultaneous customer calls. The telephony supported high call volumes during the January 2024 winter storms with no reported issues. DTE plans to implement a new IVR platform later in 2024. Call center performance also improved during the recent January 2024 winter storm. DTE's callers averaged a 40 second wait time to speak with a CSR and reported a 77 percent service level performance throughout the storm, indicating proper staffing of the center.

5. Unfortunately for customers, large storms have become DTE's default load and stress test of outage communications systems and technologies. *(See Recommendation #2)*

DTE's key outage communications systems and technologies have not performed well under load during major events, as detailed earlier in this section of the report. DTE reported that it had not conducted system-wide outage stress testing before 2023. A third-party technology assessment conducted following the 2023 storms recommended end-to-end stress testing to simulate surge events and identify breakpoints, noting that DTE is unable to simulate storm load end-to-end and that current integrated load testing is practiced in pockets. Unfortunately for customers, large storms appear to have been DTE's default load and stress test of outage communications systems and technologies.

6. Recent approach to ETR improvements better focused on customer needs and expectations. *(See Recommendation #3)*

DTE's has struggled to provide timely and accurate ETRs in most large storms in recent years. Customer feedback has been loud and clear. The August 2021 storms proved the catalyst for DTE's First Estimate Accuracy improvement initiative. Since that time, a cross-functional team has completed a number of initiatives to improve ETR accuracy and timeliness:

- Conducted focus groups and surveys to gather customer feedback
- Instituted Global Estimates for larger storms (*i.e.*, 95 percent restored by Friday)
- Using data analytics to establish default first ETRs; continuing to enhance by location
- Established Regional ETR Coordinator role to focus on ETR creation and management
- Worked with Regional Operations to provide visibility of ETR performance accuracy in daily operations call
- Created a process to update new OMS with global estimates and storm-specific estimates

- Aligned with Everyday Daily Plan priorities to adjust ETR strategy and ETRs
- Began machine learning model development for both storm and non-storm ETRs
- Created a process to communicate with customers about changing ETRs
- Implemented the ETR Dashboard to track ETR accuracy at Regional Operations level
- Developed standard targets for ETR communication delivery timing and monitoring, based on customer input
- Developed a customer-oriented First Estimate Accuracy metric to track ETR performance.
- Used AMI to confirm ETR accuracy.

DTE’s recent efforts appear to be improving ETR communications. During the January 2024 storms, First Estimate Accuracy improved significantly to 70 percent, and the percentage of multiple ETRs sent decreased notably compared to previous storms. Additionally, the Company observed slight improvements in the timeliness of ETR delivery, as shown in the table below:

First Estimate Accuracy Performance

Storm	First Estimate Accuracy	Customers Affected	Too Late	Too Early	Multiple ETRs
August 2022	34%	308,066	4%	17%	45%
February 2023	44%	455,773	5%	22%	29%
January 2024	70%	113,729	1%	21%	8%

D. Recommendations

1. Continue to focus on improving the customer experience. *(See Conclusions #1)*

Over the past several years, DTE has made significant improvements in technology and communication processes to better inform customers, the public, and other stakeholders during a large storm. With ever-changing customer expectations, it is important to continually seek feedback about performance and confirm expectations. DTE should continue to reach out through after-storm meetings, forums, and surveys and adjust communications processes to provide a better experience for affected customers and communities.

2. Verify capacity sufficiency and hardening of outage communications systems and technologies through regular stress and testing. *(See Conclusion #4 and #5)*

During this audit, DTE communicated that stress testing of its outage technologies has become part of their process. DTE indicated its most recent such test was completed in May 2024 simulating more than 700,000 outages. DTE indicates a goal of completing stress testing at least once per quarter.

With further plans to change self-service platforms, and a track record of a poor customer experience, DTE must verify that it indeed has the capacity, resiliency, and redundancy it needs to appropriately communicate with customers during blue-sky days as well as small and large storms. Comprehensive stress and load testing, especially after any upgrades or enhancements, can pinpoint potential failures and significantly reduce the risk of degrading the customer experience.

3. Continue to monitor and measure accuracy and success in creating, updating, and communicating ETRs. (See Conclusion #6)

As DTE continues to enhance its process to generate, update, and communicate ETRs, it should continue to track ETR accuracy and effectiveness. With plans to incorporate machine learning to improve estimation accuracy, DTE should be cautious to ensure it has tested the modeling rules thoroughly and added necessary controls and guardrails should the model go out-of-bounds during future events. DTE should also continue to seek feedback from customers, mayors, emergency management personnel, and other stakeholders as DTE hones the ETR process.